UCL Energy Institute

Whole-systems energy modelling perspectives on net zero in the Scottish islands

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PhD Thesis

THE BARTLETT
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“They can’t do it… no man-made structure will stay up on Costa. The gales would blow the head off a stone giant.”

Bill Sabiston, local farmer (1949) on plans for the first UK grid connected wind turbine at Costa Head, Orkney (Grahame, 2022)

“But will they ever produce enough electricity to make the turbines go round?”

Prince Phillip discussing wind power at the Royal Society (Marriott 2015, p135)

“… always asking the same urgent question: what sort of world do you want to live in?”

Margaret Atwood, on the science fiction author Ursula Le Guin (Atwood, 2018)

“It may be that we of this modern age, who so pride ourselves on the achievements of our time, are prisoners of our age, just as the ancients and the men and women of medieval times were prisoners of their respective ages. We may delude ourselves, as others have done before us, that our way of looking at things is the only right way, leading to truth.”

Jawaharlal Nehru, first Prime Minister of India (Nehru 1946, p19)

Acknowledgements

To my parents, who never told me I couldn’t do anything.

To Catalina, for being the best supervisor.

To the EPSRC for funding the last four years.

To everyone else who has offered help and support along the way.

Lastly, the van - for keeping me sane through COVID.

Declaration statement

I, Chris Matthew confirm that the work presented in my thesis is my own. Where information has been derived from other sources, I confirm that this has been indicated in the thesis.

During the preparation of this work, the AI tool ChatGPT3.5 published by OpenAI was used solely to reword and edit specific sections of text published elsewhere by the author – (4.1-4.2; 4.5-4.8; 5.1-5.4; 5.6-5.7; 6.1-6.2; as summarised in the Research Paper Declaration section). The author reviewed and edited the content as needed and takes full responsibility for the content of this thesis.

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Chris Matthew
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Abstract

Meeting net zero targets will require changes to energy systems, but given the complex dynamics and interactions, the optimal technology mix is uncertain. Whole systems energy modelling can help to understand this and inform policy decisions. Traditionally, this focuses on energy, which could neglect synergies though improved resource utilisation in a circular economy. In this work, modelling of biowaste-to-energy will be integrated with an hourly and net zero supply and demand model of the Scottish islands as a case study.

Three sub-models are developed: demand, biowaste-to-energy, and supply. Firstly, a 100% sample, bottom-up demand model for domestic, commercial, industrial and transport sectors with an hourly resolution is described. Secondly, a techno-economic assessment of the availability and cost-effectiveness of energy from island biowaste is conducted. Thirdly, the generation and interconnections of the islands are modelled. Each are validated with recorded data and then combined in the overall net-zero model in PLEXOS, an energy systems optimisation software. Four scenarios are developed based on current and potential policies, which all achieve net zero through varying combinations and scales of technologies including renewables, storage, hydrogen production, biogas, energy efficiency measures.

The results demonstrate the trade-off between different technologies and their scales. Without investment in efficiency or flexibility, transmission and distribution infrastructure will require significant upgrading. Excessive curtailment of local wind and grid upgrades could be offset by electrolysis, either to meet local demand or potentially export to the mainland. Biogas produced from waste could be key in offsetting hydrogen demand and improving resilience. A wider combination and deployment of distributed technologies could enable greater security, independence, and community acceptance, but would require much support than existing or announced policies.

Impact and research paper statement

This thesis has applications which are relevant to academia, energy policy, and the wider transition to net zero.

The work has firstly contributed to energy modelling literature, with five journal articles (one pending review - detailed in the following section) being published based on the methodology and results. The novelty and contribution consist mainly of aspects focused on improving energy systems modelling methods which could all be applied to other case studies with similar data availability:

(i) The Net Zero model, leveraging supply, demand, and bioenergy models builds on existing models through the sectoral coverage combined with high spatial and temporal resolution.

(ii) The incorporation of circular economy principles with energy systems modelling expands the scope of traditional energy models to also consider resource utilisation.

(iii) The use of time use data for 100%-sample modelling of hourly domestic and non-domestic electricity, heating, and transport demand addresses issues of data availability.

(iv) A detailed framework for the calculation of biowaste collection costs, combined with techno-economic modelling of the levelised cost of energy from biogas.

To enable this, each model has been set up to examine the implications for specific net zero energy policies, which have been translated into model inputs. Scenarios are developed with the trajectory of current and potential policies, which allows a better understanding of how each policy could influence net zero. As the model has more interconnections between sectors and has a higher resolution than those currently used by Government, it allows for more holistic and detailed assessments than that afforded by the modelling work which currently informs policy design. Specific policy recommendations are made in the final chapter which can be used to inform how net zero policy is developed in the UK and elsewhere with decarbonisation targets.

For the islands specifically, outputs from the Demand model will be used collaboration with the DISPATCH project with the University of Edinburgh, University of Glasgow, and Heriot-Watt University. Categorical demand data produced with the model be used for modelling of demand-side-response (DSR) potential in the islands, highlighting where energy is being used, in what form, the potential for decarbonisation measures, and what effect they could have on local networks.

Other outputs are also available for local government or other stakeholders. The collated database of biowaste is publicly available and could be used for assessing the bioenergy potential of a given region. Shapefiles of annual energy demand for individual buildings under different scenarios of energy efficiency policy have been published, which could be used to assess the cost-effectiveness of local energy policies. Data from this thesis has been used at the core to their dissertations by two Masters students at UCL. Other synthetic datasets developed for this thesis could be made available subject to reasonable request.

The methodologies and findings in this research have been circulated to a wider audience within and outside academia, through publication in peer-reviewed journals. These are summarised in the table overleaf, adapted to include the same elements as the UCL Research Declaration Form.

[redacted]

Chris Matthew

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Catalina Spataru (supervisor)

Section	Supply and interconnections	Demand model validation	Biowaste model	Demand model scenarios	Hydrogen
Title	Scottish islands interconnections: Modelling the impacts on the UK electricity network of geographically diverse wind and marine energy	Time-Use Data Modelling of Domestic, Commercial and Industrial Electricity Demand for the Scottish Islands	What drives the viability of waste-to-energy? Modelling techno-economic scenarios of anaerobic digestion and energy generation for the Scottish islands	The multiple benefits of current and potential energy efficiency policies: A Scottish islands case study	Techno-economic assessment of green hydrogen production for decarbonizing the whisky industry on Islay, Scotland
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Acronyms

AD	Anaerobic digestion
ANM	Active network management
API	Application programming interface
BAU	Business-as-usual
BB	Biogas boiler
BECCS	Bioenergy with carbon capture and storage
BEES	Building Energy Efficiency Survey
BEIS	Department of Business, Energy and Industrial Strategy
BESS	Battery energy storage system
BRE	Building Research Establishment
BSuoS	Balancing services use of system
CCC	Climate Change Committee
CCGT	Combined-cycle gas turbine
CCUS	Carbon capture, storage, and utilisation
CfD	Contracts for difference
CHP	Combined heat and power
CREDS	Centre for Research into Energy Demand Solutions
CVRP	Capacitated vehicle routing problem
DBSCAN	Density-based spatial clustering of applications with noise
DDM	Dynamic Dispatch Model
DEAM	Dynamic Energy Agents Model
DECC	Department for Energy and Climate Change
DEFRA	Department for Environment, Food and Rural Affairs
DESNZ	Department for Energy Security and Net Zero
DLR	Dynamic line rating
DNM	Distribution Networks Model
DNO	Distribution network operator
DSO	Distribution system operator
DSR	Demand side response
DUKES	Digest of UK energy statistics

ECO	Energy Company Obligation
EDM	Energy demand model
ENSMOV	Enhancing the Implementation and Monitoring and Verification
EMEC	European Marine Energy Centre
ENW	Electricity Northwest
EP	Energy Plus
EPC	Energy performance certificate
EV	Electric vehicle
FES	Future Energy Scenarios
FiT	Feed-in-tariff
FSO	Future system operator
GIS	Geographic information system
GSP	Grid supply point
GVA	Gross value added
HDD	Heating degree days
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
LA	Local authority
LAEP	Local area energy plan
LCOE	Levelised cost of electricity (or energy)
LCOH	Levelised cost of hydrogen
LDP	Local development plan
LMP	Locational marginal pricing
LTDS	Long-term development statement
MAPE	Mean absolute percentage error
MT	Medium term
NDB	Non-domestic buildings
NINES	Northern Isles New Energy Solutions
NPG	Northern Power Grid
OCGT	Open-cycle gas turbine
OHLEH	Outer Hebrides local energy hub
OSM	Open Street Map
P2P	Peer-to-peer
REG	Reciprocating engine generator
REPD	Renewable energy planning database
RHI	Renewable Heat Incentive

RMSE	Root mean square error
ROC	Renewable obligation certificate
SAP	Standard assessment procedure
SDG	Sustainable development goals
SHCS	Scottish housing condition survey
SHEPD	Scottish Hydro Electric Power Distribution
SMR	Small modular reactor
SPEN	Scottish Power Energy Networks
SRMC	Short-run marginal costs
SSEN	Scottish and Southern Electricity Networks
ST	Short term
TNuoS	Transmission network use of system
UKERC	UK Energy Research Centre
UKPN	UK Power Networks
ULEZ	Ultra low emission zone
UPRN	Unique property reference number
V2G	Vehicle-to-grid
VoLL	Value of Lost Load
VOM	Variable operations and maintenance
WPD	Western Power Distribution

1 Introduction

Over the 20th century, access to affordable energy has facilitated some of the most concentrated improvements to living standards in human history. Enshrined in the Sustainable Development Goals (SDG) of the United Nations as SDG 7, access to affordable and secure energy has implications and synergies for achieving all other SDG goals. These include raising living standards through healthcare, water sanitation, and education; improving household incomes and resilience; and empowering economic, social and political inclusion (Fuso Nerini *et al.*, 2018). Over the last hundred years, this explosion of energy accessibility and affordability has been enabled by fossil fuels. They are in many ways the ideal energy carrier, with high energy densities, ease of storage, scalability of technologies - not to mention the trillions of pounds invested, making their extraction increasingly efficient (Yergin, 2011). The accumulation of historic use has however revealed a downside which increasingly out-weighs the benefits.

Greenhouse gases (mainly carbon dioxide [CO_2], but also methane, ozone, and nitrous oxide) are now known to cause planetary-scale heating. Anthropogenic emissions are currently about three-quarters directly or indirectly made up of energy consumption (the remainder being related to land-use). This has begun to disrupt weather and ecosystems, alongside all the human activities which depend on them. With increasing concentrations of greenhouse gases, the higher the probability of disruption to the natural systems upon which global prosperity is founded (IPCC, 2022). Over the course of the last six Intergovernmental Panel on Climate Change (IPCC) reports produced since 1990, the urgency of calls to address the causes of anthropogenic climate change have steadily increased. Less than a decade after the Paris Agreement in 2015, its landmark target of limiting global heating to less than 1.5°C seems less and less likely to be achieved (UNFCCC, 2023). Greater temperature increases exponentially increase the risks of disruption to the weather, society and the economy. Damages in the billions of dollars caused by extreme weather have already demonstrably increased in the last few decades. Reducing emissions are key to mitigating the worst of these impacts, with net zero being the ultimate goal (IPCC, 2022).

The IPCC defines “net zero” as anthropogenic CO_2 emissions balancing with anthropogenic removals from the atmosphere (IPCC, 2022). This leaves the responsibility with man-made systems to achieve net-zero, rather than reliance on other natural systems. Essentially, technology choices have brought about the situation, so should form the solution. Technology here is defined as any man-made objects, devices, or networks influencing how energy is used by society - they include wind turbines, combined-cycle gas turbines (CCGTs), heat pumps, or electric vehicles (EVs), but also double-glazed windows or other building fabric improvements. Given the wide-ranging nature of emissions from all sectors of society, net zero solutions clearly need to consider effects of the whole systems. In this work, the UK Energy Research Centre (UKERC) definition of energy systems will be used: ‘the set of technologies, physical infrastructure, institutions, policies and practices… enabl[ing] energy services to be delivered to… consumers’ (Chaudry *et al.*, 2011). In the context this and the IPCC definition of net zero as man-made emissions balancing man-made removals, the focus is on technology and infrastructure deployment which could be used to meet the goal of net zero.

1.1 Net zero energy systems and the circular economy

Traditionally, energy systems have consisted of suppliers, which extract, distribute, or convert energy (mainly fossil fuels); and consumers, who purchase energy for domestic or commercial requirements. With a cheap primary energy source which could be stored and economies of scale, energy systems were for the most part structured as large, centralised suppliers transferring energy one-way to consumers (Yergin, 2011). Achieving net zero though will most likely require this to change for several reasons.

Meeting the IPCC definition of net zero will require minimising unabated fossil fuel use to avoid expensive CO_2 removal costs, necessitating that other technologies and fuels are used to meet the energy needs of society (IPCC, 2022). Electricity, due to utilising existing infrastructure and having the widest compatibility of demand, is best suited to replacing fossil fuels. By 2050 - the year of many countries net zero targets - up to 70% of energy demand could be electrified, requiring a generation system five times larger than currently (Energy Transitions Commission, 2021). To avoid direct emissions from electricity generation, more mature technologies such as wind and/or solar PV will likely form the backbone of generation systems depending on the region. However, energy systems largely based on renewables come with greater complexity. They cannot be dispatched like thermal fossil fuel generators, they lack inertia to keep the system balanced, and electricity cannot be stored (Davis *et al.*, 2018). Electricity also will be uneconomical or technically unsuitable for certain demands, such as energy-intensive steel or concrete production. These factors will contribute to more complex and interlinked net zero energy systems, as shown in Figure 1-1.

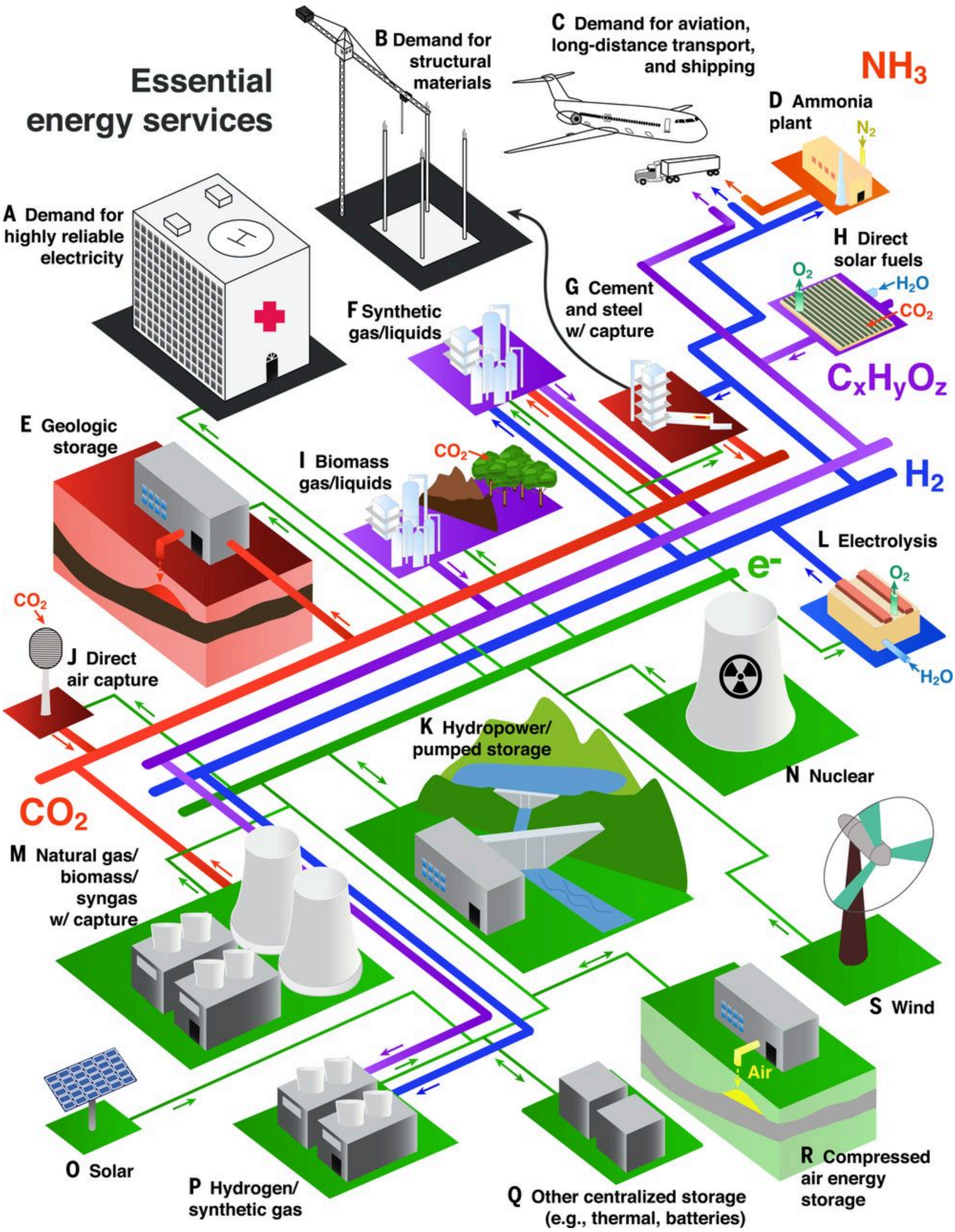

Figure 1-1: Schematic of a net-zero energy system with no direct CO_2 emissions (Davis *et al.*, 2018).

For electricity, anticipated to replace the majority of fossil fuels, it has become clearer in recent years that enormous growth in renewable generation (wind and solar PV, but also hydro and potentially nuclear - S, O, K, and N in Figure 1-1) is needed (IEA, 2022b). However, the complex dynamics between supply, demand, and the types of technology make other aspects less certain. The scale of generation required will depend on demand-side technology changes and realised energy efficiency (A, B, and C - Figure 1-1). Without efficiency improvements in the UK, the generation system would need to be four time larger and prohibitively expensive (Barrett *et al.*, 2021). Greater reliance on intermittent renewables also necessitates increased energy storage, from timescales of seconds up to months, which will require varied technologies to meet the specific timescales and demand types (Q and R - Figure 1-1). Balancing the grid will become more complex, necessitating balancing services provided through new methods and market structures, such as peer-to-peer (P2P) energy trading networks which can be used to manage local energy supply and demand in a more cost-effective way (Keay-bright, Elks and Chapelle, 2021). More generation will increase the prominence of network constraints, especially at times of peak demand, which could make the aforementioned measures more economical compared with expensive upgrades to transmission infrastructure (IEA, 2015). Net zero energy systems with a greater reliance on electricity rather than fossil fuels will be more complex, digitised, and networked, but wider technology portfolios should provide greater security (National Grid, 2023).

Whilst anticipated that electrification will play the greatest role in minimising unabated fossil fuel consumption, certain types of demand will likely be more economical to be met through other energy types and technologies. Hydrogen, ammonia, and other synthetic fuels (D, F, H, and L - Figure 1-1) will likely play a role. Electrolysis (the production of hydrogen from water using electricity) particularly can link between these markets and electricity - periods of excess renewable generation could be used to power electrolysers cheaply. Under the International Energy Agency's (IEA) Net Zero Emissions scenario, meeting potential global annual hydrogen demand of 475 Mt by 2050 would require 3,670 GW of electrolyser capacity (IEA, 2022b). Hydrogen could also be produced with fossil fuels as feedstocks with CO_2 capture and storage at the point of production. The technical requirements of heavy industry, shipping, and aviation though could make other fuels such as ammonia more suitable (IEA, 2022b). How the markets for these fuels will develop remains highly uncertain given the range of technical options.

Maximising the chances of achieving net zero goals could be increased by also considering changes to how resources are used (B, C, and I - Figure 1-1). The circular economy could play a role in this, as defined by three key principles (Ellen MacArthur Foundation, 2023):

(i) *Eliminating waste and pollution:* moving away from a “take-make-waste” system to one where the end-of-life for products is considered in the design process to avoid landfill;

(ii) *Circulate products and materials:* keeping in use at their highest value, ideally as products or as materials when they can no longer be used;

(iii) *Regenerate nature:* avoiding waste and pollution will leave more room for natural processes to thrive.

Reducing material burden from the demand side through innovative design and materials use could minimise the burden of energy intensive raw materials. Improved utilisation of waste could have numerous benefits - reducing costs for consumers, local government and companies; minimising emissions; and greater security, resilience, and flexibility of local energy systems (Ricardo Energy and Environment, 2019). Technologies such as anaerobic digestion (AD) (I - Figure 1-1) to produce biogas, could simultaneously address biowaste management, reduce greenhouse gas emissions, and provide dispatchable electricity or heat (Al Seadi *et al.*, 2008). Complex synergies between net zero, circularity, and all sectors of the economy could help to maximise the likelihood of achieving net zero and minimising the worst effects of climate change. For the purposes of this work, with the resources identified for the case study area and their potential interaction with its energy system, the focus with respect to the term “circular economy” will be mostly with respect to the principles of eliminating waste and circulating materials (points i and ii above).

1.2 Energy in the Scottish islands

Several Scottish islands have for some time been a microcosm of what a future net zero energy system could look like for the UK. The have abundant renewable energy capacity, but this is constrained by at-capacity local networks, leading to high curtailment. Reducing this has led to several innovative projects targeting the high rates of fuel poverty, producing hydrogen using excess renewable generation, and trialling local energy trading schemes. It should also be noted that the islands do not have gas distribution networks (aside from a small independent network in Stornoway) (Scottish Government, 2017).

The Scottish islands have long been recognised for their renewable energy potential, with the first grid connected wind turbine in the UK in 1951 at Costa Head, Orkney (Swift-Hook, 2012). The significant wind resource of the islands makes wind generation more economical, with some generators achieving capacity factors greater than 50% - which is usually reserved for offshore wind. Today, Orkney has the highest number of feed-in-tariff (FiT) wind turbines of any local authority in the UK, with one wind turbine for every 14 households (BEIS, 2020d). The islands are also have an internationally significant marine energy resource, with one of the only marine energy research facilities in the world - the European Marine Energy Centre (EMEC) (EMEC, 2019d). This facility has played a key role in gaining recognition of the potential for marine energy, with greater marine capacity awarded in the contracts for difference (CfD) auctions with each passing round (DESNZ, 2023c).

The three major island groups of Orkney (Figure 1-2), Shetland and the Western Isles all have renewable capacity (mostly wind, but on Orkney also tidal stream) which at periods of high generation can exceed the thermal capacity of local transmission networks. To allow this heightened renewable capacity on the network, these three main island groups all have active network management systems (ANM). This monitors and controls distributed generation to balance the grid - when generation is in danger of exceeding grid capacity, certain generators are automatically curtailed by the ANM system. While this has allowed more wind capacity than the limits of local distribution networks, some generators have had curtailment of up to 50% (Xero Energy, 2014). This could provide a glimpse into the future for the whole UK, where in 2022 at just 27% of the 2030 offshore wind target of 50 GW, network constraints are already a major bottleneck (National Grid, 2023).

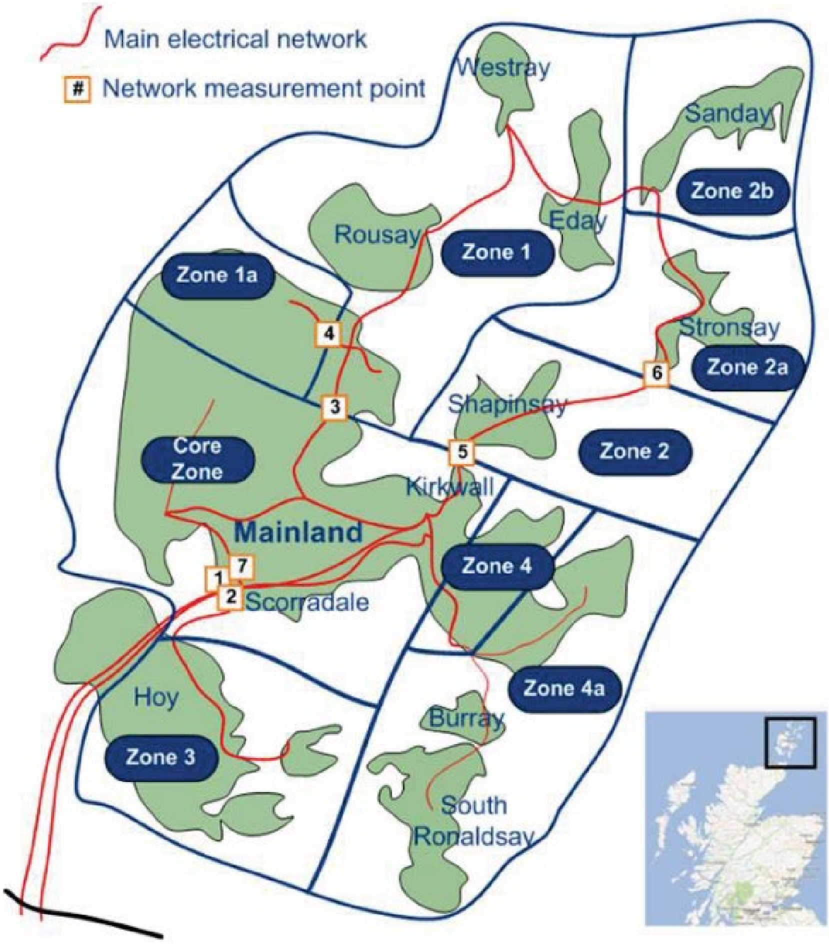

Figure 1-2: Outline of the ANM system on Orkney, where the numbered squares highlight network constraints between zones of demand and generation (Orkney Renewable Energy Forum, 2014).

Mainland transmission constraints are also a limiting factor. Whilst almost all permanently inhabited islands are connected to the mainland UK electricity network (excepting Shetland which currently has its own network) (SSEN, 2019), the capacity of this connection limits the utilisation of the abundant local renewable energy resources (Orkney Renewable Energy Forum, 2014). Since the early 2000’s, this has been continually debated between Ofgem (the regulator), Scottish and Southern Electricity Networks (SSEN - the distribution network operator), and generation developers. With the recent construction of the 600 MW Shetland interconnection and approval of the smaller 220 MW one for Orkney (discussions are ongoing to triple the planned 600 MW Western Isles connection to 1,800 MW to facilitate offshore wind off the west coast of the islands) (SSEN, 2023a), it seems likely that all main island groups will have a mainland interconnection in excess of local peak demand by 2030. These interconnections have been conditional on the approval of sufficient generation to meet the planned transmission capacity, which should be completed around the same time (SSEN, 2023b).

However, the scale of generation and interconnection planned for the three main islands will not uniformly benefit local communities. The Shetland interconnection and associated 370 MW Viking wind farm has been taken to court throughout its development (Carrell, 2015). Its size relative to local demand means that the majority of energy will be exported to the mainland, while local communities on the periphery of the UK network will deal with the impacts of development (Munro, 2019). As well as for smaller island regions, which do not currently have interconnectors or upgraded renewable capacity planned, other energy paradigms could be needed if they are to benefit from the net zero transition. While this could still include development of renewable capacity, as the islands have demonstrated successfully with a number of community owned projects (Haggett *et al.*, 2013; McHarg, 2015), other development models could improve support for projects. The smaller and heterogeneous Scottish islands will require tailored net zero solutions specific to their local contexts (Ricardo Energy and Environment, 2016).

Despite the excess of renewable energy in many cases, the islands are characterised by high local energy costs due their generally isolated and poorly connected locations, both in terms of energy infrastructure and transport links to the mainland (excepting those closest to the mainland) (Orkney Renewable Energy Forum, 2014). The islands have the highest rates of fuel poverty in the UK - the top five highest by local authority in 2019 were all islands (North Ayrshire was the only one better off), at 19.0-24.3% of households (Scottish Government, 2022b). The islands have high fuel prices due to a lack of a gas network or other transportation infrastructure (Orkney Islands Council, 2017a), and 76% of the building stock has an energy performance certificate (EPC) rating of D or lower (Scottish Government, 2021b). Improving understanding of the effects and benefits of energy efficiency upgrades could therefore have a significant impact on local communities and their experience of high energy costs.

The combination of an excess of local renewable energy, high energy prices, and transmission constraints have led to various innovative energy projects being trialled, particularly for hydrogen (Table 1-1).

Table 1-1: Summary of innovative energy projects on the Scottish islands.

Name and Location	*Description*	*Reference*
HyFlyer, Orkney	Hydrogen/electric powered 300-mile flight for a six (then 19) seater aircraft, fuelled by locally produced green hydrogen.	(EMEC, 2019c)
HySpirits, Orkney	Feasibility study of using hydrogen to decarbonise two distilleries, recommended dual fuel due to supply issues.	(EMEC, 2019e)
SWIFTH_2, Western Isles	Feasibility study of using hydrogen to power local island ferry route.	(Sandwick Point Trust, 2019)
BIG HIT, Orkney	1 MW proton exchange membrane electrolyser powered by curtailed local renewable energy, special transport vehicle, hydrogen storage, and fuel cell for harbour.	(Fuel Cells and Hydrogen Joint Undertaking, 2018)
Flotta Hydrogen Hub, Orkney	Combining hydrogen electrolysis from nearby offshore wind with oil and gas infrastructure for transport.	(Flotta Hydrogen Hub, 2021)
GHOST, Shetland	Feasibility of using tidal energy to produce hydrogen and oxygen for local use, including the space port.	(Energy and Climate Change Directorate, 2023)

Other options to deal with excess energy on the islands have also been demonstrated. The TradDER P2P trading trial in Orkney involved two wind turbines, two batteries and 136 electric storage heaters connected (about 1% of total households). Over a year, 8.26 MWh was traded to reduce curtailment (Keay-bright, Elks and Chapelle, 2021). The Northern Isles New Energy Solutions (NINES) project in Shetland was designed to minimise peak demand, increase renewable generation, and therefore reducing dependence on fossil fuels (which the islands network is dependent on). It used a 1 MW battery, heating and hot water demand side response (DSR) for selected households, thermal storage, and extra wind capacity (SSEN, 2014). These have allowed increased utilisation of renewable generation without needing to address network constraints, which will reduce balancing costs and provided additional revenue for generators (Keay-bright, Elks and Chapelle, 2021). These schemes provide a valuable experience of working P2P networks and DSR which could be crucial in minimising the effects of network constraints at times of peak renewable generation for the whole UK.

Many of the industries on the islands are food and drink based, creating opportunities for biowaste (referred to here as waste composed of organic matter, which would likely otherwise end up in landfill) to be used more efficiently through circular economy principles. Perhaps the best example of a holistic and circular energy systems approach is the Outer Hebrides Local Energy Hub (OHLEH). The OHLEH combines innovative circular economy principles with a multi-sector and energy vector approach. Fish farm and processing waste is converted into biogas via anaerobic digestion, which combined with an on-site wind turbine produces hydrogen that powers the local waste collection vehicle and the waste processing facility (Community Energy Scotland, 2019). It provides an excellent example of how cross-sectoral thinking can help to more efficiently address demands, which displace fossil fuels, while improving the utilisation of resources. Extending the concept to other food and drink sectors on the islands, such as whisky distilling, could have the same benefits.

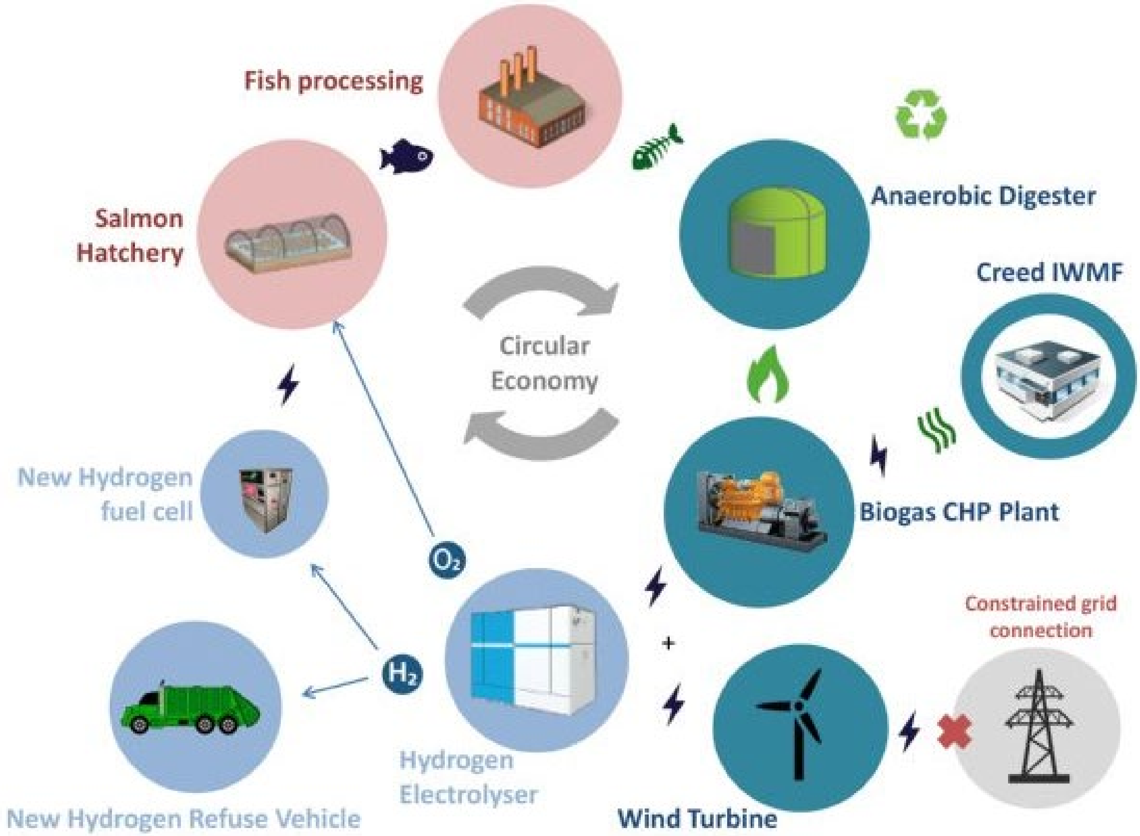

Figure 1-3: Flow chart of the energy processes involved in the OHLEH (Community Energy Scotland, 2019).

As a case study for modelling the implications for a net zero energy system, the Scottish islands therefore have many characteristics highlighting the challenges that rest of the UK faces. Excess renewable energy is curtailed due to insufficient grid capacity, with innovative demand and supply side solutions trialled to address this such as distributed storage, hydrogen, DSR, and P2P trading markets. Understanding the trade-offs between these technologies could help to shed light on the transition for the wider UK and other island regions.

1.3 Research questions and objectives

Before presenting the research questions and objectives, several key terms used will be defined to ensure clarity on their use. These are not the only definitions of the terms, but what will be used for this thesis.

(i) *Energy systems:* 'the set of technologies, physical infrastructure, institutions, policies and practices… enabl[ing] energy services to be delivered to… consumers' (Chaudry *et al.*, 2011).

(ii) *Net zero:* anthropogenic CO_2 emissions balancing out with anthropogenic removals from the atmosphere (IPCC, 2022).

(iii) *Circular economy:* in the context of energy systems, the synergies between "eliminating waste and pollution" and "circulating products and materials" are greatest so will be the focus (Ellen MacArthur Foundation, 2023):

(iv) *Technology:* man-made objects, devices, or networks which influence how energy is used by society.

(v) *Biowaste:* waste products from domestic, commercial, or industrial sources which are biodegradable. This includes waste from food, garden, and food processing, but excludes agricultural, forestry, or sewage residues per the EU definition (European Commission, 2021).

Significant uncertainty remains in the transition to net zero. Major changes of technology networks, market structures, and energy policy, will be needed to meet net zero aspirations. Understanding the implications of these changes, the interdependency of technology choices, and overall complexity of an issue which encompasses all sectors of the economy will be essential in achieving net zero. Whole new sectors, such as hydrogen demand, will need to be created (IEA, 2022b). Only strategic and whole systems (not isolated sectors) policy design will be able to manage this (National Grid, 2023). Modelling energy systems can help to understand these aspects and so how decisions and policies could be designed to address issues. Energy systems modelling can be considered as computational representations of an energy system which replicate its behaviour in ways relevant to the aspects being interrogated, used to optimise, evaluate, and understand the complex dynamics between components.

Understanding the dynamics of an energy system dominated by intermittent renewables requires a high temporal resolution to consider how supply can be matched with demand. Rather than annually, analysis of renewables must consider behaviour at times of peak stress for assurance that they can provide the consistent energy expected. The uncertainty of other net zero aspects highlights the need to increase the range of technologies considered. Advances in data science have demonstrated the feasibility of 100% sample demand modelling (Steadman *et al.*, 2020), which can capture the full range of how energy is used and so how it could change in a net zero energy system. Synergies of including efficiency and circular economy principles in energy systems modelling has also been increasingly recognised. Particularly for circular economies, this requires the integration of other, resource-focused models which are not traditionally included by energy models (Seljak, Baleta and Mikulčić, 2023).

While the UK and Scottish government net zero policy has made significant progress in some areas, others have been highlighted as lacking (CCC, 2023). Particularly at the UK level, focus and success so far has been with larger-scale technologies, but less so around distributed, community-involved options. Integrating circular economy principles could also be integrated to improve the resilience and efficiency of energy systems. This research focuses on the utilisation of biowaste for energy as a way to broaden technology portfolios and improve resilience, yet to date synergies between resources and net zero have been poorly considered in UK policy (UK Government, 2021). Energy systems modelling can help understand how a plurality of technologies operate and interact at a network scale. Modelling the intermittency of renewables requires an hourly resolution, while considering all aspects of demand will enable consideration of a range of technology options. Given the computationally intensive nature of this modelling, a smaller case study area than the whole UK is required for which the Scottish islands present an ideal opportunity.

To consider these issues, this research will address the following questions:

(i) What are the potential net zero energy systems configurations for the Scottish islands in terms of technologies, scale, and their deployment within the constraints of the islands?

(ii) How can energy systems modelling incorporate circular economy considerations in the area of biowastes and what role could it have in a net zero energy system?

(iii) What implications does hourly, 100% sample, bottom-up energy systems modelling of the Scottish islands have for energy policies and ultimately achieving net zero?

To answer these research questions, the following objectives are proposed (Table 1-2):

Table 1-2: Objectives for this thesis and how they are achieved.

Objective	*Research question(s)*	*Methods*	*Method section*	*Result section*
Develop hourly net zero model capturing key market and technology behaviours	1, 2, & 3	Hourly PLEXOS model with electricity, hydrogen, and biogas supply/demand	Parts of 3, 4, 5 & 6	7 & 8
Design scenarios based on current and planned energy policies	1, 2, & 3	Review of policies and technical/economic constraints used to inform main scenarios and sub-model scenarios	3.3, 4.6, 5.8 & 6.4	4.7, 5.8, 6.5 & 7
Examine the role of hydrogen and electrolysis in net zero	1 & 3	Hydrogen market with supply and demand incorporated into Net Zero model	3.2.2, 3.3, 3.4, 3.5.3, 3.6.5, 6.1.1, 6.3.3 & 6.4.3	6.5.6, 7.3, 7.4 & 7.5
Estimate the relative costs of each scenario and who would be responsible for categories of cost	1, 2, & 3	Results from other models used to calculate costs by aspect, allowing them to be allocated to different parties	3.6, 5.3, & 6.1	4.7.4, 4.7.6, 5.6, 5.7, & 7.4
Develop hourly Demand model for all sectors with publicly available data	1 & 3	Time use and other datasets used to represent and validate demand for the islands	4.1-4.5	4.5
Investigate current energy efficiency policies and what their effect on overall demand could be	1 & 3	Demand model used with ranges of policy support to calculate total demand and costs	4.6	4.7 & 4.8
Analyse factors influencing cost of energy from biowaste	1 & 2	Resource availability, clustering algorithms, calculation of collection costs, and facility configuration; scenarios-based assessment of these factors.	5.1, 5.2, 5.3, & 5.4	5.6, 5.7, & 5.8
Determine potential contribution of biowaste to net zero targets	1, 2, & 3	Biowaste database and techno-economic modelling incorporated into Net Zero model in PLEXOS.	As above	As above, plus 7.1 and 7.3.4
Capture the techno-economic characteristics and behaviour of various technologies	1 & 3	Electricity market only model developed and validated using actual demand data, with renewable capacity factors and other aspects.	3.2, 3.5 & 6.1	6.2 & 6.5

The thesis uses a model of the behaviour of net zero technologies and their interactions at a high temporal and spatial resolution. It does not consider negative emissions technologies or methods due to the context of the islands and other aspects discussed in Section 3.5. Due to the complexity of the model, only four deterministic scenarios are presented for the end point of the year 2045. Scenarios are presented not as optimised outcomes, but as alternative pathways which illustrate a range of potential outcomes. These are not intended to be directly compared, but due to the higher resolution modelling can provide a more nuanced perspective on the implications of major technology configurations for net zero (e.g. a demand-led vs supply-led transition) than a broader scale model. This does however make the modelled results are highly dependent on the assumptions used to set up the solution space- particularly projecting two decades ahead. The assumptions used are described in Section 3.5, with the sensitivity of results to these assumptions analysed in Section 7.4.

1.4 Thesis structure

The main output of this thesis is the development of a net zero energy systems model for the Scottish islands as a case study. Scenarios are developed by varying the inputs of the three main sub-models according to the logic of four deterministic scenarios which are mapped out within the solution space of the Future Energy Scenarios (FES) for 2045- the year of Scotland's net zero target (intervening years are not modelled, but investment pathways are discussed in Section 8.4). These are deterministic and model the energy system only. Firstly, literature is reviewed, with gaps identified used to inform the structure of the subsequent modelling. PLEXOS is identified as the most suitable modelling tool (Chapter 2). Then, the overall methodology and Net Zero model are described, alongside the scenarios based on combinations of technologies for the islands (Chapter 3). The model is structured through combined modelling of Electricity and Gas Markets (objects in PLEXOS will be capitalised throughout - markets here referring to the separate model groups in PLEXOS, which has historically been used to model electricity or natural gas dispatch separately), which allows the optimisation of both, linked through the operation of electrolysis to produce hydrogen. Constraints, such as network thermal capacities, are applied along with techno-economic characteristics which capture the behaviour of each technology.

As PLEXOS is designed to optimise energy market dispatch, other models are needed to generate inputs for the Net Zero model, which are described in the following chapters (demand - Chapter 4; biowaste-to-energy - Chapter 5; supply and networks - Chapter 6). For each, the methodology is described, where possible the model is validated using recorded data, the model is used to address questions specific to that sub-model, the translation of the Net Zero model scenarios into that sub-model are described, scenario results are presented and lastly discussed with policy implications in mind. These scenario outputs are then used as inputs to the Net Zero model (described in Chapter 3 - summarised in Figure 1-4), with results for this presented and analysed in Chapter 7. Conclusions and policy recommendations drawing on the results of the Net Zero model (Chapter 3) and sub-models (Chapters 4-6) are then presented (Chapter 8).

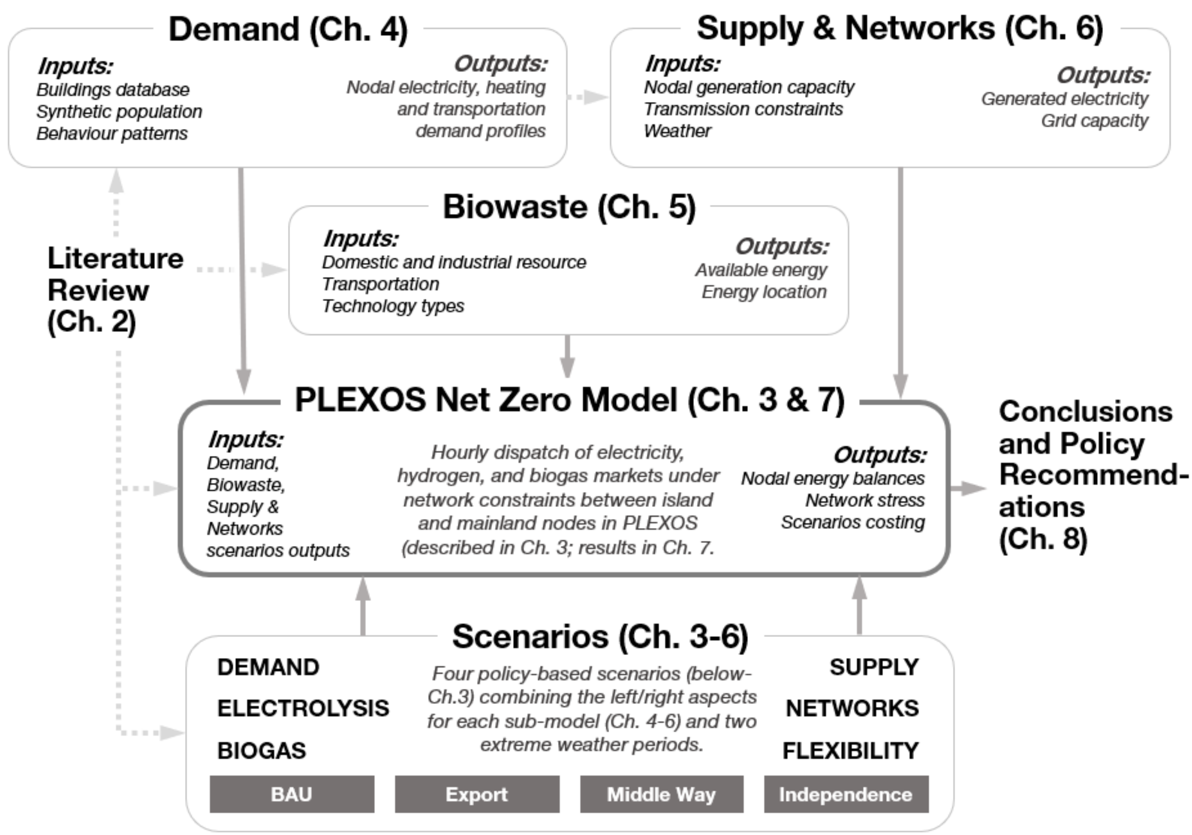

Figure 1-4: Structure of the Net Zero model and thesis, with chapter numbers given. Note that the Net Zero model is described in Chapter 3, with results in Chapter 7. The scenarios are outlined in Chapter 3, with more detailed description of how they are translated into model inputs for Chapters 4-6.

To summarise each chapter in more detail:

Literature review (Chapter 2): literature is reviewed to identify gaps which the methodology will address. Energy systems models and methodologies are reviewed, concluding that PLEXOS is a framework able to capture aspects essential to understanding net zero. Demand and biowaste for energy literature identifies how models are structured and could be improved. UK energy policy is discussed to understand how this could inform the model's structure and projections for net zero. Lastly, the existing modelling work on the Scottish island context is discussed to inform the model structure.

Whole model and scenarios outline (Chapter 3): The overall methodology of the Net Zero model is described, using inputs from the sub-models described in Chapters 4-6. The optimisation steps of PLEXOS are outlined and the logic of how electricity and hydrogen markets are modelled is discussed. Key assumptions and how they could affect results are highlighted. The logic of the four main scenarios is covered, with an outline of how they are transformed into the model inputs described in subsequent chapters.

Demand model (Chapter 4): a demand model is developed for this thesis based on time use data to address data availability and privacy issues. It has categorical, hourly demand data for domestic, commercial, and industrial demand, which is validated using recorded electricity demand data. Hydrogen demand is estimated based on demand for sectors which are unlikely to be electrified. Scenarios are presented for ranges of energy efficiency policies, from the results are used to address questions comparing specific technologies, their range of benefits/costs, and their distribution.

Biowaste-to-energy model (Chapter 5): a biowaste database has been developed for several resource types specific to the islands whilst minimising competing resource demands. A collection costs model using recursive density-based spatial clustering of applications with noise (DBSCAN) clustering, a capacitated vehicle routing problem (CVRP) solver, and Open Street Map (OSM) road networks is developed, for which the resource database is used to optimise collection costs. Results of both are used to as inputs to a techno-economic model to assess the levelised cost of energy (LCOE) and feasibility of resource utilisation. This addresses questions of what resource could be feasibly used for energy, what facility configuration and technologies would be best, and what the cost of energy could be.

Supply and networks (Chapter 6): firstly, a simplified, electricity markets-only version of the Net Zero model is described and validated using recorded demand data. Secondly, this model is used with scenarios of generation to understand what effect geographic and supply diversity could have on the UK network specifically for the Scottish islands. Lastly, the scenarios of supply and networks for the final model are described, with capacities for each aspect presented.

Net zero model results (Chapter 7): with the other models described and validated, they are used as inputs to the model outlined in Chapter 3, with results presented and discussed. Of particular focus are the overall energy balances of the islands for electricity, hydrogen, and biogas; behaviour of the electricity network, particularly considering network constraints and flexibility; the role of hydrogen and electrolysis; and comparison of the costs and their distribution between scenarios.

Conclusions and policy recommendations (Chapter 8): the outcomes of each model are reiterated and described from a holistic perspective in relation to each other. Based on these observations, specific policy recommendations addressing the issues raised from each chapter are discussed.

2 Review of literature

In this section, literature relevant to whole energy systems modelling is reviewed as the basis of this research. Based on this and the research objectives, there are four main areas of focus:

(i) Energy systems models and their structures, considering what aspects of models are key to understanding the net zero transition, particularly considering geographic and supply diversity.

(ii) Energy demand models relevant to the whole systems modelling review, covering aspects such as sectoral coverage, 100% sampling, and data availability alongside how these can be addressed.

(iii) A circular use of biowaste in an energy systems context and how it can be modelled using availability assessments, collection models, and overall feasibility frameworks.

(iv) Decarbonisation policy in the UK and Scotland, considering what policies are in place currently, uncertainty around their trajectory, and how net zero is modelled by the Government.

(v) Scottish islands energy systems modelling, as the case study of this thesis, according to sections (i-iii) above.

2.1 Energy systems modelling literature

Understanding the dynamics of decarbonised, net zero energy systems requires energy systems modelling. Traditionally, this has focused on optimising generation and power systems, but as systems become more complex and interlinked, they increasingly need to consider all energy sectors. This section will provide an overview of energy model typologies, some examples using the optimisation software PLEXOS, the importance of supply and geographic diversity, and conclude with modelling done for the Scottish islands.

2.1.1 How are models structured?

There are numerous works categorising and tracking the use of energy systems models (Després *et al.*, 2015; Hall and Buckley, 2016; Lopion *et al.*, 2018; Ringkjøb, Haugan and Solbrekke, 2018; Prina *et al.*, 2020; Fodstad *et al.*, 2022). This section summarises the main features identified in these reviews, how they are suited to different applications, and an overview of some main models. The IPCC lists five key model differences which will be discussed: sectoral coverage, geographic coverage, time resolution, method, and programming techniques (IPCC, 2022).

Energy models can be categorised as either bottom-up, considering techno-economic characteristics of individual participants, or top-down, using economic equilibrium to understand technology diffusion. Although hybrid models exist, integrating the two methods has proven challenging (Lopion *et al.*, 2018). Results can either be soft-linked (transferred manually between models) or hard-linked (transferred automatically) (Prina *et al.*, 2020). Bottom-up models tend to have greater flexibility in both spatial and temporal resolutions, but both can have hourly up to yearly resolutions. In Figure 2-1 (Ringkjøb, Haugan and Solbrekke, 2018) each numbered area represents a different modelling framework, demonstrating the wide resolutions available depending on the model setup and use case.

Using techno-economic characteristics, models are generally designed to either optimise the economic dispatch of energy over short timescales (resolutions of seconds up to days) or for energy systems planning (years spanning up to 2050 or beyond). Typically, these optimisation problems are approached separately, as integrating short-term variability of renewables at scales of multiple years is computationally intensive. Results can be integrated with other models as inputs (Ringkjøb, Haugan and Solbrekke, 2018), either through soft - or hard-linkages.

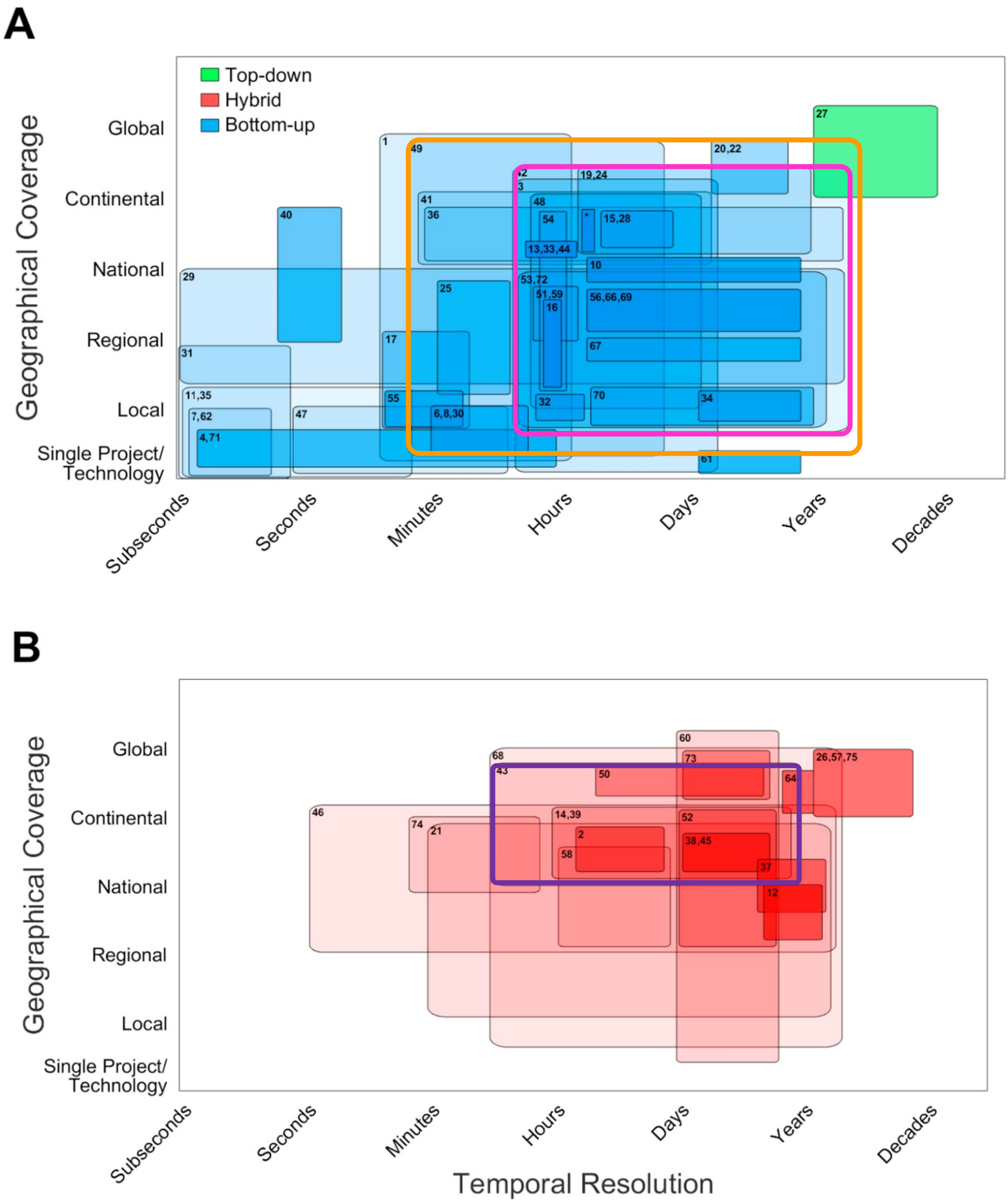

Figure 2-1: Comparison of top-down, hybrid (A), and bottom-up (B) energy systems models with high renewable penetration (Ringkjøb, Haugan and Solbrekke, 2018). *Highlights (added by author) are PLEXOS (orange), MARKAL (pink), and MESSAGES (purple).*

To understand the synergies between sectors as demand from fossil fuels is replaced in energy systems, more complex models with greater sectoral coverage is required. While many energy systems models have historically covered electricity and/or gas, a fully net zero energy system model should incorporate wide-ranging demand sectors and commodities (Ringkjøb, Haugan and Solbrekke, 2018). This can include any or all sectors such as electricity, heating, hydrogen (or power-to-X), transport, and/or industry (Després *et al.*, 2015). Acknowledging the significant uncertainties regarding the scale and nature of energy demand, models increasingly incorporated the deployment of technologies such as heat pumps, electric vehicles, hydrogen, and DSR (Fodstad *et al.*, 2022). Rather than focusing on individual sectors in isolation, the widest combination of technologies and sectors should allow for more optimal solutions to be considered. For renewable dominated systems, an additional challenge arise with the incorporation of distribution into transmission network models to address constraints (Prina *et al.*, 2020).

Another way in which energy systems models can differ is whether they are open or closed source (referring to the code and algorithms used to run the models). Generally speaking, open source models tend to be developed by research organisations as freely adaptable and expandable (Widl *et al.*, 2022). This allows for greater transparency in models, but setting up models can require a greater amount of expertise, with more limited support options and documentation if they are not inherently designed with usability in mind (Berendes *et al.*, 2022). Closed source models are usually developed by commercial organisations, with proprietary models that can be available freely under an academic license or at cost for other users (Widl *et al.*, 2022). Given the demands of paying customers, there can be dedicated support and documentation available for these models, such as for PLEXOS (Energy Exemplar, 2023a). Both types of models can have the same capabilities and challenges with respect to temporal resolution, spatial resolution (particularly at a high enough detail), techno-economic detail and sector coupling (Prina *et al.*, 2020).

2.1.2 Review of energy systems models

Energy systems modelling in the UK is primarily influenced by variants of the MARKAL and MESSAGES models (highlighted in pink and purple in Figure 2-1) (Hall and Buckley, 2016). While both prioritise cost minimisation as an investment decision support tool, they are not designed to model power systems. Analysis of transmission constraints in a net zero energy system necessitates models explicitly tailored for power systems. EnergyPLAN is one such software used in other studies (Connolly *et al.*, 2011; Meschede, Child and Breyer, 2018; Dorotić *et al.*, 2019). PyPSA is an open-source model package based on the Python language, which has capability to optimise unit dispatch, transmission constraints and integration of other sectors. It has primarily been used to model electricity and heating coupled markets for the Europe (Zhu *et al.*, 2019, 2020). Additionally, TIAM-UCL is a global optimisation model derived from the MARKAL model as a technology-rich bottom-up cost optimisation model (Anandarajah *et al.*, 2011).

More recently, other models have been developed from this basis. The PyPSA framework has been used to develop a global energy systems model based on OSM data. This uses another package called Synde, but it was highlighted that its performance was generally worse in low income countries due to data availability issues (Parzen *et al.*, 2023). The highRES framework was designed to complement the TIMES (a successor of MARKAL) modelling framework but integrating a higher resolution of renewable energy dispatch and network constraints to better understand issues around renewable integration and flexibility (Price and Zeyringer, 2022). It does not however consider interlinkages with other energy markets such as hydrogen. The WeSIM model has been used to develop cost-effective pathways for the decarbonisation of heating, both as a standalone model to assess heat networks (Dehghan *et al.*, 2024) and also soft linked with a resource technology network model to consider hydrogen technologies (Aunedi *et al.*, 2022). Like many other energy systems models, it includes demand as an exogenous input based on other values, but does not consider it as part of the cost-optimisation process.

Review of multiple energy systems models has highlighted that irrespective of their model structure, they can share common challenges that further development could address. One is capturing the behaviour of individuals and the choices regarding their energy use (Prina *et al.*, 2020). Another highlighted that modelling demand is a challenge for many, with it usually being treated as an exogenous input rather than as part of the model (Chang *et al.*, 2021). Interlinkages of modelling approaches and timescales is also computationally complex. A review of 75 modelling frameworks found that PLEXOS was one of the only software packages that could automatically combine analysis of power systems with longer term investment optimisation (i.e. the hard-linking of long - and short-term models) needed to optimise a net zero technology portfolio (Ringkjøb, Haugan and Solbrekke, 2018).

2.1.3 The role of diversity and transmission constraints

Renewable generation (mainly wind and solar PV) is anticipated to provide a significant proportion of final energy worldwide by 2050, so managing intermittency will be increasingly important (IEA, 2022b). Diversity can play an important role in this. As the timing of intermittent generation cannot be controlled without flexibility measures, other aspects such as reduced balancing requirements, less extreme highs or lows of generation, and reduced strain on transmission networks should be considered.

Geographic diversity improves renewable supply consistency. Distance between renewable generators reduces the correlation of intermittency, enhancing supply stability and reducing forecasting errors (Sinden, 2007). For wind, the correlation tends to below 0.1 at distances >1000 kilometres - approximately the length of the mainland UK. Geographically diverse generators can mitigate the "self-cannibalization" effect, where electricity prices decline and/or experience substantial fluctuations during periods of peak generation, i.e. during strong winds (Odeh and Watts, 2019). This can lead to negative prices, where generators bid at a price equal to marginal cost minus the strike price to avoid costs associated with not generating power (Baringa, 2015). This volatility, observed for the first time in the UK in May 2019, is anticipated to intensify with growing renewable capacity (Stoker, 2019). Improved consistency of supply would reduce the need for more expensive balancing actions or additional flexibility, which should reduce overall costs.

Generator diversity can also contribute help reduce costs and improve the security and resilience of an energy system. In the UK, modelling technology combinations found the least-cost options might compromise security or emissions, whereas combinations of technologies would be more suitable overall (Pfenninger and Keirstead, 2015). Avoiding over-reliance on wind and solar for the bulk of renewable generation could improve system resilience without increasing cost. Modelling technology portfolios for Scotland found that marine (wave and tidal) capacity could reduce the portfolio risk at the same cost (Allan *et al.*, 2011). Modelling of tidal current devices has shown potential under-valuation of improved predictability, emphasising the value of technology diversity (Lewis *et al.*, 2019). Therefore, a diversified mix, not solely reliant on wind or solar PV could benefit energy systems beyond cost considerations. In the UK, recent reinstatement of CfDs for onshore wind (but also a new category for “remote island wind”) and separate category for tidal current (BEIS, 2020a) demonstrates that this importance has been recognised.

Electrical transmission capacity is key to maximising the benefits of geographic and supply diversity. Enhancing links between the UK and France could facilitate improved utilisation of renewables, reducing CO_2 emissions and operational costs (Pean, Pirouti and Qadrdan, 2016). Interconnections could facilitate counter-trading between the UK and Ireland, helping to reduce renewable curtailment (Higgins *et al.*, 2015). For islands particularly, interconnections are essential to maximising the benefits of renewables (Zafeiratou and Spataru, 2018). In summary, supply and geographic diversity could benefit both volatile energy markets and the grid by increasing the consistency of renewable generation and decreasing CO_2 intensive balancing actions - provided there is sufficient transmission capacity available.

2.2 Modelling demand for a net zero energy system

Demand-side strategies for the net zero energy transition have been relatively overlooked compared with supply-side adaptations (IPCC, 2022). While achieving net zero targets solely through switching emissions-heavy capacity for low-carbon generation is theoretically possible, it would result in a much larger and more expensive energy system - estimated at up to 4 times larger than today for the UK and heavily dependent on yet-unproven carbon capture, storage, and utilisation (CCUS) technology (Barrett *et al.*, 2021).

Minimising demand can have “multiple benefits” for the overall system, consumers, and network operators. Reducing peak demand can lower system costs and emissions but reduce also the need for extensive grid infrastructure and expensive balancing actions, while improving security by reducing reliance on energy imports. Moreover, it has health benefits of improved thermal comfort, cleaner air, and savings on bills for households and businesses. In the context of more complex, interconnected, and digital net zero energy systems, the value of these benefits is likely to rise (IEA, 2015).

Considering demand alongside intermittent renewable generation requires a high-temporal resolution model to also capture demand fluctuations. However, review of UK energy systems models found that the majority have treated demand as an exogenous input (Hall and Buckley, 2016). Capturing all sectors of demand will be essential as energy demand from fossil fuels is replaced with other energy types. This section will summarise the structure of demand models, how time use data has been used to address challenges facing such models, and how they can be used to project estimates of demand towards net zero.

2.2.1 Demand model structures and data sources

Demand models can also be either top-down (macroscopic economic forces) or bottom-up (engineering calculation of individual contributions). Traditionally, due to the heterogeneity of sectors, technologies, and data availability, demand modelling has focused on sectors separately, with a particular focus on the domestic sector given the homogeneity and accessibility of data (Sousa *et al.*, 2017).

However, more recent models have covered a wider range of sectors, with greater resolutions. The Centre for Research into Energy Demand Solutions (CREDS) developed a demand reduction model based on scenarios encompassing the entire UK energy system. This integrates bottom-up scenarios by sector with top-down cost optimisation in UK TIMES. It considered peak demand for energy system sizing, but acknowledged that a more detailed analysis could be achieved with an hourly model (Barrett *et al.*, 2021). Incorporating an hourly model with a growing share of intermittent renewables is crucial to examine of the interaction of demand with shorter-term weather patterns.

In any demand model, it is critical to consider the data required to statistically represent modelled sectors. Historically, archetypes have been used to represent the main categories of demand users which are statistically representative (Sousa *et al.*, 2017). More detailed data and improved desktop computing power has allowed models to sample 100% of the population without categorising demand into potentially restrictive archetypes, eliminating potential sampling bias (Hamilton *et al.*, 2013).

The Dynamic Energy Agents Model (DEAM) considers activity patterns and weather to model hourly energy demand for services, residential, transport, and industrial sectors, at the distribution network level in the UK. This model relies on a "100% sample" and standardised behaviour profiles (Spataru and Barrett, 2016). The 3DStock framework was used to create a database of London buildings, focusing on complex and mixed-use properties and a 100% sample to eliminate sampling bias. Heating demand was modelled with standardised occupancy profiles using the SimStock framework, which generates an EnergyPlus input file to calculate heating demand (Steadman *et al.*, 2020). In a study for developing countries, an hourly model for both domestic and non-domestic demand of the 14 West African Power Pool countries emphasised the challenges of lacking country-specific occupancy profiles in developing countries (Adeoye and Spataru, 2019).

Addressing the heterogeneity of human behaviour is highlighted as crucial. At higher temporal resolutions, relying on standardised, one-size-fits-all occupant behaviour assumptions may not align well with observed data. Comparison between the standardised assumptions in the BREDEM model (widely used in the UK to calculate annual energy demand, particularly for EPC ratings) and a national survey found over-heating in the standard method (Huebner *et al.*, 2013b). Measured room temperatures varied significantly above and below the assumed 21°C in BREDEM, underscoring the diversity of human behaviours which drive energy demand but also how the effects of energy efficiency measures could be overestimated if compared to the EPC/BREDEM benchmark (Kane, Firth and Lomas, 2015). More accurately capturing human activity and the contributing factors which affect it within demand models could therefore enhance the accuracy of existing models.

2.2.2 Time use data and factors influencing demand

Time use data offers a means of capturing both demographic characteristics of a population and developing high-temporal-resolution energy profiles without recording specific data. The openness of the data allows privacy concerns facing smart meter data to be circumvented (Grünewald and Layberry, 2015). Time use data documents the daily activities of several thousand participants in ten minute intervals and combines with extensive demographic data (Gershuny and Sullivan, 2017). The detail of actions means they can form energy demand and building occupancy profiles (Torriti, 2020). Combined with census data to generate a synthetic population matching the statistical distributions of the actual population, the most relevant time use behaviour and energy profiles can be selected to mirror the energy demand of the actual population (Thorve *et al.*, 2019). It has been widely used for energy modelling in countries including Japan, Sweden, Italy, Ireland, France, and Spain (Torriti, 2020).

However, despite time use data capturing the actions and locations of individuals throughout their day (e.g. home, shopping, work, and travel), it has almost exclusively been used for the domestic sector. There is limited evidence of time use data being used for non-domestic or combined energy demand models in the literature, with the exception of electric vehicle charging patterns (Dixon and Bell, 2020).

Models will never perfectly represent reality but should instead capture the most important characteristics of the phenomenon being studied. This means understanding which aspects of human behaviour are important at the relevant spatial and temporal resolutions, and how this dictates what data is selected for a given region. An analysis of annual household energy demand has revealed that building-related factors can explain 39% of the variability, socio-demographic variables 24%, and heating behaviour 14% (Gesche M. Huebner *et al.*, 2015). Regarding demographic factors, household size and income have consistently emerged as the most influential variables on annual energy demand (Druckman and Jackson, 2008; Gesche M. Huebner *et al.*, 2015; Antonopoulos, Trusty and Shandas, 2019).

However, at an hourly resolution, factors such as household composition and employment status have a more significant effect, influencing whether individuals are away from home, such as being at work or school (Intertek, 2012). These influences on behaviour and energy demand are well-captured by time use data, especially considering the number of individual (604) and household (335) demographic variables in the UK (Gershuny and Sullivan, 2017). Combined with the discussed discrepancies between assumptions about heating profiles assumed in BREDEM (Huebner *et al.*, 2013a), time use data could be suitable for improving the issue of human behaviour in energy modelling, particularly integrated with a whole energy systems model.

2.2.3 Estimating net zero demand: policies and sector changes

Achieving net zero will require energy demand to be met by alternative technologies and could require changes to how demand is treated in energy markets. The extent of this change will be dictated by technology suitability, deployment rates, public acceptance, and others. These need to be captured by a demand model to understand how these interact with the whole energy system and compare them with other investment decisions. The broad and interdisciplinary advantages of energy efficiency complicates their evaluation considerably compared to generation, against which investment decisions could be considered (IEA, 2015).

In addition to annual demand, one must consider factors like peak demand, the timing of energy demand, ramp rates, flexibility, impact on bills, and the ability of households and businesses to invest in measures (with or without policy support). The available technologies for reducing demand differ in energy-saving potential, initial capital outlays (and their distribution), and supplementary benefits (again - their distribution). All these elements combine in considering cost-effectiveness, yet this hinges on the perspective adopted and the boundary of the benefit system from which calculations are made (Yushchenko and Patel, 2017).

The cost-effectiveness of a measure can depend significantly on the specific technology and the definition of the boundary (i.e. which stakeholders are considered) when assessing benefits. This exerts an influence on the scope and nature of policy support considered suitable, considering the distribution of costs and benefits (Molina, 2014; Rosenow and Bayer, 2016; Cho *et al.*, 2019; Streicher *et al.*, 2020). To compare energy efficiency measures and policies effectively, methodologies must be employed that encompass a wide array of stakeholders and technology characteristics.

Studies have explored various technologies, but there is a particular emphasis on building energy efficiency. EPC data has been central to modelling this, but the predictive performance of the models used to calculate energy demand (the main determinate of the EPC rating) has been shown to be poor due to range of factors. The energy demand models are relatively outdated, the assumptions about occupancy behaviour are been shown to be inaccurate and lacking diversity, and there are questions on the consistency of data gathered by assessors (Organ, 2021). The “performance gap” has highlighted that highly EPC rated buildings tend to use more energy than expected, while low EPC ones use less due to over- and under-heating respectively (Cozza, Chambers and Patel, 2020). Despite this, it is in many European countries the most comprehensive source of building fabric data available, so has been used to model the cost-effectiveness and consequences of policies in Finland (Niemelä, Kosonen and Jokisalo, 2017), Italy (Pagliaro *et al.*, 2021), UK (Ben and Steemers, 2020), Portugal (Palma, Gouveia and Barbosa, 2022), and Ireland (Coyne and Denny, 2021). There is still a clear correlation between recorded energy demand reducing with improved EPC ratings (McKenna *et al.*, 2022). To avoid the issues regarding the energy model methodologies, studies have focused on using the underlying fabric data instead.

Heat pumps are considered essential to the decarbonization of heating, due to efficiency and the reduction of peak demand. In colder climates, peak demand, and consequently, overall system cost is predominantly influenced by heating (Watson, Lomas and Buswell, 2019). Analysis of heat pump deployment in the UK has revealed that while annual heating demand may increase by up to 8% compared to gas boilers, peak demand can be reduced by 8%, and the maximum ramp rate can be reduced by as much as 67% (Watson, Lomas and Buswell, 2021). Heat pump adoption will be significantly shaped by policy support mechanisms, such as the incorporation of climate policy costs into electricity prices and the provision of direct financial incentives. Additionally, the synergies between upgrades in building efficiency and the deployment of heat pumps are considerable (Kokoni and Leach, 2021).

Anticipated changes in technologies and the electrification of various demand sectors are expected to reshape the requirements of a net-zero energy system. The increase in electricity demand for heating and electric vehicles is projected to be the primary driver of peak demand growth, with a more modest increase in annual energy demand in Germany and the UK (Bobmann and Staffell, 2015). To mitigate the surge in peak demand, measures like reducing temperature-related inefficiencies in electric vehicle charging, expanding charging infrastructure (Lindgren and Lund, 2016), and increasing battery capacity (Dixon and Bell, 2020) could be instrumental. In the significant demand sector of industry, a substantial 79% of energy efficiency initiatives are not tailored to any specific industrial sector (Safarzadeh, Rasti-Barzoki and Hejazi, 2020). The complexity of bottom-up modelling for industrial energy efficiency arises from the heterogeneity of sectors and technologies (Fleiter, Worrell and Eichhammer, 2011)

While most models consider annual savings of individual sectors, fewer compare the potential savings across all sectors. Considering system demand data and individual load profiles for lighting, water heating, and cooling revealed substantial variations in the time-value of different measures, with notable advantages for reductions in greenhouse gas emissions (highest during peak demand), diminished requirements for generation capacity, and decreased stress on network infrastructure (Mims, Eckman and Goldman, 2017). An investigation of hourly domestic, commercial, industrial, and public demand patterns in Brazil demonstrated that employing lower temporal-resolution modelling might be sub-optimal (Pina, Silva and Ferrão, 2011). Modelling hourly building demand in the United States underscored the crucial need for time-sensitive evaluations of energy savings to fully harness the benefits of efficiency and flexibility (Satre-Meloy and Langevin, 2019). Clearly, the assessment and quantification of the varied benefits of energy efficiency, especially in terms of overall energy system costs, can be significantly enhanced with higher resolution modelling. To capture all these advantages and make meaningful comparisons of savings potential across sectors, a whole energy system model is needed.

2.3 Bioresources energy potential characterisation

The increased complexity of net zero energy systems creates opportunities to maximise synergies with other sectors. Incorporating circular economy principles and improving resource efficiency could play a major role in reducing waste and greenhouse gas emissions (Seljak, Baleta and Mikulčić, 2023). The utilisation of bioresource waste presents an opportunity to alleviate the competition that traditional biomass has with other land use demands, whilst also addressing wastage of water, land, nutrients, and energy-through-waste going to landfill (Ingrao *et al.*, 2018). Currently, within wider energy systems modelling, few incorporate this potential, which could result in a more optimal overall achievement of net zero targets.

2.3.1 Assessing the availability of biowaste

Biowaste is characterised by its heterogeneity. Resource types have differing characteristics, production methods, and potential uses. Assessments of biomass resources for energy have focused on a specific industry or waste streams (Lora Grando *et al.*, 2017), considering in detail a single resource or industry. The whisky industry has been a particular focus of energy potential studies (Meadows and Strachan, 2015; Clearfleau, 2016; Barrena *et al.*, 2018a; White *et al.*, 2020), but also farming (Rural Futures, 2010; Kassem *et al.*, 2020) and food processing (Hung, Show and Tay, 2005; Teigiserova, Hamelin and Thomsen, 2019). Individual studies such as these are better able to capture the sector-specific factors which influence the characteristics and processes of converting biowaste into energy.

On the other hand, some models have taken a broader approach by encompassing multiple waste types to explore synergies between sectors, including cooperation on legislative and policy issues; costs reductions; improved environmental outcomes; and energy output (Song *et al.*, 2016; Keller *et al.*, 2019; Hoo, Hashim and Ho, 2020). The initial action of the REPowerEU plan emphasises increased stakeholder cooperation to maximise biogas production and share best practice (European Commission, 2023b), highlighting how maximising the utilisation of bioresources requires a cooperative, systems-orientated approach.

The significance of co-digestion, where multiple types of waste are digested together, has received growing attention (Lora Grando *et al.*, 2017). Review of co-digestion papers found the co-digestion performance index (the ratio of the averaged biogas production to the co-digested biogas production; a value >1 indicating that co-digestion outperforms mono-digestion) of various waste products (such as food waste, dairy manure, oat straw, toilet paper and crop residues) varied from 1.0-1.9. As improved yields through co-digestion have only been demonstrated in the laboratory, full scale, continuous-flow trials are needed to fully demonstrate the potential (Karki *et al.*, 2021). Consideration of a wider range of biowastes clearly has potential to optimise their overall utilisation.

2.3.2 Modelling waste collection costs

In contrast with other waste types like dry domestic waste for incineration, the moisture content of biowastes for anaerobic digestion make them unsuitable for prolonged storage (Lü *et al.*, 2016). For distributed waste streams, such as domestic or commercial food waste, transportation is a critical factor. Waste collection costs make up approximately two-thirds of the total operational costs of domestic waste management, mainly for staff and vehicle fees (WRAP, 2015). Despite this, costs for transport in the anaerobic digestion literature are treated as exogenous or calculated as a tonne-average (Luz *et al.*, 2015; Kassem *et al.*, 2020; El Ibrahimi *et al.*, 2021; Balcioglu, Jeswani and Azapagic, 2022). Uncertainties around participation rates, collection options, and costs have been highlighted as challenging for food waste collection (WRAP, 2021). Therefore, modelling of transportation costs could significantly impact the assessment of biowaste in modelling of co-digestion.

Numerous approaches have been developed to minimise distance or cost when directing vehicles between waste generation sites and collection depots within the constraints of vehicle capacity - known as the capacitated vehicle routing problem (CVRP). Employing a backtrack search algorithm along with a threshold waste level (indicating how full each waste node is), researchers observed a 37% decrease in travel distance for 91% of routes when compared to a simplified model (Akhtar *et al.*, 2017). Similarly, utilisation of a particle swarm optimisation algorithm to optimise routes resulted in optimal costs, travel distance, fuel efficiency, and waste collection efficiency at 70-75% of the threshold waste level (Hannan *et al.*, 2018). By utilizing the Google-developed OR-Tools CVRP solver and a recursive-DBSCAN algorithm for node clustering to reduce problem size, a 61% enhancement in runtime was achieved for problems involving up to 5000 nodes (while the basic solver could only handle <2000) with a minimal 7% decrease in accuracy (Bujel *et al.*, 2018). In these instances, CVRP solvers that take local topography into account can produce more specific estimations of waste collection costs compared to simpler heuristic or flat-rate approaches.

To optimise the CVRP for various metrics such as cost, time, or distance, a matrix of distances between nodes is used. In some studies, the straight-line, Euclidean distance between nodes is used (Edwards *et al.*, 2016; Bujel *et al.*, 2018). For major cities, an acceptable compromise was found by adjusting the distance using a factor of 1.3. However, it was emphasised that this approach is more suitable when a lower proportion of nodes are served in the network, which may not hold true when considering household food collection (Boyacı, Dang and Letchford, 2021). To improve on the limitations of the straight-line distance approximation, a Python package called Open Street Map Network (OSMnx) utilises data from Open Street Map (OSM) to provide actual road networks for distance and travel time calculations (Boeing, 2017). OSMnx has been applied in various studies, such as comparing waste collection route optimisation methods in Salvador, Brazil (Oliveira and Garcia, 2021); assessing the potential of heat from waste water in Göttingen, Germany (Pelda and Holler, 2018); and genetic algorithm waste collection optimisation tool for Lisbon, Portugal (Da and Mendonça, 2018). This package combined with CVRP solvers can therefore be used to provide more specific costs for waste collection, which combined with other waste optimisation frameworks would improve understanding of how critical waste collection costs are to the overall cost of energy from waste.

2.3.3 Frameworks to optimise energy from waste

Analysis of transport costs could be incorporated with other optimisation frameworks, which commonly compare facility configurations and technologies. These influence the amount of useful energy and so overall cost, which determines the impacts and benefits of waste-to-energy projects. The ranking of outcomes depends on assessment metrics, which vary with desired objectives or end-users' preferences (Duguid and Strachan, 2016; Hoo, Hashim and Ho, 2020). Moreover, the availability of resources (which could be constrained by transport costs) is a primary factor influencing the sizing of digestion projects (Luz *et al.*, 2015; Kassem *et al.*, 2020; Balcioglu, Jeswani and Azapagic, 2022; Castley *et al.*, 2022). Frameworks used to assess biowaste-to-energy include:

(i) S*tochastic programming:* applied to municipal solid waste for Singapore, demonstrated that an optimised hybrid waste-to-energy system could be more viable than the current incineration system (Xiong, Ng and Wang, 2016).

(ii) *Input-output modelling:* comparing five waste-to-energy technologies and multiple waste-streams demonstrated that wastewater biogas and solid waste incineration was the most best, mitigating up to 18 $MTCO_2$ (Song *et al.*, 2016).

(iii) *Life-cycle assessment and life-cycle cost models:* for agricultural waste in Turkey highlighted the impact of higher biogas yield waste streams on natural gas. In most cases, waste streams with higher biogas yields showed significant improvements over natural gas, while materials with lower biogas yields offered more limited benefits (Balcioglu, Jeswani and Azapagic, 2022).

(iv) *Bio-inspired optimisation algorithms:* particle swarm optimisation using cost, energy, and carbon savings metrics for combined heating, cooling, and power systems, found an integrated anaerobic digestion and biogas boiler setup resulted in the most savings. Results were however influenced by metric weightings, which could vary depending on the end-user preferences (Castley *et al.*, 2022).

(v) *Techno-economic models*: modelling of a centralised distillery waste anaerobic digestion and energy facility on the Scottish island of Islay compared combined heat and power (CHP) and biogas boilers, with factors such as demand availability influencing the optimal technology choice (Duguid and Strachan, 2016). Study of municipal solid waste gasification for Brazilian municipality power generation demonstrated that larger plants with higher installed power could be more economically viable (Luz *et al.*, 2015). Additionally, a waste-to-energy model for dairy waste in New York state revealed anaerobic digestion and hydrothermal liquefaction were feasible with averaged collection costs, resulting in a net present value of $0.4-1.5 billion (Kassem *et al.*, 2020).

2.4 Case studies using PLEXOS

PLEXOS is an energy dispatch optimisation software, which can deal with several temporal and spatial scales (orange in Figure 2-1). It is an optimisation software which, given the techno-economic characteristics of various technologies, creates equations which are optimised - generally to minimise the overall cost of energy, in addition to other constraints. Its primary focus is the technical dispatch of energy (e.g. minute up to hourly) - although it can also optimise longer term investment decisions that can be interlinked between runs of the shorter term energy dispatch model (Energy Exemplar, 2023a), it focuses exclusively on certain energy sectors and does not have the same economy-wide flexibility as models like MARKAL. In addition to a user interface which can edit models manually, it also has an API in Python which enables setting up and running models to be automated (Energy Exemplar, 2023b). It has been widely used to model electricity markets (Table 2-1) but although it is freely available under an academic license, as a proprietary software it does have issues around repeatability or interpretability of methods and results (Oberle and Elsland, 2019).

The main strength of PLEXOS is optimising electricity dispatch with transmission constraints (Energy Exemplar, 2023a), which was identified as being crucial to capturing the weather dependent effects of a renewable energy dominated generation system (Section 2.1.2). It is also capable of modelling interlinkages between electricity and other energy markets, such as natural gas and/or hydrogen (Ahern *et al.*, 2015; Zappa, Junginger and van den Broek, 2019; Moran *et al.*, 2023). Its can also optimise the dispatch of storage and DSR in relation to electricity prices (Tomšić *et al.*, 2020), which will both be key technologies in achieving energy system decarbonisation (National Grid, 2023).

While PLEXOS excels at the short and long term dispatch of energy, it is however less capable at modelling demand (Section 2.2) or the potential for other energy vectors (such as biowaste - Section 2.3). In the cases described in Table 2-1, demand influenced by changing technologies and the potential integration of biowaste is included as a separate input. However, it will be crucial to fully understanding net zero by including the widest range of technologies and their interactions with the overall system (Section 2.1). This requires either soft- or hard-linking of other models with PLEXOS. This integration is essential in understanding their contribution to decarbonisation.

Table 2-1: Sample of models using PLEXOS.

Reference	*Sectors*	*Region*	*Timespan*	*Key findings*
(Diuana, Viviescas and Schaeffer, 2019)	Electricity	Southern Brazil	2030/2050; hourly	Higher penetrations of wind and thermal balancing in the hydropower-dominated system could reduce costs and improve system balancing.
(Adeoye and Spataru, 2018)	Electricity	West Africa	2025; hourly	High integration of solar PV could minimise load shedding and help meet growing demand
(Higgins *et al.*, 2015)	Electricity	Ireland/UK	2016; hourly	UK-Ireland interconnections allowed for 5% more Irish wind capacity, less curtailment and a lower cost of energy.
(Tomšić *et al.*, 2020)	Electricity, transport	Croatia	2015-2050; hourly by 5 years	Flexibility from electric vehicles could have synergies with renewable generation, but also affect peak demand.
(Ahern *et al.*, 2015)	Electricity, hydrogen, transport	Ireland	2030; hourly	50 MW of hydrogen capacity combined with anaerobic digestion methanation could provide up 19.1% of Ireland's transport demand, whilst reducing wind curtailment.
(Baringa, 2013)	Electricity	Scottish islands	2020, 2025, 2030; hourly	Island wind could receive a 4% higher electricity price than onshore or offshore wind, with generation diversity decreasing intermittency costs for the whole UK.
(Moran *et al.*, 2023)	Electricity, hydrogen	Spain/ Ireland	2030; hourly	Grid-based hydrogen production can have the lowest cost of energy, which low-cost storage can be essential to.
(Zappa, Junginger and van den Broek, 2019)	Electricity, heating, transport, industry, hydrogen, biogas	EU	2050; hourly	100% renewable system would be possible but requires significant biowaste utilisation for balancing and 240% more transmission capacity.
(Herc *et al.*, 2021)	Electricity, heating, transport, industry, hydrogen	Croatia	2050; hourly	Uses PLEXOS to validate the results of a similar open-source software package for modelling net zero energy systems.
(Béres *et al.*, 2024)	Electricity, heating, hydrogen, industry, transport	EU	2050; hourly	Links PLEXOS with the JRC-EU-TIMES model to analyse how indirect electrification like hydrogen production influences renewable energy use, system flexibility, and reliability in the power sector
(Frew *et al.*, 2023)	Electricity, hydrogen, exogenous demand	Eastern USA	2026, 2030, 2034; hourly	Traditional price-taker models overestimate nuclear-hydrogen system benefits, but hybridization can still be profitable when accounting for hydrogen storage constraints and power system impacts.

2.5 Modelling decarbonisation policies in the UK

To inform the structure and focus of subsequent modelling work, net zero policy in the UK and Scotland is reviewed here. A brief overview of the legal framework is provided, followed by summary of key sectors and policies, illustration of the uncertainty inherent to strategy, and relation with circular economy policy.

2.5.1 Structuring of net zero legislation

In 2019, the UK became the first major country to legislate for net zero by 2050, which (not to be outdone) was upgraded to 2045 in Scotland (Scottish Parliament, 2019a). In the 2021 Net Zero Strategy, the UK Government has since set targets which would have been unthinkable a decade ago, such as total electricity generation decarbonisation by 2035. Net zero is legislated through the Climate Change Act, which sets out legally binding five year carbon budget periods to measure progress (UK Government, 2021). This allows the progress of the Government in meeting targets be challenged in court, as occurred in 2023 (UK Government, 2023). The High Court ruled that targets lacked implementation detail and required an updated strategy to be published. As of October 2023, the original claimant argued that the updated strategy only accounted for 95% of the sixth Carbon Budget (2033-2037), and so would again take the Government to court (ClientEarth, 2023).

The Climate Change Committee (CCC), a cross-party panel which advises Parliament on the Governments net zero progress, has also interrogated government plans. Its most recent report highlights selective progress, such as EV sales and developing dispatchable, low-carbon generation, but that more efforts are needed in areas like electrification of industry and heat pump deployment. Energy efficiency is a particular area of “low-regret” potential in which policy is lacking (CCC, 2023), which could have numerous benefits for consumers, network operators, businesses, and the whole system (IEA, 2015). Another is the issue of strategic planning for waste (CCC, 2023), which is the responsibility of DESNZ and DEFRA. Clearly, although the Government has made considerable steps towards net zero in setting targets in certain areas, there are others in which there is room for improvement. Fulfilling the goals on time will present further challenges.

2.5.2 Net zero strategy and specific policies

The UK Government's plans for achieving its legally binding net zero target are outlined in several key documents. The main of these is the Net Zero Strategy (UK Government, 2021), but this has also been updated more recently in the Powering up Britain report, which focuses on energy security and opportunities for growth in net zero (DESNZ, 2023i). There are other sectoral-specific plans for hydrogen (DESNZ, 2023g) and biomass (DESNZ, 2023a), but no specific plan for demand, which instead forms a chapter of the energy security report in Powering up Britain (DESNZ, 2023i).

Table 2-2: A sample of headline net zero policies in the UK (DESNZ, 2023i).

Type	*Sector*	*Description*	*Target year*
Supply	Generation	At least one CCUS power plant	Mid-2020s
		50 GW offshore wind	2030
		10 GW hydrogen production	2030
		Power sector decarbonisation	2035
		24 GW nuclear	2050
Demand	Industry	6 $MtCO_2$ CCUS annually	2030
	Buildings	30% lower emissions in new homes standard	2025
		Up to £1 billion to improve least efficient households	2026
		600k heat pumps installed annually	2028
		15% energy reduction from 2021	2030
		75% reduction in public sector emissions	2037
	Transport	Internal combustion engine ban	2030
		10% sustainable aviation fuel mandated	2030
		Half of city journeys to be walked or cycled	2030
		EV charging funding	Various

Looking at a high-level sample of UK net zero policies (Table 2-2), ostensibly several sectors are addressed. On the supply side, with fewer technology options there are generally fewer specific policies. Given the wider range of sectors, demand side policies have a greater spread. Unlike the clear targets for supply sectors, demand goals tend towards ambitious targets lacking clear pathways to achievement - i.e. building 50 GW of offshore wind is clearer than a 75% reduction in public sector building emissions. A clear vision for network capacity improvements needed to transmit additional generation is also lacking, with transmission investment failing to keeping pace with generation (Helm, 2023). The focus is still also very much on large-scale, transmission connected generation - distributed generation hardly features in the report and onshore wind is still effectively banned in England (Staffell *et al.*, 2023). Although the nuclear plans feature so-called "small" modular reactors (SMRs - a technology which has yet to be demonstrated), they are still at least several hundred megawatts (Matthew and Walker, 2022).

Few policies have clear targets for demand-side flexibility (aside from the push to install smart meters) despite potential benefits for grid stability. Commitment to storage is also lacking, perhaps being assumed that hydrogen will be able to provide flexibility and storage at a range from seconds up to months. Balancing renewable generation without fossil fuels will require greater storage capacity. In the most recent parliamentary review of the Government's net zero policies, the CCC found demand policies tended to have significant or some risk involved. Without remedial action or contingency plans, it seems unlikely that many targets will be met (CCC, 2023). Other studies have highlighted a lack of coherent demand strategy (Barrett *et al.*, 2021; Johnson, Betts-Davies and Barrett, 2023).

In terms of a trade-off between supply and demand; the traditional large-scale, centralised, transmission-heavy paradigm and the smaller-scale, distributed, digital potential, there is not clear picture of what an optimal net zero energy system looks like. In the case of UK policy though, focus is clearly on the former, which could be to the detriment of the latter. Considered as a complex system, policymakers are subject to "bounded rationality" in which they are unable to process all the relevant information (Robertson Munro and Cairney, 2020). Fixation on specific options could exclude the other potentials. Digitalisation of demand and distribution of supply creates opportunities for net zero networks to have greater flexibility and resilience. Organisational structures like Energy Communities could help to improve the acceptability of energy infrastructure though reducing bills; combatting energy poverty; reducing transmission losses and congestion; leveraging flexibility; and increasing competition (Manso-Burgos *et al.*, 2022). The public acceptance of low carbon technologies, whether large scale infrastructure such as wind farms and transmission infrastructure, or distributed technologies like heat pumps, will be crucial in achieving intermediate targets and the ultimate goal of net zero. Research of the complexity of energy policy has highlighted that government policy can facilitate changes, but not guarantee its achievement. Responsibility needs to be shared with local participants to improve chances of success (Robertson Munro and Cairney, 2020). Therefore, it will be essential for modelled scenarios to consider this trade off and compare potential policy commitments.

Opportunities to harness smaller-scale solutions are however hardly discussed in Government plans or policies, in contrast for example with the EU, which has legislated for and set up a hub for communities to share best experiences setting up their own energy projects (European Commission, 2023a). Developing a net zero energy system need not just be about finding the least-cost solution, but about creating a more resilient, inclusive, and mutually beneficial system for consumers and the environment. Framing of energy policies as seeking public approval, such as affordability and security for energy efficiency, rather than 'illusory, control-based' approaches', have been highlighted as potentially more successful for imperative net zero targets (Robertson Munro and Cairney, 2020).

Technologies like domestic solar PV are now much less supported by Government with ending of the FiT - ostensibly due to the argument that the market is now mature and self-sustaining (BEIS, 2018c). Research has shown though that without specific support, the benefits of low-carbon technologies most frequently go to those well-off enough to afford them (Stewart, 2021). Other schemes like ECO offer support for home generation, but their deployment is less than 10% of its peak in 2014 (CCC, 2023). While net zero can indeed be facilitated and sped up through market economics in some ways such as bringing down the cost of technologies, leaving it entirely up to the "market" will simply encourage the least cost option whilst avoiding any risk which is inherent in adopting new technologies that will be needed (Christophers, 2024). Addressing the issues raised by citizens Climate Assembly could help to minimise the implementation risks in meeting technology specific targets (Elstub *et al.*, 2021) - missing individual targets will only push back the date net zero is achieved.

Instead, the UK Governments net zero strategy relies on unproven technologies - particularly nuclear and CCUS. While older, gigawatt-scale nuclear is technically possible, its ability to deliver on budget and on-time is questionable, and any new large nuclear power stations beyond Hinkley and Sizewell are unlikely to be ready by 2050. Newer, (relatively) smaller technologies are being designed to address this, but seem unlikely to deliver any more convincingly or affordably in time (Matthew and Walker, 2022). CCUS, which would facilitate continued reliance on natural gas, could be feasibly possible but has not been demonstrated at scale. The best supported use-cases for the technology are likely hard-to-decarbonise industries, but in other options it remains unclear whether it should play a role relative to the significant fall in costs for renewable and storage technologies (McLaughlin *et al.*, 2023). This is further demonstrated by the Government's insistence one being on of the few countries in the world to even consider hydrogen for home heating, despite the abundance of expert opinion against it (Rosenow, 2022). Again, all these technology options reinforce the traditional, thermal-heavy, top-down energy system.

2.5.3 Uncertainty in pathways to net zero

The uncertainty in the UK around the structure of a net zero energy system is illustrated by comparison of National Grid's Future Energy Scenarios (FES). These are annual updates of potential net zero pathways from the network operator for varying technology combinations and policy decisions. They provide a holistic view of decarbonisation for all energy sectors (including their interaction) based on publicly available scenarios of technology deployment, policies from the CCC, and stakeholder engagement (National Grid, 2023). The nature of the scenarios assessment however makes them dependent on assumptions made, particularly regarding the prices of technologies and future technological developments which are hard to predict. The scenarios based nature also lacks probabilistic assessment, leaving the decision about optimality up to the reader, and making uncertainty analysis harder to conduct from results. The linear structure of how scenarios evolve over time might also neglect the non-linear way in which markets develop, particularly under periods of stress (e.g. the energy crisis) or abrupt policy changes. This being said, it is updated annually to reflect changes in policy, technology development directions, and expert opinions in relevant fields.

Comparing the potential ranges of generation technologies for 2019 (National Grid, 2019b) and 2023 (National Grid, 2023), Figure 2-2 demonstrates the scale of change in just four years. Combined wind and solar PV capacity has tripled from 79 GW to 249 GW; peak system demand increased by two thirds from 68 GW to 114 GW; and the potential range of thermal generation (biomass, bioenergy with carbon capture and storage [BECCS], hydrogen, and unabated fossil fuels) has increased from 22 GW to 74 GW. Due to ongoing delays, nuclear is the only technology with a reduced range in 2023. Rather than predict outcomes, these ranges highlight the plurality of pathways to net zero, whilst taking a technology neutral perspective driven by shifting government policy. Despite this, the scale of the swing in capacity in just four years demonstrates the uncertainty around net zero in the UK. This only considers electricity generation, let alone other energy types like hydrogen.

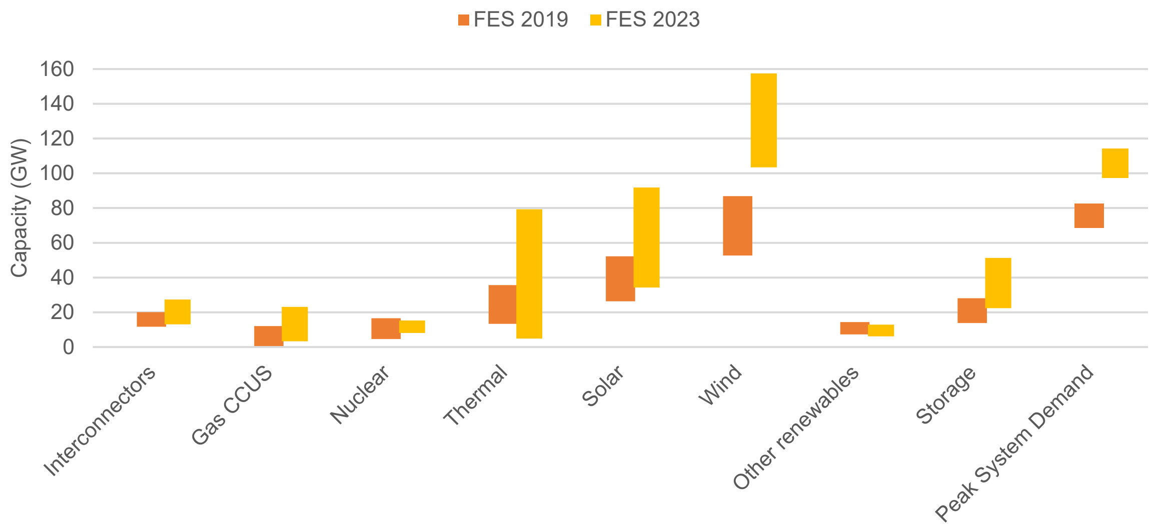

Figure 2-2: Comparison of generation capacity and peak demand for FES 2019 (National Grid, 2019b) *and 2023* (National Grid, 2023). *Thermal here includes hydrogen, unabated biomass, BECCS and unabated fossil fuels.*

2.5.4 Net zero and the circular economy

The circular economy is mentioned by the Government's net zero strategy in several ways, such as the importance of improved resource utilisation to reduce emissions, add value, and minimise waste (UK Government, 2021). Although also recognised in the Biomass Strategy (DESNZ, 2023a), there are few specific policies supporting the circular use of bioresources. Only the Green Gas Support Scheme (supporting projects exporting biogas to the network), the Smart Export Guarantee (a fixed rate for exporting electricity to the grid), Renewable Transport Fuel Obligation (requiring that an increasing percentage of transport fuels are renewably sourced) and CfDs (resulting in only six biomass projects in all six rounds) (Low Carbon Contracts Company, 2023) are still open for new applicants (DESNZ, 2023a). With the closure of the domestic and non-domestic Renewable Heat Incentive (RHI), support is therefore limited to projects generating electricity, exporting to the gas network, or producing transport fuel. Various issues are highlighted to reduce waste in England's Waste Prevention Programme, but synergies with other net zero sectors are barely mentioned (DEFRA, 2018). Specific policies targeting the synergies between circular economy sectors and energy systems are clearly lacking, reducing the chances of overall system optimisation.

2.5.5 Net zero modelling by Government

The UK Government publishes details on (publicly shareable) models deemed business critical (BEIS, 2022b). Analysis based on these models is used in a variety of contexts to inform policy decisions, with each being suited to specific aspects of the energy system. To summarise some of the most widely used and relevant to this work:

- *(i)* *UK TIMES (UKTM):* based on the TIMES model generator, it is the main model used by the Government to inform net zero projections. It is a technology-rich, "perfect foresight" cost optimisation model from 2010 to 2060 which covers all UK emissions and energy sectors (UK Government, 2021).
- *(ii)* *Dynamic dispatch model (DDM):* a profit maximisation model simulating electricity generation markets and investment choices for generation and electricity networks based on exogenous annual demand (transformed into daily curves using heating degree days (HDD)), policies and market structures (BEIS, 2022a).
- *(iii)* *Energy demand model (EDM):* econometric analysis of historic data used to project demand by sector and fuel in 2,500 variables, aligned with DUKES and used as inputs of demand for other models (BEIS, 2019a).
- *(iv)* *Distribution networks model (DNM):* a combined power flow model and investment model is used to assess the costs of distribution network upgrades,

with inputs of exogenous demand, distributed generation, and DSR (BEIS, 2022a).

(v) *National buildings database (NBD):* ongoing development of a database of the whole UK domestic and non-domestic building stock using the 3DStock modelling framework, with building fabric, energy rating, and annual energy use validated by surveys (UCL Energy Institute, 2023).

(vi) *Hydrogen infrastructure tool:* a hydrogen transition tool with 57 regions used to optimise costs for specific hydrogen demand for heat (BEIS, 2022b).

Although it may be determined by other models (EDM and perhaps shortly the NBD), modelling by the Government mainly considers demand as an exogenous input, meaning there is no trade-off between investing in demand or supply side measures. In a way, this assumes that changing energy demand is outwith government control - instead, its main responsibility is ensuring sufficient supply to meet demand. Research considering demand reduction in more depth as a decarbonisation strategy has shown it could result in a more optimal energy system (Barrett *et al.*, 2021). Additionally, the main decarbonisation optimisation model, UKTM, uses 16 time periods (4 seasons with 4 intraday periods each) and a single node (albeit with disaggregated renewable generation). Greater resolution in the modelling of net zero (which is included in others like DNM and NBD) pathways could lead to alternative, more optimal solutions which might not be apparent at a national level.

Least-cost modelling of generation capacity for the UK using the UKTM model also does not consider limitations of deployment for each technology or interactions with hydrogen electrolysis (BEIS, 2020c). Given the dependence of some decarbonisation pathways on hydrogen electrolysis, renewable intermittency, and a position linking electricity and hydrogen markets, incorporating hydrogen into high-resolution electricity and network models is lacking in Government modelling. Improved modelling could help to understand the implications of green hydrogen production at scale and how it could affect electricity systems.

2.6 Scottish islands energy systems modelling

This section highlights existing work on modelling energy in the Scottish islands for demand, supply, and biowaste; as well as island characteristics to model.

2.6.1 Modelling of island energy balances

Energy modelling for the Scottish islands to date has focused mainly on audits for various islands. Assessments have focused on the energy potential for various energy sources (particularly wind or marine), demand, hydrogen, biowaste, or grid capacity. Studies of national renewable potential have highlighted the extent of the island resource (Halliday, 2011; Marine Scotland, 2011; The Crown Estate, 2012; Neill *et al.*, 2017). Specific study of the islands identified a potential of 2.8 GW onshore wind, 5.6 GW of wave, and 4.5 GW of tidal stream (Baringa, 2013). Depending on the local context, this has already been exploited within the limits of local networks. Given the abundance of renewable energy on the islands - particularly Orkney - numerous energy projects have been developed. Orkney has been the case study of modelling electrical and thermal energy storage, finding that thermal storage has greater overall system benefits (Marczinkowski and Østergaard, 2019). Analysis for a Scottish island energy system using wind, electrolysis, and a hybrid hydrogen generators demonstrated it could meet local demands (Kennedy *et al.*, 2017).

Review of all energy sectors has been carried out for several Scottish islands. The Carbon Neutral Islands project aims to support six islands in carbon neutrality by 2040 - five years ahead of Scotland as a whole. In the first stages, carbon audits were produced for Barra, Great Cumbrae, Hoy, Islay, Raasay, and Yell. The next stages will develop action plans, to then be delivered in the hope that these exemplars will catalyse other islands (Scottish Government, 2023a). Audit of Orkney highlights the notable renewable energy potential, but also the need for infrastructure to keep pace with generation upgrades (Orkney Renewable Energy Forum, 2014). Though there are several reviews on biowaste utilisation (Section 5), no studies were identified integrating this with an energy systems context. Considering the whole systems context could result in a more efficient and lower impact net zero energy system.

2.6.2 Demand modelling of the islands

Energy audits for specific islands were the only identified demand modelling for Scottish islands. Orkney carried out an audit in 2003 (Northern and Western Isles Energy Efficiency Advice Centre, 2003) and 2014 (Orkney Renewable Energy Forum, 2014). The Carbon Neutral Islands project developed carbon audits for six islands, with the aim of setting an example for other islands to follow (Scottish Government, 2023a). Assessments of Scottish islands energy potential from biowaste (described in the following section) did not examine the potential for co-location with demand.

2.6.3 Biowaste potential of the islands

Numerous studies have highlighted the potential use of biowaste for energy and other applications in Scotland, some with a focus on the islands. The Scottish Government announced a bioenergy action plan due in 2023, but it has not been released at the time of writing (Scottish Government, 2021a). In other studies, nationally and for the islands, whisky, fish farming, and beer brewing have been a focus. Improved utilisation could be nationally significant, with these three sectors potentially contributing up to £800 million annually to the Scottish economy (Shaiith, 2015). The domestic use of bioresources for energy could more than double from 6.7 TWh to 14.0 TWh by 2030 (Ricardo Energy and Environment, 2019). By-products from these sectors are currently utilised to some extent, including for animal feed, fertilizer, anaerobic digestion, or CHP (Shaiith, 2015). There is potential for these other higher value products such as proteins, biofuels, or minerals, to be cascaded to maximise value added (Zero Waste Scotland, 2017; Scottish Enterprise, 2018, 2019). On the islands, the mainly wet feedstocks makes anaerobic digestion or biorefining are more suitable than combustion (Ricardo Energy and Environment, 2019). The islands of Islay and Jura, Orkney, and Shetland have been highlighted as bioenergy hubs due concentrations of fishing, brewing, and distilling (Shaiith, 2015). Due to the density of whisky distilleries, the bioenergy potential of Islay and Jura is recognised (Duguid and Strachan, 2016; Ricardo Energy and Environment, 2017; Edwards *et al.*, 2022).

Further work is needed to expand this understanding of bioenergy potential to other Scottish islands. To quantify other locally or nationally significant resource hotspots, further mapping would be required (Zero Waste Scotland, 2017). Improved synergies with other sectors could also be identified with more comprehensive modelling (Scottish Enterprise, 2019). This includes matching processes with existing heat demand (Shaiith, 2015), renewable energy integration (Zero Waste Scotland, 2017) and understanding of the flexibility in suitability of feedstocks (Green Alliance, 2015). It will also be important to develop an understanding of what scale would be most effective given the constraints of available resource, supply chains, transportation, shelf life and economic considerations. Any analysis of the energy potential from islands biowaste will need to consider potentially conflicting demands for other higher value products which could be more economically suitable for certain waste streams (Shaiith, 2015).

2.7 Summary of research gaps and thesis contribution

Review of existing literature has identified several gaps in key areas of whole energy systems modelling, demand modelling, biowaste, UK decarbonisation policy, and the Scottish islands. With this as a basis, this thesis will address the gaps summarised below to contribute to energy systems modelling literature in the following ways:

Demand model: Existing literature emphasises the importance of behaviour profiles in modelling demand, but faces challenges of data availability and specificity, especially for the non-domestic sector. To address this, this thesis introduces an innovative approach using time use data for hourly domestic and commercial demand. The bottom-up, 100% framework developed with freely available datasets could be adapted to any country or region with time use data and other building stock data available. The model, combined with outcomes of energy efficiency policies offers a unifying method for comparing the multiple benefits of energy efficiency, addressing challenges posed by differences in technologies and assessment metrics. Incorporating this 100% sample demand model with a wider energy systems model allows for demand side measures to be compared in a way which is not possible in other whole systems models (including the Governments) that generally consider demand as an exogenous input, which could be missing out on more optimal whole energy system solutions.

Biowaste model: Combing various datasets of waste production allows for the identification of synergies between types, rather than modelling single waste streams. Recognising collection costs as a potential barrier, a more detailed methodology using recursive DBSCAN clustering CVRP and OSMNX road networks increases the accuracy and specificity of collection costs estimation compared with weight-based metrics. The thesis contributes by combining this with a scenario-based framework, which considers facility configuration and generation technologies, allows for the heterogeneity of island contexts to be considered in depth, with solutions optimised for each region. Again, incorporating these results with a wider energy systems model could provide more optimal net zero configurations which Government modelling does not include.

Energy Systems Model: Existing energy models often lack consideration of circular economy principles, treat demand as exogenous input, and focus on specific sectors or annual demand. This research integrates in depth supply, demand and biowaste models into a comprehensive energy systems model, featuring high-temporal and spatial resolution, and covering a wide range of technologies and sectors. The combined modelling of electricity, hydrogen, and biogas markets is based on previous uses of PLEXOS. The main novelty lies with the integration of a 100% sample demand model and in-depth techno-economic modelling of biogas to develop an understanding of the regional implications of net zero policies. This demand-centred whole energy systems model places a different emphasis on results and highlights the distributional effects of net zero policies. High-resolution modelling of combined electricity and hydrogen balancing highlights how they could interact and raises questions about assumptions used to assess the technologies.

Scottish islands case study: This thesis develops a detailed case study of the energy systems of the Scottish islands, to an extent not identified in the literature. Model outputs include demand scenarios and biowaste potential, which will be available for local stakeholders to utilise. The work offers recommendations for effective policy design to maximise the potential success of achieving net zero targets, both locally and nationally. Throughout, areas of further research and gaps in data (nationally as well as for the islands) are identified for future work.

Net zero policy: Through greater resolution of modelling, interlinkages between models (particularly demand and bioresources), considering a wide range of technologies, and integration of policy outcomes into the modelling process, this thesis provides policy recommendations (Chapter 8) which lower spatial resolution modelling might not capture. It emphasises the importance of demand side measures and distributed technologies in minimising network stress, irrespective of other technology outcomes. Biogas from waste could similarly be a low-regret option that would help improve circularity and local energy system resilience. It also highlights the role that hydrogen and electrolysis could have for remote communities, but also raises further questions which would need to be addressed if the technology is to be widely used.

3 Methodology: the overall Net Zero model

The main output of this thesis is a net zero energy systems model for the Scottish islands, covering supply and demand to consider scenarios of energy balances in 2045 - Scotland's net zero target. The Net Zero model is set up in PLEXOS (Energy Exemplar, 2023a), an energy dispatch optimisation software, for which the methodology and structure is described in this chapter. To model a fully net zero energy system, the model combines Electricity and Gas (for hydrogen and biogas) Markets (specific objects in the PLEXOS modelling structure will be referred to with capitals). These optimise the dispatch of each energy type and are optimised via equations described in Section 3.2. The two Markets objects are linked via Power2X objects (used for hydrogen electrolysis). With demand electrification, electricity will have a more prominent role in overall energy systems modelling. The hourly dispatch of electricity markets alongside hydrogen electrolysis allows for synergies between the sectors to be considered, which could have implications for the developing hydrogen industry as an alternative to fossil fuels in sectors unlikely to be electrified.

As PLEXOS is designed mainly for market optimisation, other aspects identified as crucial to net zero identified in the literature have been modelled separately as inputs to the Net Zero model in PLEXOS. These are based on three main sub-models, outlined here and detailed in the following chapters: demand (Chapter 4); Biowaste (Chapter 5); supply, networks, and flexibility (Chapter 6). The Net Zero model has four main scenarios, which apply differing technology combinations to each sub-model, in addition to two periods of extreme weather for renewable energy systems (Butcher, Brown and Wallace, 2021). The model is set up in Python (Python Software Foundation, 2022) using the application programming interface (API) service to facilitate the range of scenarios (Energy Exemplar, 2023b). The Net Zero model in PLEXOS is summarised in Figure 3-1, with exogenous variables at the perimeter colour-coded by their provenance and variables optimised in PLEXOS given in the centre. The methodology and structure of this model will be described in this Chapter, followed by the detailed methodology of each sub-model, with Net Zero model results in Chapter 7.

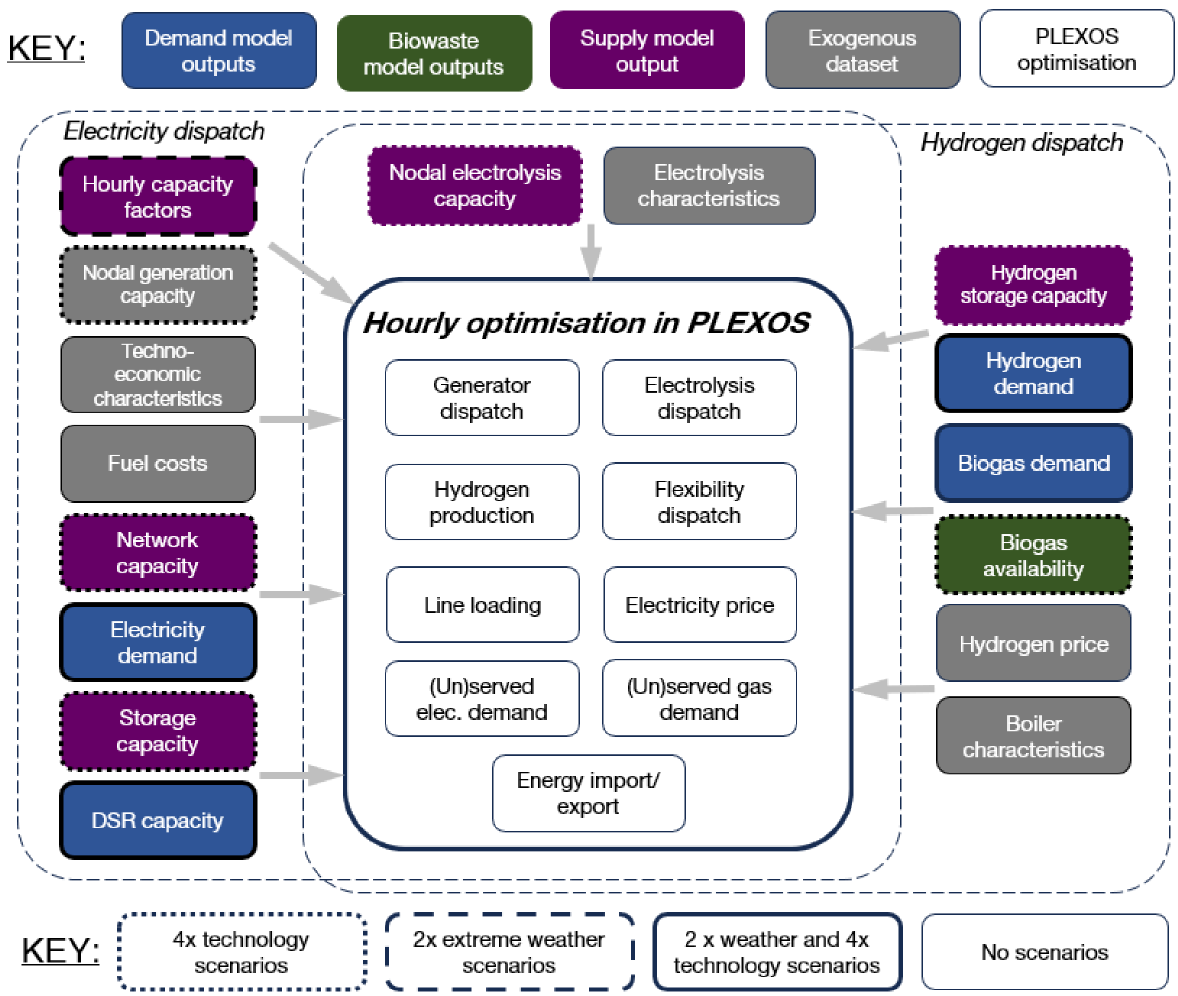

Figure 3-1: Structure of the Net Zero model in PLEXOS, with inputs from other models colour coded (all colours non-monochrome colours are models developed for this thesis) and scenarios indicated by the box outline.

The final model considers the four scenarios of different net zero technology configurations in the Scottish islands by 2045 based on the targets and achievement of local and national energy policies. The over-arching logic of these scenarios is outlined in this chapter, with specific policies which used to derive the scope for technology changes discussed in Chapters 4-6. Aspects of demand, supply, biogas, electrolysis, networks, and flexibility are varied to reflect the logic of each scenario. Whilst scenarios' technology balances differ, the Net Zero model shares common assumptions, described in Section 3.3. Most demand technically suitable to electrification will utilise existing infrastructure - other demand is assumed to be replaced by hydrogen-based fuels, either imported or produced locally via electrolysis. Renewable capacity (onshore wind and tidal steam) on the islands will grow in line with planned developments. To improve island resource utilisation, expansion of anaerobic digestion and biogas is modelled, alongside distributed flexibility measures. The scenario configurations trade-off between these technologies and their interactions from a whole systems perspective. As the case study of this work, the islands are modelled in detail, but a simplified version of the mainland UK is also modelled to account for interconnections.

The sub-models (Chapters 4-6) are set up so inputs can be varied in accordance with the overall scenarios and then used as inputs to the Net Zero model in PLEXOS (Figure 3-2). These chapters are loosely structured by describing the methodology, data used, validation against recorded data (where available), detailing of how the overall scenarios are transformed into model inputs, results of the scenario outputs, and discussion of the specific results from each chapter. In each case, results for each chapter are discussed at several resolutions dependent on the validation data used. These models are standalone in that they do not interlink until combined in the Net Zero model in PLEXOS. They are then combined into the Net Zero model described in this Chapter.

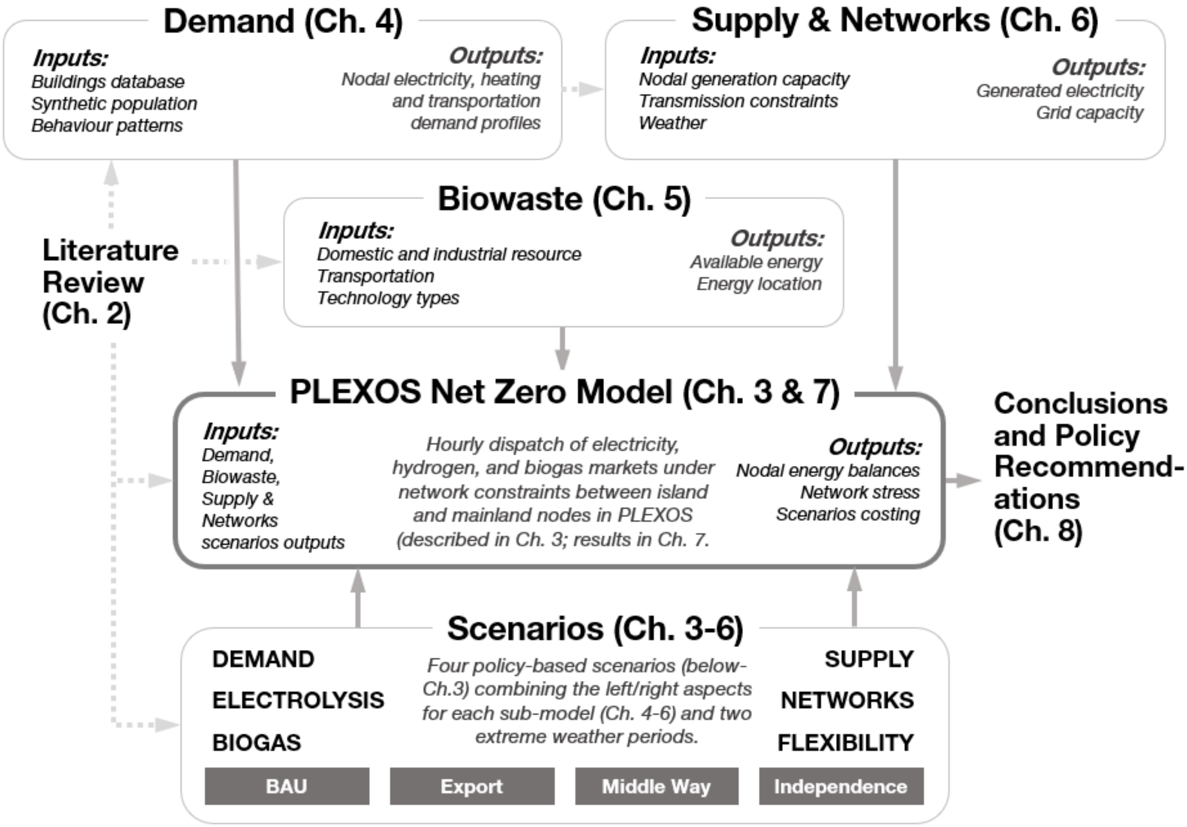

Figure 3-2: Main structure of the thesis, with chapter numbers for each model - the Net Zero model methodology is described here in Chapter 3, with results presented in Chapter 7, after discussion of each sub-model in Chapters 4-6.

To summarise each sub-model:

Demand mode (Chapter 4): structured around island-specific data, a bottom-up, 100% sample demand model is developed to cover all aspects of how energy is used and with what fuel for the islands. Domestic, commercial, industrial demand is modelled for electricity, hydrogen-based fuels, and heat. The main outputs of this are categorical, hourly demand profiles at the resolution of individual buildings, allowing understanding of how efficiency-based policies could affect individual properties.

Biowaste model (Chapter 5): to identify synergies between sectors, a biowaste database is developed from various datasets. A techno-economic model is developed to compare the main factors influencing the LCOE, based on scenarios of resource availability, facility configuration, and generation technologies. The potential energy and its cost are used as an input to PLEXOS.

Supply and networks model (Chapter 6): a simplified electricity-only version of the Net Zero model is set up for validation with recorded data. The scenarios of generation, electrolysis, and flexibility capacities and techno-economic characteristics for the Net Zero model are set up based on relevant constraining conditions.

This chapter focuses on the methodology of PLEXOS used for the Net Zero model: how the model is structured; the energy-dispatch optimisation process used; key assumptions and how they could affect the results; and how the final results in Chapter 7 will be assessed and costed. The novelty of this chapter consists of the following:

(i) *Combined modelling in PLEXOS:* the novel modelling framework in PLEXOS optimises the dynamics and interactions between energy markets. Unlike traditional modelling approaches that often focus on energy components in isolation, the hourly demand and dispatch of electricity, gas, and heat is modelled, to provide a holistic overview of the energy system. Electrolysis objects connect the optimisation of each market and allowing greater understanding of the interactions and synergies between them.

(ii) *Interconnected and high-resolution modelling approach:* the combination and resolution of the three sub-models (particularly the 100% sampling of the demand model) allows for more detailed analysis of the results from more varied perspectives than other modelling approaches focusing on individual energy system aspects. Few other models have adopted such a detailed resolution for a whole energy systems model.

(iii) *Integration of biowaste:* the novel incorporation of circular economy principles (via the biowaste model) with the whole systems modelling approach has been done in few other models and not at the resolution included here. Considering biowaste extends sustainable energy practices to include resources and circular economy principles.

3.1 Net Zero model structure

The Net Zero model combines the outputs of the three sub-models into an energy systems model in PLEXOS for the year of Scotland's net zero target - 2045. The model optimises the hourly dispatch of electricity, hydrogen, heating, battery energy storage system (BESS), and DSR to meet each fuel demand. This is achieved in PLEXOS through combining Electricity and Gas Markets structures (Figure 3-3). The system cost is minimised in both according to specific constraints (supply equalling demand, generator min/max limits; see Section 3.2). Other objects (Table 3-1) are attached to Nodes to locate them within the network and are separate for Electricity, Gas, and Heat Markets. The optimisation of Electricity and Gas/Heat markets occurs separately except through the linkage of electrolysis (Power2X in PLEXOS). Parameters described in Section 3.4.2 allow the Power2X to operate when there is curtailed renewable generation available, producing hydrogen to meet the nodal Gas Demand (hydrogen demand in Figure 3-3). The Gas and Heat nodes are linked by Heat Plant objects, representing dual-fuel boilers which can use biogas or hydrogen, depending on the availability of fuel, to meet industrial heat demand (the only non-electrified heat demand - see Section 4.3). The combination of Electricity and Gas Markets allows the Power2X objects to reduce curtailment by producing hydrogen and meet Gas Demand, thereby improving the efficiency of the two systems modelled separately.

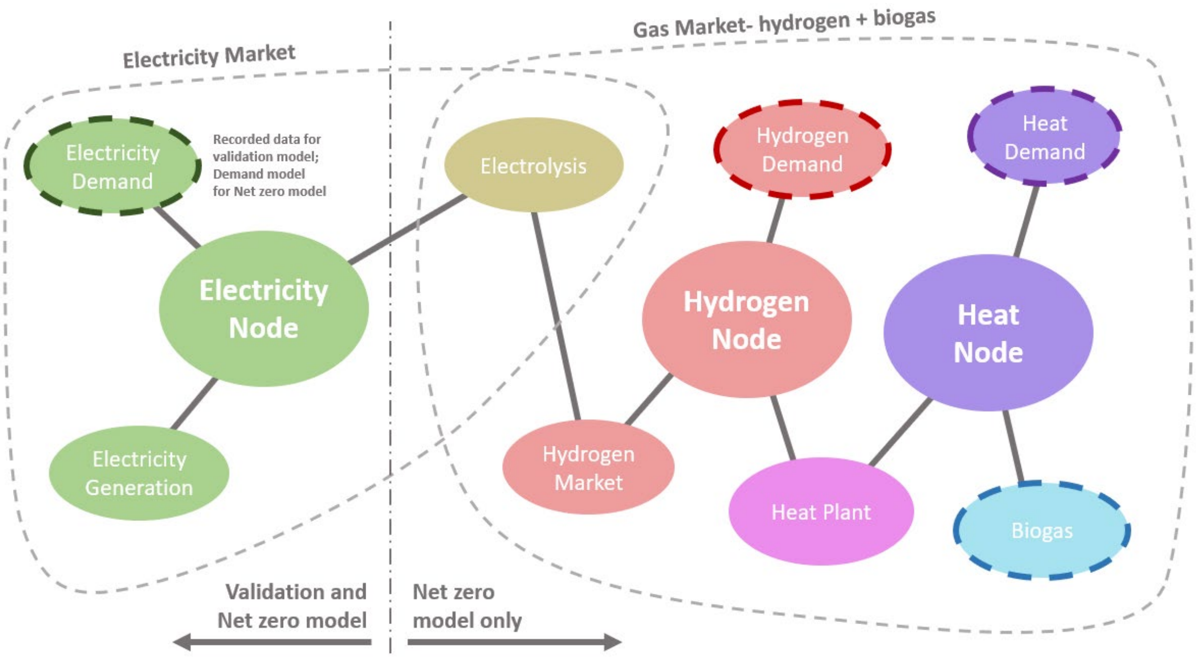

Figure 3-3: The structure of the validation and Net Zero models in PLEXOS. Demand, generation, and storage are connected to separate nodes for electricity, hydrogen, and heat. Dashed outlines are inputs from the respective models; the dispatch of all other aspects is optimised in PLEXOS. Recorded demand data is used for the validation model (Chapter 6); outputs of the demand model (Chapter 4) are used for the Net Zero model (Chapter 7).

Table 3-1: Objects used in PLEXOS and their relation to the node types - objects shared between nodes are bold.

Node type	*PLEXOS objects attached*
Electricity	Generators, Storage (i.e. BESS), Storages (pumped hydro), Lines, Demand, **Power2X (shared with Gas nodes)**, Electric Vehicles, and Charging Stations (the latter two used to represent DSR).
Gas	Gas Demand, **Power2X**, **Heat plant**, Gas Market.
Heat	**Heat Plant**, Heat Demand, Fuel (biogas supply)

Inputs indicated by dashed outlines in Figure 3-3, are validated separately for the Demand (Chapter 4) and Biogas (Chapter 5) models. A simplified Electricity Market-only model (left side of Figure 3-3) has been developed separately (Chapter 6) and validated using recorded generation and demand data.

3.2 Constraints and optimisation objectives in PLEXOS

PLEXOS is an energy dispatch optimisation model (Energy Exemplar, 2023a), which can both handle both long-term investment decisions and short-term energy dispatch by exchanging results between separate models. PLEXOS model structures include both Electricity and Gas Markets, which are both described here. Note that “gas” refers in PLEXOS to any gaseous fuel - while it has historically been used for natural gas, in this work will use hydrogen (Section 3.4.2) and biogas (Chapter 5). The Electricity Market model was developed for validation with recorded generation data (Section 6.2); the combined Electricity and Gas Markets model is used for the Net Zero model (results in Section 7).

PLEXOS works at a given timestep (in this case hourly), with model steps optimised over specific periods (monthly) in sequence. It has three modelling phases, but only the short term (ST) and medium term (MT) schedules have been used:

(i) *Short term (ST):* this optimises the hourly dispatch of generation and other technologies for the given period, where the cost of the whole system is minimised subject to the technical constraints described in the following sections.

(ii) *Medium term (MT):* storage (BESS and pumped hydro) requires optimisation over a longer period, including end-results for the following periods, so this model optimises their output over longer periods, with results being automatically passed to the ST model.

This section describes the optimisation equations used in PLEXOS - the actual techno-economic characteristics for each generation type are described in Section 6.1.

3.2.1 Electricity market dispatch

The ST schedule of PLEXOS optimises how generation dispatch meets demand. This considers key techno-economic parameters to minimise the cost function for the system (Eq. 3-1). The main cost aspects are included to optimise for fixed annual costs, variable costs - for thermal generation, this includes the fuel price and heat rates, whereas for renewables, this is purely based on the variable (VOM) costs.

$$Min \sum_{y} \left(FO\&MCost_g \times Pmax_g \right) + \sum_{t} \left(GenLoad_{g,t} \left(\left(FuelPrice_g \times HeatRate_g \right) + VO\&MCost_g \right) \right) \quad \text{Eq. 3-1}$$

$FO\&MCost_g$ = annual fixed operational costs for generator g (£/MW); Pmaxg = maximum capacity (MW); $GenLoad_{g,t}$ = energy generated for period $_t$ (MWh); $FuelPrice_g$ = price of fuel (£/MWh); $HeatRate_g$ = heat rate of generator (%); $VO\&MCost_g$ = variable operational costs (£/MWh).

This main optimisation problem is subject to several constraints. The most important of these is that generation must meet demand (the Net Zero model incudes electrolysis demand, but not the validation model - Section 6.2), or else increase the amount of unserved energy (Eq. 3-2). The cost of unserved energy being much higher than the cost of any generator forces all generation to come online (e.g. move further up the merit order in terms of generation cost) until there is no capacity left. Unserved energy could also be caused by insufficient interconnection capacity.

$$\sum_{t} \left(GenLoad + Unserved \right) = Demand_t + Demand_{P2X} \quad \text{Eq. 3-2}$$

GenLoad = total generation on the system for time t (MW); Unserved = unserved power (MW); $Demand_t$ = total electricity demand (MW); $Demand_{P2X}$= total electrolysis demand (MW).

Secondly, dispatch must obey generator limits (Eq. 3-3). For low-cost renewable generation, unless subject to grid constraints, this is dictated by the weather-derived capacity factor (Section 6.1.2). The same constraint is applied to transmission lines (Eq. 3-4) and storage technologies (pumped hydro and BESS; Eq. 3-5).

$$Pmin_g \leq GenLoad_g \leq Pmax_g \quad \text{Eq. 3-3}$$

$Pmin_g$ = minimum load factor for generator g (MW); $GenLoad_g$ = generator load (MW); $Pmax_g$ = Generator maximum capacity (MW).

$$Lineflow \leq Linemax \quad \text{Eq. 3-4}$$

Lineflow = flow on each line (MW); Linemax = maximum thermal capacity of the line (MW).

$$Storagemin_s \leq Capacity_s \leq Storagemax_s \quad \text{Eq. 3-5}$$

$Storagemin_s$ = minimum storage capacity for storage s (MWh); $Capacity_s$ = storage capacity (MWh); $Storagemax_s$ = Storage maximum capacity (MWh).

The final main constraint is planned (maintenance) and forced (unexpected technical disruptions) outages for generators. The total generation capacity includes this to account for capacity which could be out of action.

$$GenCap = Pmax_g - Outage \qquad \text{Eq. 3-6}$$

GenCap = capacity of generator (MW); Pmax$_g$ = maximum capacity of generator (MW); Outage = generator outages, forced and planned (MW).

These aspects are optimised for every (hourly) timestep of the model for the network of nodes connected by transmission lines. For aspects such as storage, dispatch needs to be optimised over a longer (multi-hourly) period, as the best price received (e.g. storing energy at the lowest price/minimum demand and dispatching at highest price/peak demand) - but also the best reduction of system costs - will depend on balancing the cost of purchasing energy with the price received for dispatch. This is optimised using the Horizon settings, which sets the period for which the ST model is optimised - in this case a month. This allows storage objects to optimise storing and dispatching energy over the longer period require to optimally generate revenue. It also allows start-up costs for thermal generation to be included, as for expensive to start generation (e.g. nuclear or biomass) may accept lower prices to avoid higher start up costs following shutting down.

3.2.2 Gas and heat market dispatch

To reiterate, Gas used here refers to both hydrogen and biogas. Hydrogen supply is calculated endogenously in PLEXOS (Section 3.2.3), with demand calculated separately (Section 4.3). Biogas supply is calculated from the available biowaste (Section 5.2), with supply considered to offset hydrogen demand. Essentially, hydrogen and biogas are defined as two separate fuels with exogenous prices used to optimise their dispatch in PLEXOS.

The basic methodology of the Gas and Heat Markets in PLEXOS is essentially the same as the Electricity Market in the previous section. There are Nodes of Demand and Gas Supply, but instead of modelling the Generator objects, Gas Demand is considered as being met directly by the availability of fuel (e.g. end-use technologies are not considered just the primary energy). However, Heat Demand is met through heat generator objects, which have costs and heat rates.

$$Min \sum_{t} (GasPrice_{m} \times GasDem_{n}) + (UnservedPrice_{n} \times GasUnserved_{n}) + \Big(\big(HeatDem_{n}\big((GasPrice_{m} + HeatRate_{n}) + VO\&MCost_{n}\big)\big)\Big) \quad \text{Eq. 3-7}$$

m=gas used to meet demand (-); n=gas node (-); t=period (h); $GasPrice_n$=price of gas (£/GJ); GasDem=gas demand (GJ); UnservedPrice=price of unserved gas demand (£/GJ); GasUnserved=unserved gas demand (GJ); HeatDem= heat demand (GJ); HeatRate= heat rate (%); $VO\&MCost_n$=£/GJ.

To simplify the model, Gas Storage objects were not included directly (see Section 3.4.2). Instead Fuel objects representing available gas are assigned to the mainland and island nodes. The island gas demand can then be met by either the local supply, which is hydrogen produced by local electrolysis objects, or imported from the mainland. The required storage capacity can then be calculated after the ST optimisation of PLEXOS by considering the greatest consecutive demand for (imported) gas from the mainland. This also allows for the hydrogen storage capacity required to export fuel (considered as the total excess electrolysis production in each timeframe), which is discussed in Section 7.3.1.

3.2.3 Connected electricity and gas markets through Power2X

The gas and electricity nodes are connected in PLEXOS through Power2X objects, representative of electrolysis used to produce hydrogen. Using Generation in the Electricity Market (the load is added to native load met by generation in Eq. 3-2), they produce hydrogen used to meet gas demand in the Gas Market, given in Eq. 3-7.

$$GasOut = P2XLoad \times Eff \quad \text{Eq. 3-8}$$

GasOut= hourly production of hydrogen (MWh); P2XLoad= operating capacity of electrolyser (MW); Eff= efficiency of electrolyser (%).

In PLEXOS, Power2X behaviour can be controlled by two variables related to the electricity price: the Shortage Price and Market Price, illustrated in Figure 3-4 and described as follows. These were set at the price of offshore wind (Section 6.1.1), meaning electrolysis would only operate with excess electricity from offshore wind, onshore wind and solar PV.

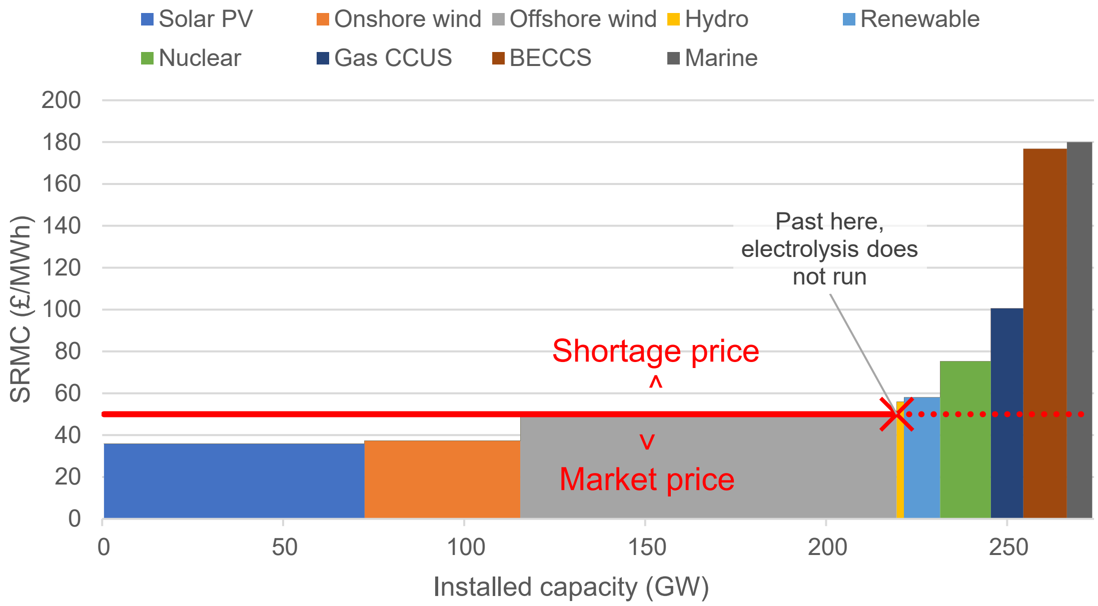

Figure 3-4: Modelled merit order of dispatch by short run marginal costs (SRMC) for the mainland and islands, with the red price threshold used to dictate the operation of electrolysis. Note that the graph only shows SRMC - to simulate longer term contracts in the model, nuclear, BECCS, and marine has been defined as "must run" to force it to operate as baseload.

Shortage Price (>£13.75 /GJ or >£49.50 /MWh): analogous to the value of lost load (VoLL) for Gas Demand in PLEXOS, this sets the penalty price for not meeting Gas Demand. This dictates up to what price of electricity the electrolysis will operate to meet demand. If this shortage price is higher than the VoLL, the electrolysis will cause electricity shortages to meet the gas demand; vice versa and gas demand will not be sufficiently met. Therefore, the Shortage Price is set equivalent to the most expensive generation that electrolysis will use to operate (e.g. offshore wind).

Market Price (<£13.75 /GJ or <£49.50 /MWh): one month is modelled per weather period (Section 3.4.5), so demand for hydrogen beyond this is forced using the Market Price. This purchases hydrogen from the Power2X objects at the Market Price to incentivise operation if the excess renewable generation exceeds the demand at that period. If this is greater than the Shortage Price, Gas Demand will not be met (it will all be sold at the Market Price), so setting it just below the Shortage Price means the electrolysis will operate using all the available curtailed wind generation when it exceeds the hydrogen demand.

3.3 Structuring of specific aspects in PLEXOS

Detailed structuring of the model in PLEXOS is described here where it does not relate to the Demand (Chapter 4), Biowaste (Chapter 5), or Supply (Chapter 6) models.

3.3.1 Future fuel prices

The validation model (Section 6) uses historic fuel prices for natural gas, biomass, nuclear, and coal. For costs projecting two decades or more ahead to net zero (BEIS, 2020b), there is considerable uncertainty about fuel prices. In the context of this model though, the main uncertainty around imported fuel prices relevant to islands will be hydrogen (discussed in Section 3.4.2). The LCOE for biogas is calculated in detail with associated sensitivity analysis (Section 5.7). Other thermal generation for the islands is not modelled (Section 6.4).

Although fuel prices are impossible to predict with any certainty, it is safer to assume fuel prices will not alter the merit order of thermal generation. Given technical constraints and other costs, nuclear and BECCS will always function most efficiently as baseload. For nuclear, irrespective of planned cost reductions through new models, the overall cost will always be dictated by the capital costs of civil works and not the fuel price (World Nuclear Report, 2021). For BECCS, given planned use in providing negative emissions, will also likely operate as much as possible (National Grid, 2023). With higher CCUS costs, abated gas will be less economic to run for longer periods, however this will depend on how CCUS costs are structured. Where hydrogen fits into this order will be highly dependent on the price of hydrogen, how much green or blue hydrogen production capacity there is.

For these generators, the only effect needed for the islands is the mainland merit order of dispatch. Although other fuel prices could vary by 2045, the merit order of dispatch is unlikely to alter due to the lack of “fuel-on-fuel” competition in the UK (Maximov *et al.*, 2023). As the most important mainland aspect in the model is electricity transmission and its price, if the relationship between thermal generation does not affect the merit order of dispatch relative to renewables, it is unimportant to results. Thermal generation is highly unlikely to be cheaper than renewables, so optimised electricity dispatch will prioritise the islands. Fuel prices will of course affect the price of electricity exported from the mainland, but if this is not less than island generation then it should not affect island dispatch. The main concern for generation, BESS, and electrolysis on the islands will be whether local generation exceeds demand, and if not, whether wind is price-setting on the mainland - in addition to grid constraints. Any cases where it is not will likely result in BESS or electrolysis being uneconomic to run. The main thing the mainland generation model needs to capture occurs when wind generation is sufficient to meet demand plus BESS and electrolysis, which should be less affected by future variation in fuel prices.

3.3.2 How hydrogen and electrolysis are considered

Hydrogen as a fuel must be considered differently. The uncertainty around its potential role in net zero is considerable- especially for small, remote communities like the Scottish islands. This uncertainty reduces the robustness and availability of data, meaning that it has not been modelled with as much specificity as other aspects such as demand electrification or renewable generation. With this in mind, it is anticipated that hydrogen could have a significant role in reducing curtailment of wind generation by effectively storing electrical energy (National Grid, 2023). As described, Power2X (e.g. electrolysis) objects in PLEXOS link Electricity and Gas Markets (Figure 3-3) to produce hydrogen from electricity which can be used to meet exogenous hydrogen demand (Section 4.3). Although there is significant uncertainty, review of options has found using curtailed energy and proton membrane exchange as potentially the cheapest method (excluding other yet-undemonstrated options such as CCUS enabled biomass gasification) (BEIS, 2021a). This has been modelled for electrolysis in the Net Zero model (Section 6.1.1 and 6.4.3).

Whereas the production of small-scale, locally produced can be considered here in more detail, modelling the cost of imported hydrogen is outside the scope of this work. There is significantly more uncertainty in the price of hydrogen if established as a commodity, dependent on the extent of its role nationally or globally; the optimal fuel conversion technologies; what colour it is (green, grey, blue, etc); how it is stored and transported; and so on. With respect to modelling the islands, the key aspect is comparing the costs of import that would make locally produced hydrogen uneconomical. Rather than considering hydrogen price as an endogenous variable in PLEXOS, it is considered as a sensitivity to understand what effect the price could have on local production (Section 7.3). The average price assumed in the FES of 23.5 p/kWh (£65 /GJ) has been used, with the range of values 12-35 p/kWh (£33-97 /GJ) (National Grid, 2023) considered (modelled fuel prices are summarised in Section 3.6.4).

Fuel price elasticity leading to fuel-switching due to prices has not been modelled, as it is assumed that due to technical constraints (described in Section 4.3), specific demand types are met by either electricity or hydrogen-based fuels. If considered, it could affect the uptake of biogas, particularly for industry (see Section 5.6 and 8.2.3). Lower hydrogen prices would make biogas less cost-effective, but conversely if hydrogen prices are higher, more biogas could be economically utilised than calculated given the upper affordability limit imposed (Section 5.1.2).

To consider electrolysis on the islands, scenarios (Section 3.5) have been set up to reflect the trade-off between imports and local production of hydrogen. Transporting and storing hydrogen will be more expensive than fossil fuels and conversion to other, easier-to-transport energy vectors will be costly (BEIS, 2021a). These will be particularly high for the islands given their remoteness and unsuitability for cheaper transportation (pipelines) or storage (geological features). If transport and storage costs are too high, local production could be more economical. During periods of high island generation, rather than upgrading already constrained capacity of local grids to export electricity, producing hydrogen in situ could negate transport and reduce storage costs, as well as minimising curtailment and stabilising local grids. This trade-off will also depend on cost-reductions through economies of scale for larger production facilities; what the market price of hydrogen is (if a market develops); how it is produced; and how much excess local generation is available for electrolysis. This will be compared between the scenarios, with implications discussed in Section 8.2.3.

Whether small-scale electrolysis could be a suitable technology to help minimise curtailed renewable generation for the islands and remote communities would depend on several major aspects which would need to be in place:

(i) *Competitiveness with other sources of hydrogen:* if economies of scale are too great, transport/storage costs (Section 3.6.2) can be reduced, or blue hydrogen can be produced more cheaply, then local electrolysis would not make sense. If costs to import or export the fuel are too high (Section 3.6.4), then local production sized to meet demand might be more attractive.

(ii) *Availability of excess renewable energy:* the availability of island energy will depend not just on local capacity, but also on the mainland grid constraints - particularly the north of Scotland, where transmission constraints will continue to limit generation being imported to demand further south.

(iii) *Balancing of the network:* if electrolysers are not directly connected with generation, then the network would require balancing to match generation, existing demand, curtailment, and electrolysis demand.

(iv) *Matching of supply and demand:* per (iii), guaranteed buyers of the fuel would be needed to support the business case for local electrolysis.

(v) *Understanding payment for electricity:* Government modelling has assumed otherwise curtailed electricity would be available at no cost (BEIS, 2021a), but it seems implausible that generators would accept this given current curtailment

payments (de Berker, 2024). More clarity on the payment structure is needed to understand what effect it could have on the price of hydrogen.

(vi) *Favourable policy environment:* in the early stages, electrolysis will be highly dependent on government funding and support. Potential policies will be discussed in Section 8.2.3.

(vii) *A clear business case for investors:* the islands would need to be an attractive business case to encourage investment, which would be a combination of the above aspects.

3.3.3 Hydrogen storage sizing calculations

On the mainland, hydrogen demand is not modelled, therefore the only aspect forcing the electrolysis to run is the Market Price (Section 3.2.3). On the islands, demand for hydrogen is defined in PLEXOS using the "Gas Demand" object as well as the Market Price. The Market object which the Market Price is defined for means that hydrogen storage need not be considered in the ST optimisation of PLEXOS - hydrogen storage to meet demand can be calculated as the consecutive period of shortages (i.e. periods where local demand is not met by electrolysis) with the greatest total. This is illustrated with a sample period of cumulative hydrogen sales minus shortage demand in Figure 3-5. The larger of the maxima and minima (positive in Figure 3-5 refers to hydrogen production in excess of local demand and negative denoting shortage, requiring imports) is used for cost calculations (described in Section 3.5) but not optimisation to simplify operation of the model.

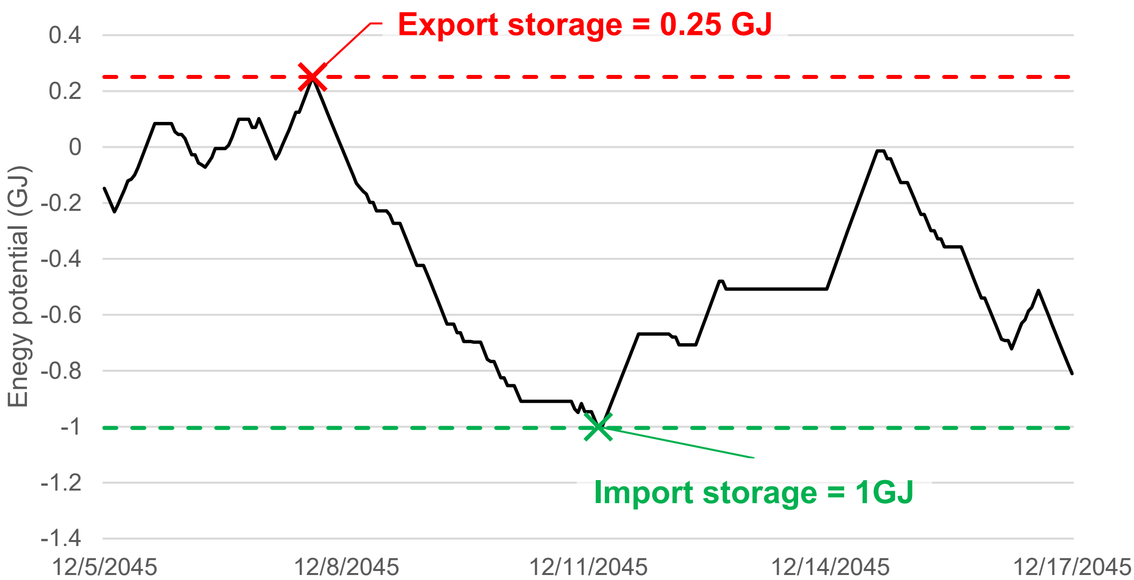

Figure 3-5: Example calculation of the required hydrogen storage size, where the line represents the cumulative net of sales to the market object less gas shortages (e.g. gas demand when not met by local electrolysis).

Fuel imports to the Flotta terminal in Orkney occur once every two weeks (Orkney Islands Council, 2022a). Due to corresponding most closely with the economic-optimum weekly frequency of load-discharge cycles has been used to select liquefied storage as the most suitable hydrogen storage technology (DNV GL, 2019). Mapping of geological hydrogen storage potential for the UK does not indicate any on the islands, so it has not been considered (Katriona Edlmann, 2023).

3.3.4 Energy markets, use of system charges and subsidies

The validation model set up for 2017/18 (Section 6.2) included use of system (BSuoS and TNuoS) charges and subsidies (CfDs, ROCs, and FiTs) (see Section 6.2). With the “biggest electricity market reform in a generation” underway (BEIS, 2022i), its not clear what electricity markets could look like in five years time, let alone by 2045. This does not even include how hydrogen and demand flexibility (e.g. V2G) could operate. Therefore, the implications of existing and planned market designs affecting the final Net Zero model should be considered.

Firstly to consider effects on the validation model, the use of system charges was used to reflect the costs borne by generators and the final price of electricity. While BSuoS vary by location, it was only ±3% for the validation year of 2017/18 (National Grid, 2019c). Whilst there are varied charges by connection types, they do not distinguish between types of generation. Whatever the structure of balancing market cost recovery is, it will likely be proportional to the volume (MWh) of balancing and type of generation (which for the islands is only wind and some tidal current). TNuoS would also likely be similar or identical for the islands given their similar locations at the extremities of the UK network and constrained network capacity. Proposed LMP could have the greatest effect on the energy systems for the islands. Therefore, the main effect this would have is increasing the modelled price of electricity, but this unlikely to affect the merit order of dispatch, but could prioritise mainland generation over island capacity, increasing island curtailment. These aspects effect on the Net Zero model results is discussed in Section 7.5.4.

The future role of subsidies is less clear. More generally, energy markets have a peculiar position with respect to regulation and subsidy relative to other commodities - particularly for electricity due to its instantaneous balancing. Market design should foster efficiencies that arise from trading on a fair and non-monopolistic market, but energy cannot be treated purely as a commodity due to being an essential service (Léautier, 2019). Arguably all generation, renewable or otherwise, is to some extent subsidised. For low-carbon generation in the UK, this is CfDs; for thermal generation, it is capacity markets or neglecting external costs of CO_2 emissions (Evans, 2018). The form this will take in the future is uncertain, in the near term due to ongoing market reform, but in the longer term even more so with the transition to an Energy System Operator (BEIS, 2022i). Although some have argued for a post-subsidy future for renewables, the Government's position has been to support subsidies that can bring down cost to consumers (Hirst, 2018), which the CfD for example has by reducing project risk and reducing borrowing costs (Evans, 2018). Whatever the state of energy market subsidies by 2045 though, it seems unlikely that the lack of "fuel-on-fuel" competition in the UK will change (Maximov *et al.*, 2023). In other words, the merit order of dispatch would likely be the same, with renewables running when they are able to, with other more expensive generation, (BESS, gas CCUS, hydrogen or flexibility) making up the remainder.

For the islands, only modelled with onshore wind and limited tidal current, subsidies are unlikely to affect the structure of the energy system from an electricity generation side. Assuming that there is no change to the merit order (no "fuel-on-fuel" competition), the effect for the mainland would only be on the price of electricity, which again is less important relative to balancing the energy demand of the islands. Overall cost which is considered separately from the model optimisation (Section 7.4). Subsidies with a greater effect on results would be support for small-scale electrolysis or anaerobic digestion, but these are again considered through the separate scenarios rather than as factors affecting the optimisation of PLEXOS.

3.3.5 Modelled nodes

The 100% sample nature of the demand model allows configuration in any arrangement of geographic area as required by model objectives, but this is limited by computational constraints of optimising energy dispatch in PLEXOS. With four technology scenarios (Section 3.5) and two extreme weather scenarios (Section 3.4.5), the model would need to be run eight times, limiting how detailed the outputs of each sub-model could be. The main geographic feature the Net Zero model would need to capture is transmission constraints.

The three main island groups have ANM systems (Figure 1-2) splitting them into sectors where renewable capacity is constrained by network thermal limits (Howison and Stamatiadis, 2017). When generation could exceed these limits, it is curtailed by the ANM system. To capture these network constraints whilst minimising run time by modelling fewer nodes, the ANM areas were used in the final model (Figure 3-6). That the ANM areas are already identified as major network limitations indicates that a more detailed nodal model would unlikely provide any greater insight, therefore unneccessarily taking longer to run. The node naming prefix indicates the local authority, with nodes numbered 1-30.

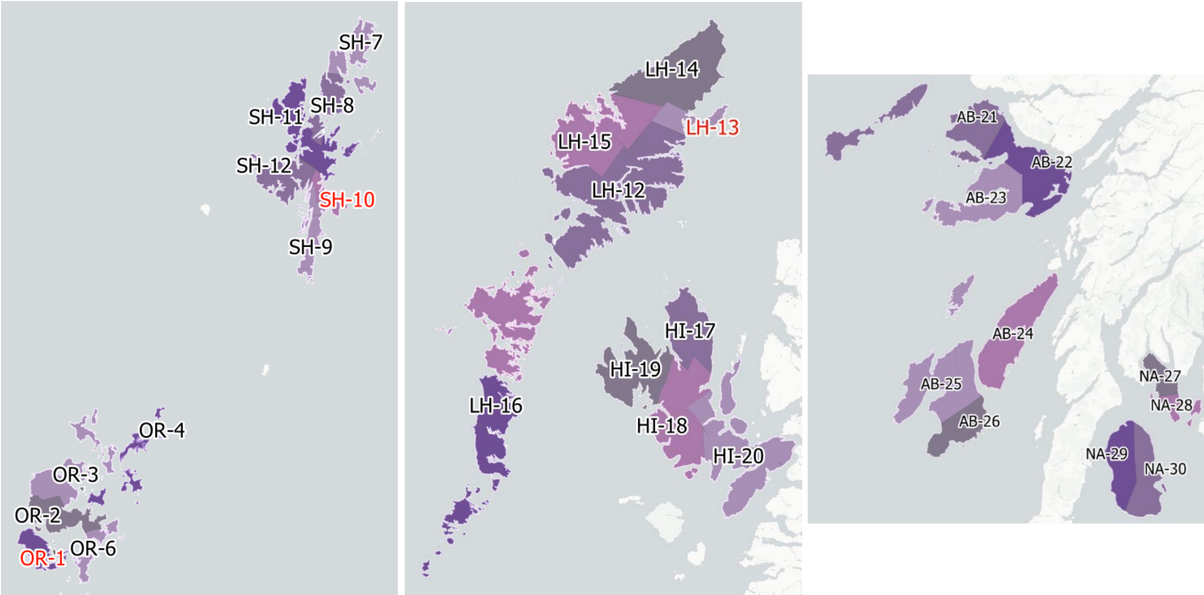

Figure 3-6: Nodes of supply and demand in the Net Zero model - labels in red indicate where transmission network connected capacity is assumed to join the distribution network.

Supply (Section 6.4) and demand (Section 4.6) for each node type in PLEXOS (Electricity, Gas/hydrogen, and Heat - see Figure 3-3), were assigned to unique Node objects in PLEXOS for each.

The focus of the Net Zero model being decarbonisation of the Scottish islands, it was set up in greater detail than for the whole UK (Section 4.4 and 6.3). The mainland UK is treated as a single node, but calculation of renewable capacity factors uses separate nodes to capture geographic diversity (Section 6.1.2). In the validation model (Section 6.2) though, nodes were modelled in PLEXOS for each 14-distribution network operator (DNO) region to match the availability of the demand data used and reduced computational complexity.

Interconnections with Europe have not been modelled for simplicity. The main effect with respect to modelling net zero specifically for the islands would be to alter the price of electricity depending on the balance of UK and European generation. With the main point of modelling the mainland for the islands being the balance of imports/exports, while this could affect the timing of when wind is the price-setting generation, the scale of interconnections planned in the FES (19.5 GW) versus the total wind and solar PV capacity (197.3 GW) (National Grid, 2023) would make this less significant than the potential generation.

3.3.6 Extreme weather scenarios used

Understanding the effects of weather on managing the whole system at an hourly level is essential with increasing dependency on intermittent renewables. The sub-models have been developed based on weather from specific time periods. For the supply side, this involves using the Renewables Ninja API (Pfenninger and Staffell, 2019) to collect capacity factors for specific locations for wind and solar generation, which have been averaged for the model nodes (Section 6.1.2). For the demand model, this consists of weather data extracted from the OikoLab API (Oikolab, 2021), which was used as an input to SimStock for calculating heating and lighting demand (Section 4.2), as well as to account for the seasonality of various demand types such as refrigeration and cooking (Section 4.1.6). Both the Renewables Ninja and OikoLab services are based on the ERA5 reanalysis database (Copernicus Climate Change Service (C3S), 2017), with the former being designed to output capacity factors and the latter being designed for building simulation weather files.

Weather periods in the Net Zero model should capture periods of maximum stress. The system operating in these periods indicates resilience in remaining conditions. A Met Office review of adverse weather scenarios for the UK and EU was used, assessing 40 years of weather data for the UK and Europe, categorising periods of long-duration weather according to severity - from 1 in 2 years, up to a maximum of 1 in >100 years (Butcher, Brown and Wallace, 2021). Although the study identified three main categories of adverse weather conditions, it was decided to focus on just two for the islands - peak winter demand/ wind drought; and minimum summer demand/ wind surplus. The final scenario of summer peak demand/ wind drought was considered less severe than the winter equivalent due minimal island cooling demand. The exact period modelled are described below (Table 3-3) - specific variables are described in Section 4.2.6. With the main relevance to modelling net zero for the islands being capturing the balances of interconnector flows, although the worst case scenario from an energy system perspective might not be the same for the islands as the mainland, maximum stress on the island should occur when there is no electricity available from the mainland given the over-sizing of interconnectors relative to local demand. The problem of oversupply from the mainland is more clearly applicable. More detailed analysis of weather data would be needed to demonstrate this fully though.

Table 3-2: Scenarios of extreme weather used in the model.

Season	Winter	Summer
Description	Wind drought, peak demand	Surplus generation
Severity	Maximum; 1 in >100years	
Start date	1/12/2006	1/4/2015
End date	29/12/2006	29/4/2015

3.4 Scenarios of island decarbonisation

This section will outline the narrative and logic of the Net Zero model scenarios. The scenarios are deterministic projections which are mapped out within the solution space of the FES for the year 2045 only. Investment pathways are not modelled but are discussed in Section 8.4. How inputs for each model are varied to match the logic of these scenarios for each model (along with outputs) is described in Sections 4.6, 5.8, and 6.5 for the Demand, Biogas, and Supply models respectively.

Essentially, the main question for the islands is: given their significant renewable resources, how can the energy best be utilised? This depends though on who defines the perspective of “best” - some options could be more beneficial for the islanders, others more so for the mainland or network operator. Outcomes for different stakeholders will be considered in the analysis of results. The balance of investment and policy support between scenarios is varied to consider the trade-offs of each. There is an added element of energy security and self-sufficiency. Currently, the islands are mainly net energy importers and reliant on fossil fuels (excepting Orkney which net exports electricity) (Orkney Renewable Energy Forum, 2014). Their exceptional renewable energy potential, low population, and hence local demand mean that they could all feasibly be net exporters of energy, excluding areas of heritage or natural beauty. However, the tiny island of Eigg has already achieved energy independence through a 100% renewable system (Chmiel and Bhattacharyya, 2015). Excess local renewable energy (particularly combined with under-consideration LMP) (Grubb *et al.*, 2022) could encourage innovative local industries and uses - as it already has with the range of hydrogen projects on Orkney (Fuel Cells and Hydrogen Joint Undertaking, 2018). Scenarios will consider the context of what could be achievable given policy support between now and 2045.

Many islands have already developed renewable capacity to the limits of local networks, resulting in significant curtailment. There are then several options which could allow for better utilisation of the available energy. Networks and interconnections to the mainland can be upgraded, as is planned for the three main island groups. Electrolysis co-located with supply on the islands could alleviate grid constraints and produce storable hydrogen. The potential for either option is also dependent on local demand and flexibility investment. Development of the biogas-from-waste potential could also help to improve resource utilisation and reduce dependence on imports.

The FES produced by National Grid have been used to define the decision space within which the modelled scenarios are set up (which in turn is influenced by the CCC) (National Grid, 2023). As per the FES, these scenarios do not optimise the long-term investment in energy infrastructure. Instead, they represent differing pathways of technology development from now until 2045, which reflect prioritising different aspects of the net zero transition. These are not intended to capture all of the uncertainty regarding decarbonisation. The FES is effectively used to map out the solution space of technology balances within which the scenarios for the islands are defined based on their local contexts. The localised focus of this thesis (with scales of hundreds of megawatts) means that the scenarios modelled are not directly comparable to the national-scale FES (tens of gigawatts) due to the differing scales of technologies, but the respective FES scenarios are indicated below where relevant.

These scenarios do not optimise the configuration of a net zero energy system under the large uncertainty that still exists for many aspects of decarbonisation. They have been set up to reflect alternative development pathways that the UK (obviously influenced by international technology developments) could pursue to decarbonise. They do not capture the whole range of uncertainty inherent to the creation of entirely new energy sectors (such as hydrogen). Whilst the hourly dispatch of generators, storage, and electrolysis in PLEXOS and aspects of each sub-model (e.g. waste collection costs in Section 5.3) are optimised, the configurations of technology capacities by scenario are not. Instead, they are defined within the boundaries of the FES, as outlined below in Table 3-4 and described in detail in Sections 4.6 for Demand, 5.8 for Biogas, and 6.5 for Supply and Networks models. They are intended to illustrate how different factors interact in an energy system at a resolution higher than annual and national modelling. These reflect potential outcomes for levels of policy support which are used to define the potential scope for each technology and modelled aspect (described in detail in the sections listed above). They are not directly comparable, as outcomes in terms of energy balances, investment, and Government support are all very different, but instead will be used in conjunction with the high-resolution modelling approach to provide a more in-depth perspective of how these extremes of technology deployment could result in differing outcomes for remote communities like the Scottish islands.

3.4.1 Scenario logic and outline

With this in mind, the four Net Zero model scenarios set up for the islands in 2045 can be summarised. They are based around the scenarios of the FES and the local energy contexts of the islands, which is referred to below where it has influenced the structuring of the scenarios.

3.4.1.1 Business-as-usual (BAU), or electricity supply-led

Based on the "Falling Short" scenario of the FES. this represents where net zero would end up under the current direction of national energy policy. The islands have been recognised as having a significant renewable energy resource, which in some places has already been developed to the limits of island interconnections (e.g. Orkney). Plans for further renewable capacity have in the last 20 years has been facilitated by interconnection expansion for Orkney, Shetland and Na h-Eileanan Siar (Ofgem, 2020) and there has been no evidence so far in Government policy of support for alternative solutions (e.g. electrolysis or flexibility) to support greater renewable capacity in remote communities. This scenario therefore considers the maximum deployment of transmission-scale renewables on the islands facilitated through upgraded island interconnections as per the last 20 years development on the islands. This makes the only export from the islands the excess electricity, which is transmitted back to the mainland, but makes the islands dependent on import of hydrogen-based fuels which are produced elsewhere (either the mainland UK or internationally). Given the lack of support for remote communities in policy currently, no investment in local flexibility or BESS is made and there is more limited investment in energy efficiency per historic trends for energy efficiency in the region.

3.4.1.2 Export, or hydrogen supply-led

Alternatively to facilitating expanded renewable capacity through interconnections, this scenario uses electrolysis capacity on the islands to utilise excess renewable generation, with the energy being instead transported in the form of hydrogen. It is based on the FES “System Transformation” scenario. An island in Orkney has already demonstrated the potential for this in the BIG HIT project which produces hydrogen for a local authority vehicles from a local wind turbine (Fuel Cells and Hydrogen Joint Undertaking, 2018). This scenario however assumes that there would be a significant degree of policy support for localised electrolysis capacity as a way of minimising renewable curtailment, but also to simulate local industry (through cheaper energy or in producing hydrogen). Policy and energy market reform would be needed to facilitate the co-location of hydrogen production, demand, and export capacity for the entirely new energy sector. Given the excess of local generation relative to local demand, this allows the islands to produce excess hydrogen which could be exported to the mainland. Similarly to he BAU scenario, there is no additional investment is made in flexibility or BESS, so stress on networks will be higher. The same BAU trajectory of energy efficiency changes is also assumed.

3.4.1.3 Independence, or demand-led

Based on the “Leading the Way scenario of the FES. This scenario takes a more holistic approach for the local decarbonisation of the islands through focusing on distributed generation, energy efficiency, localised flexibility, and smaller-scale electrolysis (relative to the Export scenario). This allows a reduced investment in larger-scale transmission level infrastructure, but despite this, the greater reduction in demand and increased local flexibility should allow for greater exports of electricity and hydrogen. The maximum utilisation of local biogas also frees up more energy capacity that could be exported, as well as improving the local independence and resilience of the islands. This scenario would be enabled by community-scale investment to encourage lower and more responsive demand that would enable better utilisation of renewable capacity on existing network infrastructure. This scenario represents the biggest departure from existing policy, which a much greater investment in energy efficiency required and more support for distributed, community-scale energy resources needed to set up these localised solutions.

3.4.1.4 Middle Way, or balanced approach

To understand if there were any non-linearities in the results of the other scenarios, this scenario considers a mid-point of the other three. It is essentially a less extreme version of the Independence scenario, with generation and electrolysis capacities halfway to the Export scenario. This will highlight if the upsides of any scenario might have diminishing returns that could be cost-effective. It is not based on a specific scenario of the FES, but rather as a mid-point of the others.

3.4.2 Sectoral description

The four scenarios are classified in terms of six main net zero aspects: supply, demand, electrolysis, biogas, flexibility, and networks. Each aspect has scenarios specific to the Net Zero model scenario dictating how it is translated into PLEXOS inputs. Specific descriptions of each aspect are summarised graphically in Figure 3-7 and in Table 3-4 and then detailed in their respective chapters.

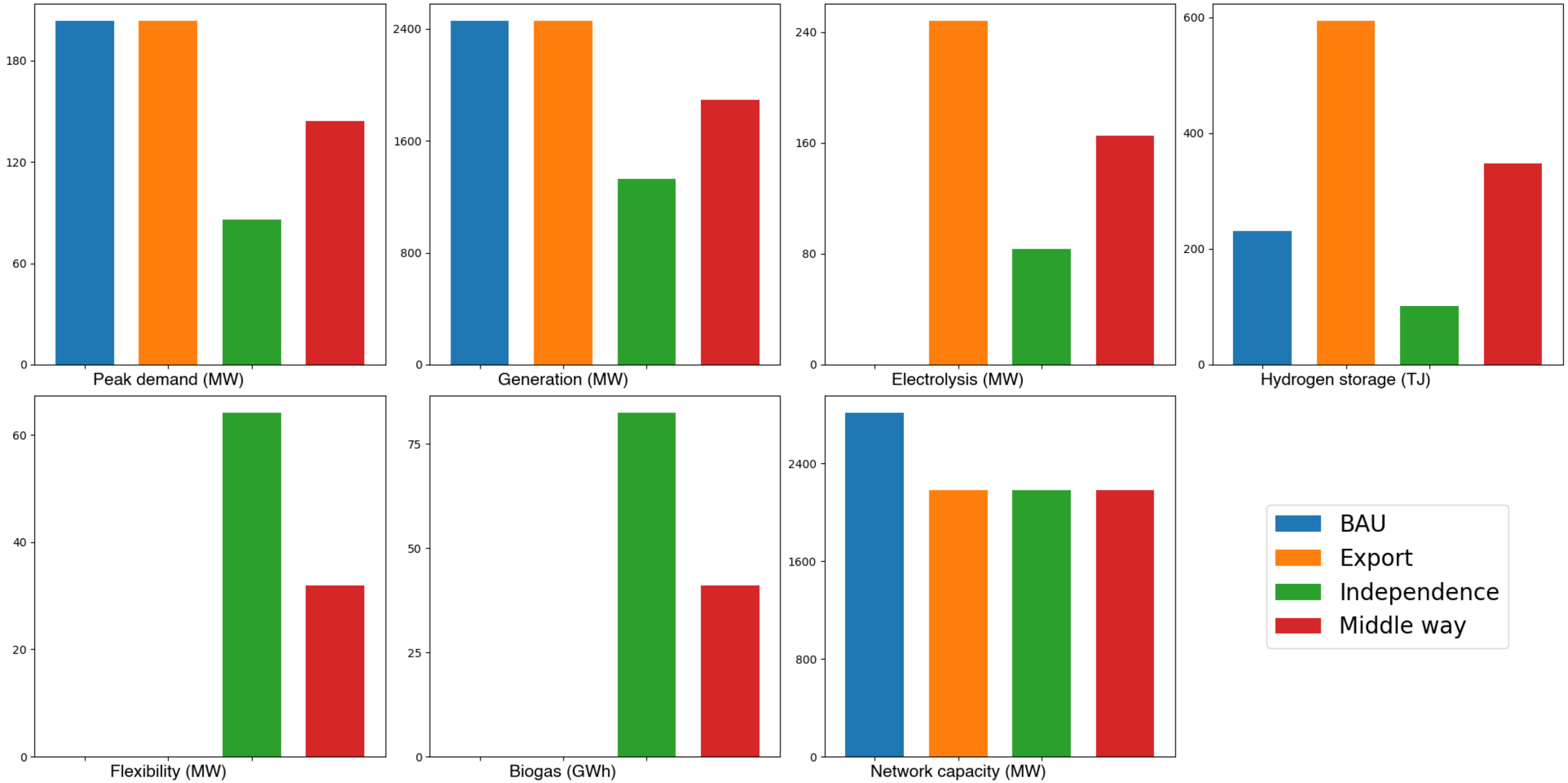

Figure 3-7: Graphical summary of the differences in technology capacities for each scenario. Capacities for each scenario are defined within the technically feasible capacity for each region- this is summarised in Table 3-4 and described in detail in Sections 4.6, 5.8, and 6.5.

Table 3-3: Supply and demand scenarios, with technologies and policy achievement described. All aspects (except electrolysis and networks) have the two extremes described here, with a third as the average of the two, excluding for electrolysis and networks, which only have the distinct scenarios shown here.

	Definition	*Scenarios*	*Description*
Supply	Planned and potential renewable generation capacity on the islands.	BAU, Export	Reliance on energy imported from the mainland, e.g. offshore wind, nuclear, CCUS. Greater stress on transmission and distribution infrastructure.
		Independence	Greater investment in local, small-scale solar PV and onshore wind. More complex balancing of system but less stress on transmission.
Demand	Projected electricity, hydrogen, and heat demand on the islands based on policy achievement.	BAU, Export	Current trajectory of demand-side policies, increased electrification, efficiency targets not met and minimal DSR. No improvements to transport efficiency.
		Independence	Greater efficiency ambition that meets targets through technology deployment. DSR reduces network stress and increase energy export. More efficient modes of transport are encouraged.
Biogas	Amount of available biogas from all resources; used for distillery heat.	Independence	The maximum economically usable biowaste on the islands, applied to displace industrial heat in the demand model which will minimise local hydrogen demand and need for imports.
		BAU, Export	No islands biowaste are utilised to produce biogas - meeting heat demand will be entirely met through local or imported hydrogen depending on the scenario.
Electrolysis	Local electrolyser capacity on the islands; hydrogen used locally or exported.	Independence	Electrolysis capacity for each node is dictated by local demand, assuming a capacity factor of 60%. This is also constrained by the available Local development plan (LDP) area.
		Export	Where average local curtailment of renewable generation due to grid constraints is greater than the electrolysis capacity from demand, this has been used to dictate capacity.
		BAU	There is no islands electrolysis capacity - hydrogen-based fuels are imported fuels.
Flexibility	Nodal capacity for BESS and DSR on the islands.	Independence	Nodal BESS is assumed at the proportion of demand to BESS from FES, subject to LDP constraints. DSR is assumed at a 50% uptake rate for certain categories of demand. This will help to balance local networks and deal with grid constraints.
		BAU, Export	No distributed flexibility is considered for the islands. Meeting demand will be entirely dependent on the capacity of local networks to transmit electricity at the required time.
Networks	Transmission network upgrades between nodes.	BAU	Electricity networks are upgraded by the minimum required to displace the average curtailment of initial model runs. This does not eliminate curtailment but will reduce it.
		Export, Independence	Existing infrastructure is used as an input to the model with no alteration. In cases with increased demand, there could be unserved energy.

3.5 Major assumptions for all models

This section describes the major assumptions made in the model (listed in Table 3-2). Two main assumptions relating to net zero require further discussion. Firstly, that net zero is achievable on time. The scenarios assume that the islands energy system will be completely decarbonised by 2045, but whether this will happen in the next two decades is uncertain. Given the recent rollback of targets (UK Government, 2024) (Section 2.5), it will likely be dependent on the success of challenges to UK Government policy which is legally bound to meeting net zero targets (provided this isn't also reversed). Whether or not successful on time, the scenarios are set up to compare alternative outcomes for the islands, rather than specifically how they get there. However, the steps and investment pathways required to realise each scenario are discussed in Section 8.4. The modelled outcome would effectively be the same whenever zero is achieved. All sub-scenarios informing the main scenarios (see Section 3.5) are informed by existing policies or planned constructions such that they should all be within the realms of possibility.

Secondly, as a main constraint, there will be no direct CO_2 emissions, so carbon removal is not modelled for the islands (but this does not rule it out for the mainland). Given the high costs of direct air capture, electricity generation emitting CO_2 without capture (other than perhaps small amounts of unabated biomass) will have no place in a net zero energy system, other than possibly in the event of emergencies (National Grid, 2023). It is assumed that this will also apply to island demand sectors such as industry, which in the islands' case does not include energy intensive industries like cement or steel manufacturing. CCUS (including direct-air capture) has not been considered for the islands but is modelled for the mainland generation mix (Section 6.3). Although there is existing oil and gas infrastructure in Orkney (the island of Flotta) and Shetland (Sullum Voe) which could have potential for CCUS, the scale of island emissions relative to other regions make them unlikely to be developed as a priority before 2050 (Thomas, 2020). Heavier emitters on the islands suitable for CCUS would be needed to make projects viable, therefore it has not been considered. It should also be reiterated that the islands do not have a gas distribution network (other than in the isolated case of the town of Stornoway, which for simplicity has not been considered) (Scottish Government, 2017). Adjacent to this, uncertainty in the role of hydrogen is perhaps greatest of the main aspects described in Table 3-2, with results being more dependent on the assumptions described. The implications of this for results are discussed in Section 7.5 and Chapter 8.

Nature-based emissions mitigations of land use changes have not been modelled. In the UK, the two main land use changes relating to emissions are reforestation and restoring peatlands (CCC, 2023). Although these could be feasible for the islands, there are several issues which make them less suitable for the islands. The islands are constrained by land area firstly, with limited space to alter habitats compared with the mainland. For reforestation, the islands are generally a poor candidate given their exposure to the north Atlantic and thin soil cover. Under Scottish Government reforestation scheme in 2021, a total of 2.5 ha was planted in the Na h-Eileanan Siar, with none in Orkney or Shetland, against a total of 11,193 ha (Scottish Forestry, 2021). Given the poor climatic conditions relative to the mainland and the fact that reforestation would be in direct competition with farming as the main use of land currently (EDINA, 2021), the economic value of reforestation is unlikely to be attractive enough to incentivise it. The scope for peatland restoration would similarly be limited by its economic attractiveness, with peatland restoration costs in Orkney, Shetland, and Na h-Eileanan Siar averaging at least 50% higher than the national average (Glenk *et al.*, 2022). Considering the islands in isolation, the technologies could be economically viable, but when considered against options elsewhere in Scotland as they would be, they are unlikely to be competitive on price of avoided CO_2. Irrespectively, the scenarios are compared as extremes of technology configurations within the confines of the FES, not as cost-optimised outcomes. For the islands, which do not include any particularly hard-to-abate demand sectors, such nature-based solutions are also less likely to be necessary to balance the last few percentage points of emissions.

The other main assumptions of the model are described in Table 3-4. How these are implemented as model inputs is described in more detail in their relevant sections. The implications of these assumptions for results are described in Section 7.5.

Table 3-4: Main assumptions of the Net Zero model.

	Name	*Description*
Hydrogen	Fuel switching	There is no modelled fuel switching due to fuel prices - how demand is met is determined by technical considerations - see Section 4.
	Type of fuel	Hydrogen is used as a blanket term for hydrogen-based fuels, which could others such as ammonia or synthetic fuels.
	Blue hydrogen	Hydrogen produced from fossil fuels with CCUS is not modelled (see Section 3.4.2).
	Hydrogen storage	Liquefied hydrogen storage has been modelled for the islands due to the optimal cycling (DNV GL, 2019) matching the frequency of island fuel deliveries (Orkney Islands Council, 2022a). Geological storage is not considered (Katriona Edlmann, 2023). See Section 3.4.3.

	Name	Description
	Electricity price for hydrolysis	The price of hydrogen produced by islands electrolysis is not optimised in PLEXOS (Section 3.4.2)- instead the FES costs of hydrogen are used. The operation of electrolysis in the model assumes that excess renewable generation is available at an economical price for electrolysis to operate.
	Import costs	Imported hydrogen costs are 25% higher than produced locally or on the mainland, per existing fossil fuel prices (Orkney Renewable Energy Forum, 2014).
Networks	Mainland network constraints	The mainland is modelled as a single node with no transmission constraints.
	Network upgrade costs	PLEXOS only models connections between nodes, not the network within each node.
	EU inter-connections	Interconnections with the EU have not been modelled.
Demand	Rebound effect/ behaviour changes	The rebound effect or behaviour changes are not modelled for scenarios of efficiency improvements - see the introduction of Section 4.
	Replaced fossil fuels	All fossil fuel demand for the islands is replaced by electricity, biogas, or hydrogen.
	Meeting policy targets	The achievement of policy targets is met to varying degrees in the different demand scenarios - see Section 4.6.
	Hydrogen heating or transport	Hydrogen is not considered as a domestic fuel as the islands have no gas distribution network.
	Non-domestic building data	No non-domestic building fabric data was available, so it was assumed to have the same distribution as domestic.
	Mainland vs island demand	For simplicity, transport to the mainland (aviation and ferries) are assumed to refuel on the mainland.
Supply	Existing technologies only	No new technologies (SMRs, fusion, other renewables, etc) are in place before 2045.
	CCUS not suitable	CCUS is not modelled as a technology suitable for the islands - although Shetland could have long-term potential beyond 2045 (Thomas, 2020).
	Heat networks	Heat networks are not considered in the model due to generally rural nature of islands and the additional complexity.
Biogas	Co-digestion of waste	Co-digestion of the variety of the different island waste streams would be feasible and equivalent to separately digesting each.
	Competing resource demands	Other non-energy demands could have higher values uses for the biowaste.
Weather	Worst-case weather data	Worst-case weather data for UK and EU is used (Section 3.3.6), which might not be the same as for the islands.
Markets	Changes to market structure	The outcome of ongoing consultation on electricity market reform (BEIS, 2022i) is not considered.

3.6 Costing scenarios of technology deployment

The Net Zero model scenarios will be costed based on technology deployment for the main categories of demand, supply, networks, fuels (electricity and hydrogen), and curtailment. In all cases costs have been split into CAPEX and OPEX for the technology capacities described in each relevant sub-section in Chapters 4-6. Costs are based on unit costs applied to the technology capacity (MW, MWh, per m^2, per property, etc. depending on the relevant metric). Cost data has been taken from the most representative data source available. Single datasets, with a unified methodology, were used rather than collecting more geographically specific but disparately sourced values for each technology. For example, the UK-wide generation cost data from BEIS for gigawatt-scale wind farms is assumed to be fine for larger island generators but might be less representative of the smaller ones. To account for this, ranges of costs (High-Low) are modelled where a range was available. Elsewhere, it was assumed to range ±33% which is the range assumed in EPC improvement costings (Scottish Government, 2021b). Where specific costs are not given in this section, they are provided in Appendix B.1.

3.6.1 Demand costing

Costs were calculated for the demand model (Section 4) based on ranges of efficiency-based technologies for the three main demand scenarios (Section 4.6) and cost data (Table 3-5). The demand model covers the whole building inventory, so costs could be derived for each residence and estimated by floor space metrics for business establishments. High/low ranges are based on the EPC database improvements (Scottish Government, 2021b). Costs related to vehicular and industrial efficiency strategies were omitted. The heterogeneity of products and solutions specific to these sectors makes costing them highly complex and speculative. Furthermore, these costs are not commonly deliberated alongside measures such as building fabric enhancements or heat pumps. Justifying these policies is more likely to be politically motivated rather than economically, rendering cost comparisons harder to justify.

Table 3-5: Summary of cost data assumed.

Category	*Aspect*	*Description*	*Source*
Appliances	Appliance efficiency	Replacement of major appliances to specified energy rating for each household.	Appendix B.2
	Standby power		
Buildings	New build	Difference in new build EPC ratings equal to EPC costs.	(Scottish Government, 2021b)
	Building retrofitting	Cost from EPC database of costs to upgrade buildings.	
Heating	Heating electrification	Heat pump costs based on floor area; storage heater from EPC.	(Kokoni and Leach, 2021; Scottish Government, 2021b)
Transport & industry	N/A	N/A	N/A

3.6.2 Supply costing

Supply costs included generation, BESS, electrolysis, and hydrogen storage (Table 3-6). Details on the relevant cost data and sections for the capacities used is given below, with specific values given in Appendix B.4.

Table 3-6: Capacity and cost data used to calculate overall costs for each category of supply.

Aspect	*Cost calculations*	*Cost data ref.*	*Capacity section ref.*
Generation	Installed capacity (MW or MWh) x unit costs (£/MW or £/MWh)	(BEIS, 2020b)	Section 6.5
BESS		(BEIS, 2018b)	Section 6.5.4
Electrolysis		(BEIS, 2021a)	
Hydrogen storage		(DESNZ, 2023h)	Section 7.3.1
Biogas	See Section 5.4 for cost calculations		Section 5.6

Generation, BESS, and biogas have the lower variability in unit cost due to the technologies and their functions in a potential 2045 net zero energy system are clear. For electrolysis and more so for hydrogen storage however, the range of uncertainty is greater (see Section 7.4). Costs for electrolysis have been assumed as the average of costs for three technologies - alkaline, proton membrane exchange, and solid oxide electrolysis. For hydrogen storage, only liquified storage has been included, assuming cheaper geological storage is not available on the islands (Section 3.4.2).

3.6.3 Networks costing

Further distribution and transmission upgrades are only considered in the BAU scenario. Costs for planned or under-construction network upgrades (such as the Shetland interconnection) (SSEN, 2020a) are considered to be equal between all scenarios so have been omitted.

Network costing is less certain than the other aspects due to an uncertain scope of works from modelled results. Transmission constraints have been identified based on network shapefiles, giving nodal areas used to split up the inputs from the other models and structure the Net Zero model (Section 3.4.5). Nodal areas capture the main constraints from ANM systems, but more network detail than the interconnections between nodes (which themselves contain electricity networks) is not captured. Therefore, the only thing that can be determined with certainty is that line connecting nodes would need upgrading, but not if the network within the node would also. To compare outcomes, two extremes of network upgrade costs are calculated using average costs of £3.5m/km for overhead and £16.9m/km for underground (Parsons Brinckerhoff, 2012).

Low estimate: only the upgrading of the specific lines connecting nodes (identified as network constraints in the shapefiles) are costed. It is assumed that these are the only areas of constrain and the network within each PLEXOS node has sufficient capacity to deal with additional demand and supply.

High estimate: all the network capacity >33kV within nodes that require an upgraded network require upgrading. By length, the islands network is 77% 11kV, 20% 33kV, and 3% 132kV (SSEN, 2019), meaning this scenario equates to 23% of the total network (for nodes identified as requiring network upgrades) having its capacity upgraded.

3.6.4 Fuels and curtailment costing

The two fuels modelled for the islands (electricity and hydrogen) are costed based on projected fuel prices (Section 3.4.1) and modelled island demand (Table 3-7).

Table 3-7: Summary of prices assumed for fuel cost calculations.

Aspect	*Cost (£/MWh)*			*Reference*
	Low	*Mean*	*High*	
Biogas	Calculated in Chapter 5			-
Hydrogen	120.0	235.0	350.0	(National Grid, 2023)
Electricity	58.0	72.5	87.0	(BEIS, 2022c)
Curtailment	100	200	300	(de Berker, 2024)

The price for hydrogen imported to the islands has been assumed to be 25% higher than the mainland or produced locally, consistent with the current fossil fuel markup for the islands due to additional transport costs (Orkney Renewable Energy Forum, 2014). What curtailment payments could look like in 2045 is unclear, but it is not mentioned in proposed market reform (BEIS, 2022i). Assuming it will be equivalent (intermittent generation constrained by network capacity paid to reduce output, with more expensive dispatchable generation closer to demand paid to meet demand), it has been included based on historic prices. The implications of this for modelled electrolysis dispatch (with modelling assuming electrolysis operating on free electricity otherwise curtailed) (BEIS, 2021a) is discussed in Section 8.2.3.

4 Whole system demand modelling of the islands

The demand model presented in this section has been developed to consider all demand sectors in the Net Zero model (Chapter 3 and 7). To avoid sampling bias, it considers 100% of the population, businesses, buildings, and demand sectors. To address issues raised in the literature of data availability and human behaviour, time use data (Gershuny and Sullivan, 2017) is used for domestic and commercial demand modelling. The integration of a diverse set of databases, data science techniques, and other models are outlined in this chapter. The model is based on, adapts aspects from, and combines several main methodologies:

(i) DEAM for the general structuring of domestic and non-domestic categorical demand (Spataru and Barrett, 2016);

(ii) SimStock for building heating and lighting demand (Steadman *et al.*, 2020);

(iii) Combinatorial optimisation for generating a synthetic population (Huang and Williamson, 2001);

(iv) Time use survey data (in combination with the above) to create domestic electricity demand profiles (Thorve *et al.*, 2019) – adapted here to include non-domestic demand;

Two main aspects have been modelled separately - demand expected to be electrified and the remainder. Demand categories such as freight vehicles, farm vehicles, ships such as inter-island ferries, and industrial demand (primarily distilleries) are technically unlikely to be electrified (IEA, 2022b). Air transport and public administration transportation have not been modelled due to lack of data (for Orkney in 2014, they both made up only 4.6% of transport sector demand) (Orkney Renewable Energy Forum, 2014). Ferries to the mainland are assumed to refuel on the mainland, so are not included. All other domestic, commercial, and industrial demand has been assumed to be electrified (National Grid, 2023) and is modelled.

The electricity model is validated with recorded GSP demand data from the Scottish islands for 2016, as detailed in an Energies publication (Sections 4.1, 4.2, 4.5, and parts of 4.8) (Matthew and Spataru, 2023a). The model's capability extends to generating demand scenarios based on various technologies and efficiency policies, with the results and policy implications forming another work (Sections 4.6, 4.7, and parts of 4.8) (Matthew, 2024b). While the model also provides insights into specific demand implications, its primary outputs consist of demand profiles for electricity, heating, and hydrogen across domestic, non-domestic, industrial, and transport sectors. These are used as inputs to the overall Net Zero model in PLEXOS to capture energy efficiency implications. Although the Demand model includes precise categories (e.g. cooking, cleaning, refrigeration, etc.), they are not required as PLEXOS inputs.

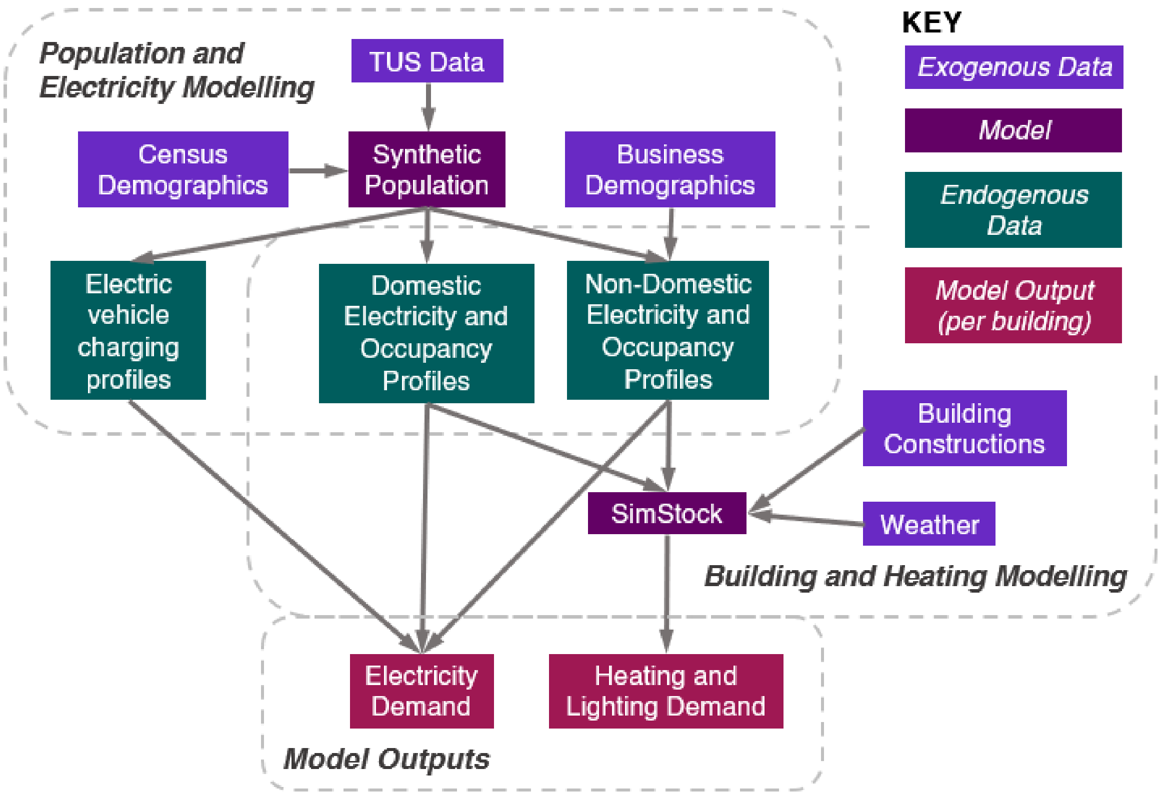

Figure 4-1: High level overview of the electricity and heating model (Matthew and Spataru, 2023a).

The main datasets used for domestic and commercial sectors are time use (Gershuny and Sullivan, 2017) and census data (National Records of Scotland, 2016) (Figure 4-1). Demographic characteristics identified in the literature were used to create a synthetic population of households from the time use individuals. Time use activities are converted into hourly electricity demand profiles using recorded appliance demand (Intertek, 2012). For commercial electricity demand profiles, the model takes into account business demographics, operating hours, and the synthetic population's occupancy patterns integrated with energy floor space factors (BEIS, 2016a).

Building construction types, weather data, heating behaviour, and occupancy profiles sourced from the synthetic population are also incorporated. These inputs are utilised by SimStock (Ruyssevelt, 2019), which simulates heating and lighting demand with EP (U.S. Department of Energy, 2020). Demand is calculated for each individual household and business for individual categories (Figure 4-2). Combined heating, lighting, and appliance demand results in an overall demand for each property. These property-level demands have been aggregated at different spatial resolutions to validate the model. A comprehensive list of the databases utilised is provided in Appendix A - all datasets are available freely under an academic license, unless stated otherwise. The estimated annual demand data by property and scenarios (described in Section 4.6) is available in shapefile format on ArcGIS online (Matthew, 2024a).

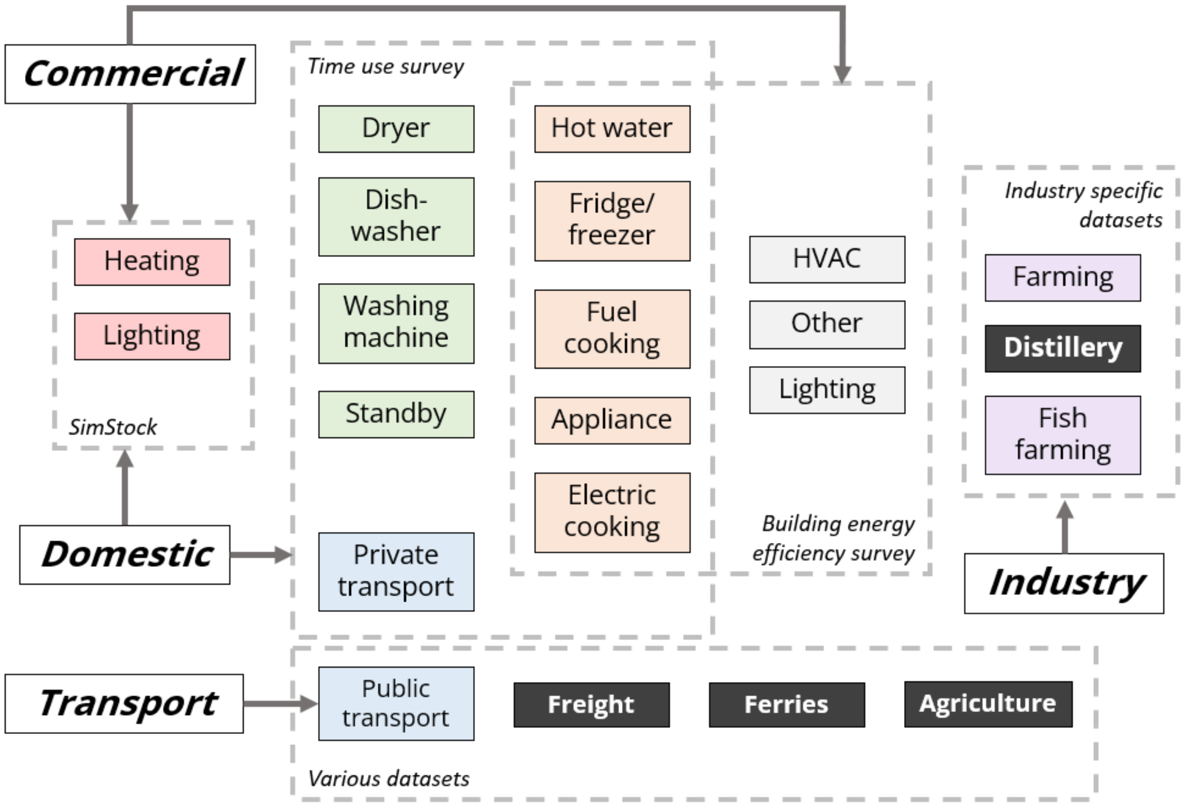

Figure 4-2: Categories of modelled demand for domestic, commercial, industry, and transport sectors. Sections with white text are assumed to be met by hydrogen- see Section 3.3.

The demands of sectors not anticipated to be electrified (IEA, 2022b) have been modelled separately (see Section 3.3). Although there is considerable debate in the UK surrounding use of electricity or hydrogen for building heating, only electrification of heating is considered. As the Scottish islands lack a natural gas network, a new network for hydrogen would be infeasibly expensive. For simplicity and to manage the number of scenarios, private transport and public transport (i.e. buses) are assumed to be electrified, whereas heavy transport converted to hydrogen. As combined databases were not available for these sectors, so demand has been aggregated from specific freight/ HGV transport, farming, public transport, ferries, and whisky industry databases (Section 4.3).

Behavioural changes affecting energy demand are not considered in the model due to being difficult to predict - only changes in technologies used to meet demand. Demographic data is used to model specific behaviours affecting energy demand, but not how this could change over time or in relation to new technologies. While behavioural changes have altered energy demand over the last several decades, the timing of use (day time peaks and an over-night trough) has not changed significantly (Anderson and Torriti, 2018). For annual demand, given the scale of changes required to decarbonise (particularly heating and transport), these changes are likely to dwarf changes in home appliances usage. How peak demand changes will be dictated by the uncertain take-up of DSR, but again, the scope of this is likely to exceed behavioural changes. By its economic definition, if DSR is properly set up and managed with a wide enough participation, price-signals should only minimise peak demand increases. Other changes though, perhaps due to hourly tariffs or other policies are uncertain. The implications of this for the projected scenarios of demand are discussed in Section 7.5.4.

The novelty of the work presented in this chapter consists of the following:

(i) *Open-source data:* to avoid the data privacy issues associated with recorded demand profiles, statistically representative synthetic data has been developed from freely available datasets (summarised in Appendix A).

(ii) *Time use data for non-domestic occupancy profiles:* time use data, which has been widely used for domestic energy modelling, is here adapted such that the synthetic population developed can also be used to generate non-domestic building occupancy profiles which are lacking in the literature.

(iii) *100% sample, bottom-up, and hourly building demand:* the model captures the hourly demand by category of the whole population, allowing an understanding of how changing technology configurations affect overall demand. This improves on previous 100% sample models which generally only consider annual demand.

4.1 Time use data for domestic, commercial, and transport electricity demand

To model behavioural and demographic factors influencing domestic and commercial demand, time-use survey and census data have been used to represent the actual population. Domestic variables include household size, age distribution, employment status, and deprivation indicators - commercial variables include business types and their respective opening hours. Time-use data has traditionally been used in domestic demand models. This chapter expands its applicability by using it to generate specific profiles for both domestic and commercial occupancies - industrial demand is treated separately (Section 4.1.3).

4.1.1 Domestic electricity demand

The flow chart for the electricity demand model refers to specific methods and datasets (Figure 4-3). Combinatorial optimisation is used to sample from small area census microdata to create a synthetic population matching the statistical distributions of specific areas (Huang and Williamson, 2001). There are five main steps:

(i) Appliance demand data is combined with ten-minutely time use data to create a database of hourly, categorical demand for each time-of-use household.

(ii) A synthetic population is generated using combinatorial optimisation from known island census statistics and the microdata, ensuring that dependencies between household characteristics are maintained. This and step one are based on a previous demand simulation methodology (Thorve *et al.*, 2019).

(iii) The synthetic population is matched via the relevant characteristics (Table 4-2) to the time use demand profile database.

(iv) These demand profiles, combined with building stock data (Section 4.2) are used as inputs to SimStock to calculate heating and lighting demand.

(v) Demand is combined at various resolutions to validate the model against recorded demand data.

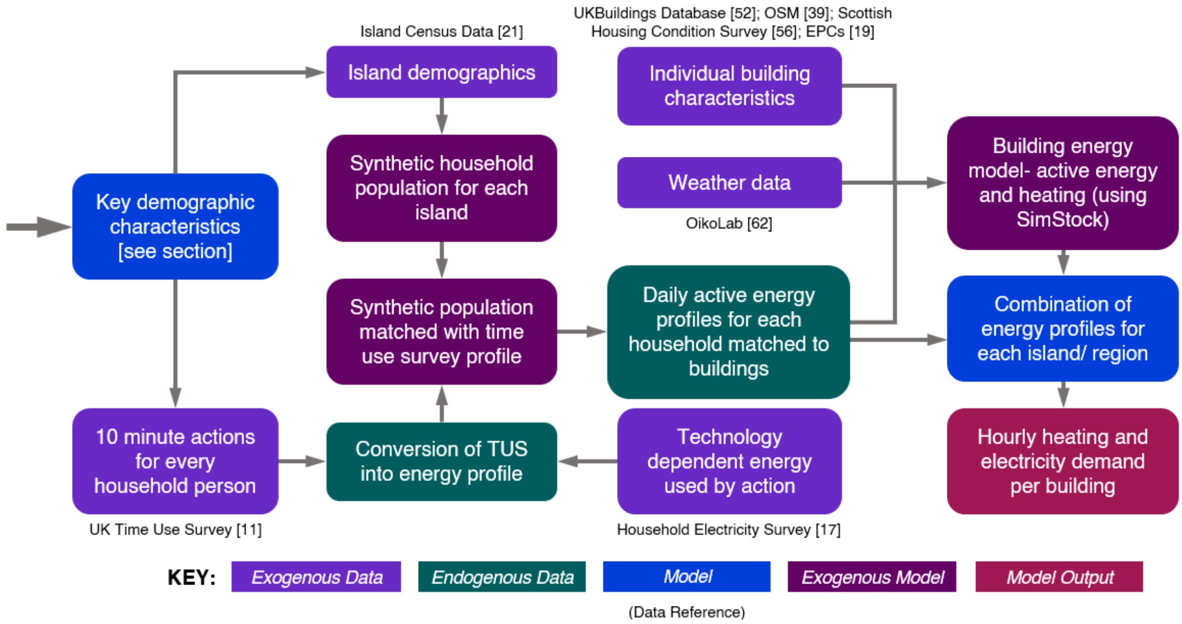

Figure 4-3: Flowchart of the domestic model (Matthew and Spataru, 2023a).

The time use data records actions and locations of 11,421 respondents in 10-minute intervals over one day (Gershuny and Sullivan, 2017). Individual actions were categorised by electricity usage, and then combined into household profiles using an algorithm to align the use of shared household appliances (e.g. washing machines and dishwashers) with household ownership data (Thorve *et al.*, 2019). Household actions were merged with surveyed annual consumption data for major household appliances (Intertek, 2012) to create categorised hourly electricity demand profiles per Table 4-1. Hot water demand was linked to time use data actions using annual data from a separate survey of hot water demand measurement (Energy Saving Trust, 2008)

Table 4-1: Domestic energy categories.

Appliances	Laundry	Cold appliances
Electrical cooking	Dishwashing	Lighting [1]
Fuel-dependent cooking [2]	Standby	Hot water [3]

[1] *EP was used to calculate hourly lighting demand (Section 4.2.4);*
[2] *For the model validation, the calculation of electrical heating demand was dependent on the heating fuel (Section 4.2.2);*
[3] *Immersion water heating was considered by adjusting the demand to overnight (00:00-07:00).*

To account for the influence of household demographic data on energy demand, census demographic data was used to select specific time use electricity profiles from the time use energy demand database. Combinatorial optimisation (Huang and Williamson, 2001) was utilised to generate a synthetic population statistically representative of the islands' demographics:

(i) An initial sample of households from the time use data was taken totalling the population of the region.

(ii) A random household is replaced from the main database and the new sample evaluated against census statistics (National Records of Scotland, 2016).

(iii) If the replacement improved the score, the household was kept; otherwise, it was discarded.

(iv) Repeat steps *(ii)* and *(iii)* until a threshold score is reached

This sample of households then has categorical electricity demand profiles aligned with the demographic characteristics recorded in the census data for each island. Other household attributes, such as the number of rooms per person and type of accommodation, were later used to match households to specific buildings (Section 4.2.1).

Table 4-2: Census demographic characteristics modelled.

	Demographic Characteristic	*Categories*
Individual	Age (Brounen, Kok and Quigley, 2012; Lorimer, 2012)	<18; 19-64: >64
	Hours worked per week [1]	<15; 16-30; 31-48; >48; N/A
Household	Size of household (Brounen, Kok and Quigley, 2012; Lorimer, 2012)	1; 2; 3; 4; 5; 6; >7
	Number of persons per room (Lorimer, 2012; Morris *et al.*, 2016)	< 0.5; 0.5-1.0; 1.0-1.5; >1.5
	Number of deprivation indicators (Druckman and Jackson, 2008; Brounen, Kok and Quigley, 2012; Morris *et al.*, 2016)	0; 1; 2; >3
	Type of accommodation (Gesche M. Huebner *et al.*, 2015; Ahmed Gassar, Yun and Kim, 2019)	Detached; semi-detached; terrace; flat/maisonette/other

1 This was to assign individuals to places of (see Section 2.2), not energy demand specifically.

Demographic characteristics were identified in the literature as influencing energy demand (Table 4-2). These characteristics were directly mapped between the census and time use demographic data, except for the deprivation indicators. These encompass factors such as employment status, receipt of benefits, crowdedness, long-term health conditions, and education status, which were counted in accordance with published guidance (Scottish Government, 2016).

4.1.2 Commercial electricity demand

The commercial model (Figure 4-4) similarly creates demand profiles per property. The synthetic population developed in the domestic model was also used for commercial occupancy profiles, ensuring that individuals and building occupancy profiles were only counted once between the domestic and commercial buildings and improving on the standard occupancy profiles assumed in other models. Steps include:

(i) Individuals are matched by opening hours and time spent at work to commercial properties.

(ii) Occupancy profiles, business demographic data, and floor space energy factors were used to create demand profiles for each building/business.
(iii) Lighting and heating are modelled using SimStock (Section 4.2).
(iv) The model is validated by combining data at various resolutions.

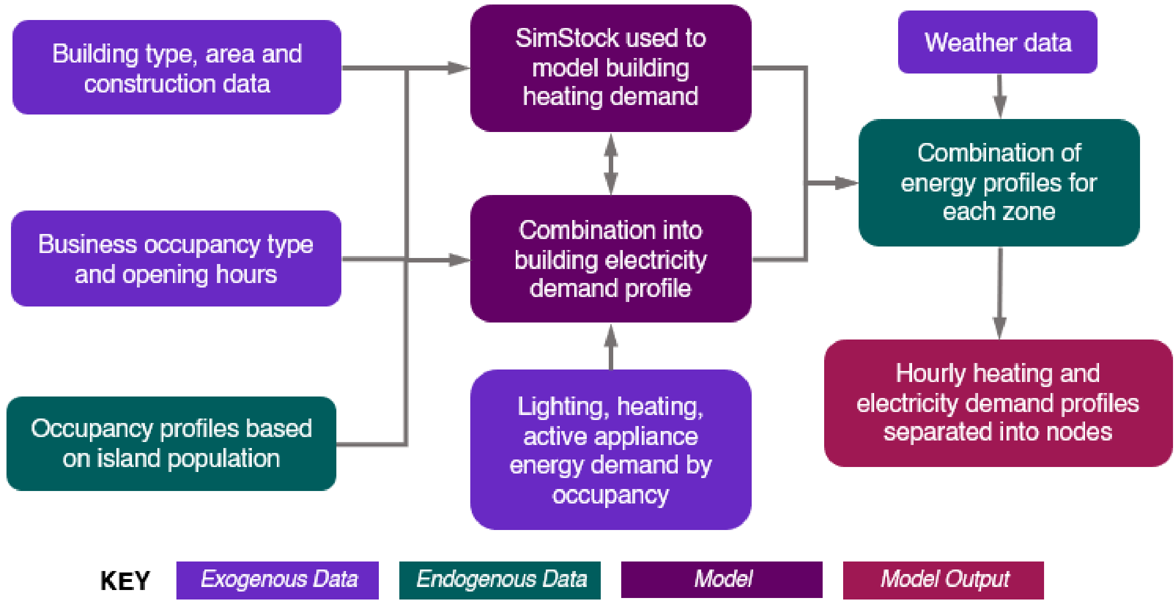

Figure 4-4: Flowchart of the commercial model (Matthew and Spataru, 2023a).

OSM occupancy type data was used for business types (OpenStreetMap contributors, 2021). To match occupancy profiles with categories found in the Building Energy Efficiency Survey (BEES) (BEIS, 2016a), the 51 OSM categories were mapped to those listed in Appendix B.2. Occupancy-specific opening hours from Google Places API (Google, 2021) were sampled based on the occupancy type and then assigned to the building database (Section 4.2).

The database of businesses and opening hours were then matched with synthetic population individuals, by adapting the combinatorial optimisation method previously used for domestic populations.

(v) Synthetic population individuals were randomly assigned to commercial properties with employee density estimates (Office of Project & Programme Advice & Training, 2010) to ensure employees were distributed fairly.
(vi) Random individuals then swapped places.
(vii) How much time everyone spent at work from the time use data was scored with the business opening hours.
(viii) If the new assignment resulted in an improved score, the match was kept; otherwise, it was discarded.
(ix) Steps (ii) and (iii) were then repeated until a threshold score.

By combining the synthetic population occupancy profiles with business opening hours in this way, commercial occupancy profiles could be represented that are not readily available in the literature. Using the same overall synthetic population means that individuals and their actions were not duplicated between the domestic and commercial models.

To transform the opening hours and occupancy types into hourly energy profiles, floor space energy factors (kWh/m2) specific to each occupancy type were used from BEES (BEIS, 2016a). The annual energy per floor area was grouped and categorised into two main types: baseload and occupant-related (Firth *et al.*, 2008). Baseload includes refrigeration, other (including miscellaneous categories specific to certain occupancies, i.e. swimming pool for leisure centres), and HVAC. Insufficient data on HVAC and other categories required them to be considered as baseload. Baseload demand (W) categories were calculated using Eq. 4-1, with floor areas from the buildings database polygons (Section 4.2.1):

$$Baseload\ Power = \frac{E_{annual}\ \times A}{8760} \qquad \text{Eq. 4-1}$$

E_{annual} = annual demand per area (kWh/m^2); A = property area (m^2).

Occupancy-based demand, including catering and appliances, were modelled using the derived hourly business occupancy profiles. The annual energy consumption was assumed to occur over the course of a whole year, considering the total hours of occupancy. Throughout the hours of a typical day (h - Eq. 4-2), the occupancy profile $f_{occ}(h)$ ranges 0-100%. The number of synthetic population individuals assigned to a property were used as a proportion of the maximum occupancy utilising maximum floor space factors (Office of Project & Programme Advice & Training, 2010). This yielded a fraction of the estimated energy consumption according to BEES data considering reduced occupancy at any specific time interval. This is described in Eq. 4-2, where solving for the peak energy ($\dot{E}_{peak}$) yields the occupancy-based energy profile for each building. This process was repeated for every day of the week with available opening hours.

$$E_{annual} = \int_{0}^{8760} \dot{E}_{peak}\ \times f_{occ}(h) \qquad \text{Eq. 4-2}$$

4.1.3 Industrial electricity demand

Whisky distilling, farming, and fish processing were known to be the major energy-intensive industries on the islands (Ricardo Energy and Environment, 2019), however specific energy factors were not available. Annual energy demand for these was estimated based on production data (given in Appendix B.3). For the twenty-seven island distilleries, production was used to allocate the demand to the corresponding properties for each facility. Detailed information regarding the temporal specificity of demand was also lacking, so it was assumed that production was continuous, excluding a month break in the summer for maintenance.

Specific data was not available for farming or fish processing, so production data was used to calculate an annual energy density value (kWh/m^2) applied to each property. For fish processing, the energy demand was assumed to occur during the property opening hours, per the commercial methodology. Farming demand was modelled with measured seasonal variability (Shortall *et al.*, 2018).

Additionally, historic demand data for water treatment was incorporated through a freedom of information request (Scottish Water, 2022a).

4.1.4 Private and public transport electricity demand

Per other studies (Dixon and Bell, 2020; Ramirez-Mendiola *et al.*, 2022), private transport demand electrification is included using the time use data (Gershuny and Sullivan, 2017). The algorithm employed for modelling electric vehicle (EV) charging demand is described in Figure 4-5.

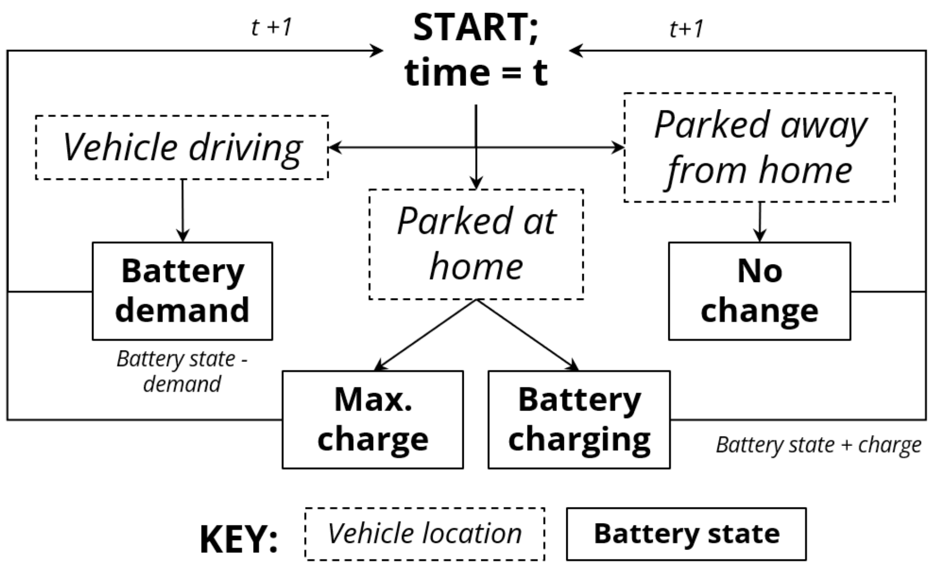

Figure 4-5: Algorithm used to model transport demand charging profiles based on time use locations (Matthew, 2024b).

Each timestep determines whether the vehicle is charging (with home assumed to be the only charging location for simplicity), producing a demand on the battery (when driving) or not in use (parked away from home). The location data, reformatted into these three categories, was utilised with the technical data in Table 4-3 to apply a demand on the battery or a charging load (applied until the daily demand had been met). The model simplistically assumes an average charging demand independent of the size of the EV battery. It also assumes that vehicle owners plug in their cars to charge as soon as they return home. This approach has been shown to facilitate significant cost savings for households through increased Vehicle-to-Grid (V2G) charging opportunities (Dixon *et al.*, 2022), making it a strategy that should be considered in models and encouraged through targeted policies.

Table 4-3: Technical characteristics used to model EV and bus charging profiles.

Aspect	*Value*	*Units*	*Reference*
Average speed [1]	38.6	km/h	(Department for Transport, 2023)
Vehicle efficiency	0.25	kWh/km	(IEA, 2023)
Average battery demand per hour	9.65	kWh	Average speed x efficiency
Peak charger load	7	kW	(IEA, 2023)

1 Note that there are no motorways on the islands so the average for A-roads has been used.

The model includes public transport demand through focusing on local bus demand assumed as electric rather than hydrogen for simplicity. Annual local authority bus demand (BEIS, 2022h) was distributed based on bus routes. A database was created by manually extracting data from every bus timetable on the islands, including the number of circuits per weekday/weekend, the distance per circuit, and the start/end times (Appendix B.2). The total distance travelled for each bus route was then used to allocate the local authority annual demand for each island. The start/end times of buses were utilised to approximate when they would be charging, assuming that when not in transit, they would be plugged in, in line with the representation in Figure 4-5.

4.1.5 Tourism demand seasonality

To estimate the fluctuation of seasonal tourism, monthly passenger statistics from several sources were combined. These sources included the West coast ferry operator (CalMac Ferries, 2021), the Northern ferry operator (NorthLink Ferries, 2020), and data from the Civil Aviation Authority for airports (UK Civil Aviation Authority, 2021). This collected data allowed estimation of total monthly visitors per local authority. This was combined with visitor surveys (Visit Scotland, 2023), which had breakdowns of the proportion of passengers local to the island and tourists who would be staying in non-energy using accommodation (e.g. campgrounds). These population changes were included by duplicating random households in the synthetic population.

4.1.6 Temperature based seasonality of demand

Recorded demand data shows fluctuations over a year, particularly for heating and cooling appliances (Intertek, 2012). This was approximated by assuming a linear relationship between temperature and the proportion of energy consumed (Figure 4-6). The appliance energy demand was then adjusted based on the local temperature. Building heating and lighting seasonality was calculated separately using EP.

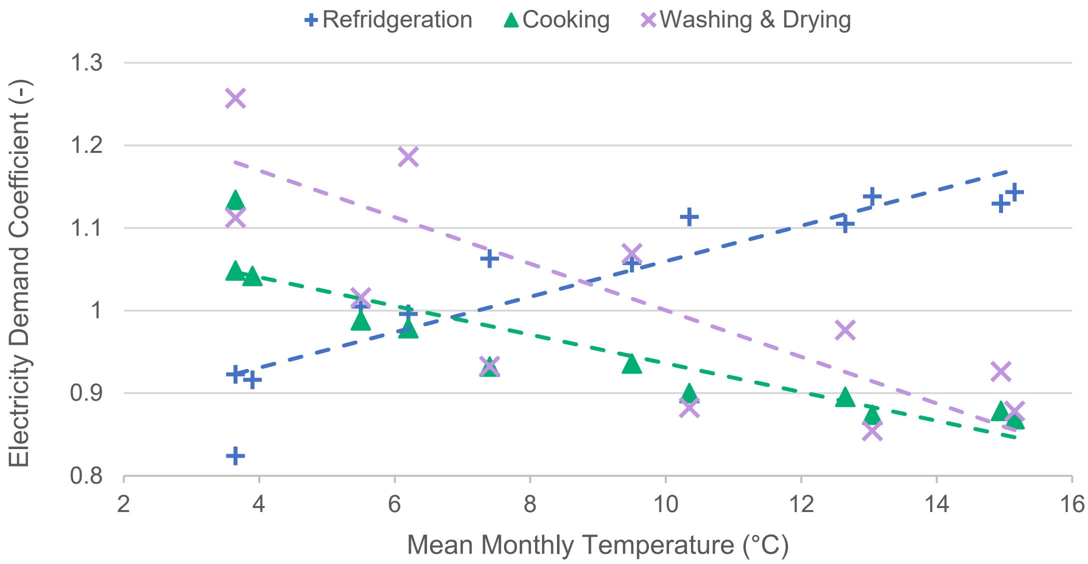

Figure 4-6: Average variation in demand by temperature extrapolated from monthly variability (Intertek, 2012).

The temperature dependency of EV charging efficiency was included by adjusting the demand by a factor based on the local temperature (Lindgren and Lund, 2016). This considers the increased demand of EV charging during cold periods which coincides with peak demand.

4.2 SimStock for heating and lighting demand

Lighting and heating demand calculations (Figure 4-7) were performed in SimStock (Ruyssevelt, 2019). Building data from UKBuildings (Geomni, 2020) and OSM (OpenStreetMap contributors, 2021) databases was consolidated using the unique property reference numbers (UPRNs) and building types. Recorded statistical distributions related to building characteristics, including building construction (Scottish Government, 2021b, 2021c), time use occupancy profiles, heating behaviours (Huebner *et al.*, 2013b), and weather data (Oikolab, 2021) were then assigned using combinatorial optimisation. The SimStock framework (Ruyssevelt, 2019) takes this combined tabular data to transform each building, subdivided into properties, into an input file for EP, a software used to calculate heating and lighting demand (U.S. Department of Energy, 2020).

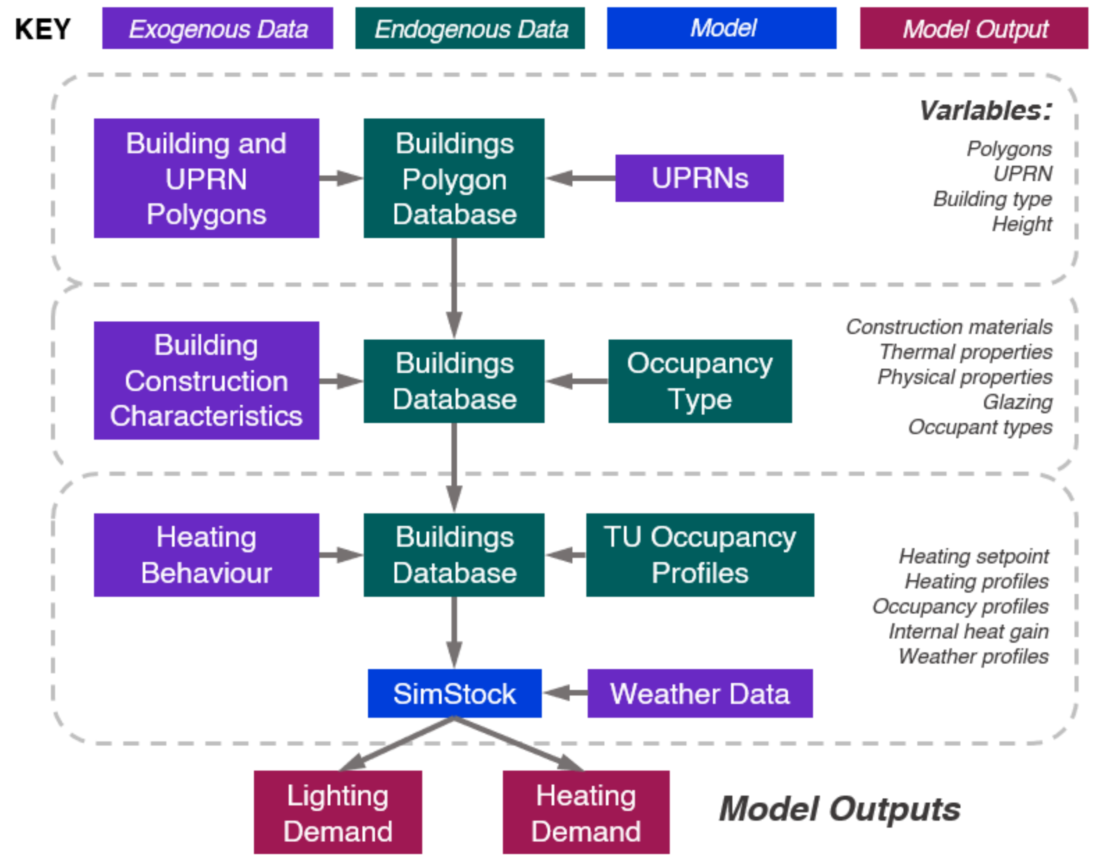

Figure 4-7: Heating and lighting model workflow to develop the database used by SimStock (Matthew and Spataru, 2023a).

4.2.1 Building type and polygons database

Building polygons were aggregated from two sources. The UKBuildings dataset combines data sources to cover 98% of buildings in the UK (Geomni, 2020), but with reduced coverage in the rural Scottish islands. To address this, it was combined with OSM (OpenStreetMap contributors, 2021) database which is updated by volunteers and had improved accuracy of building classifications. They were both combined, requiring extensive data cleaning.

Comparison between statistical distributions of domestic household floor areas (Scottish Government, 2021b) and the combined database revealed extensive misclassification in UKBuildings of large agricultural building types as domestic (but rarely the reverse). Large buildings (>1000m^2) were manually reviewed in Google Maps using their coordinates (Google Maps, 2020), with those being agricultural sheds being removed. For smaller buildings, as farm buildings typically formed isolated rural groups, a machine learning clustering algorithm was used. DBSCAN clustering was selected due to not requiring a specific number of clusters, is suited to arbitrary clusters, robust to outliers, and its ease of use based on the epsilon input value (Ester *et al.*, 1996). The model was trained using known farm locations and then applied to predict which adjacent buildings would belong to the same cluster of farm buildings. This process was also repeated for distilleries manually identified in Google Maps (Google Maps, 2020), as a major industry and also having significant complexes of buildings labelled “domestic”. These clusters, as well UKBuildings categories of "domestic outbuilding" and "unknown" were excluded from heating and lighting calculations in SimStock, improving similarity with measured domestic floor areas (Scottish Government, 2021b).

While the OSM database does not have the same geographical coverage as UKBuildings, it has better divisions for shared occupancy buildings (e.g. terraced houses), which divided more clearly into individual properties. In cases where multiple OSM polygons corresponded to a single UKBuildings polygon, the OSM data took precedence.

This merged buildings database then assigned UPRNs to each polygon (Ordinance Survey, 2021). Singular UPRNs per polygon were matched, but many had multiple UPRNs per polygon. As additional polygon detailing for buildings with multiple UPRNs were lacking, a method using Python was developed based on a POSTGIS tool (Praliaskouski, 2017). This evenly divided complex, non-convex building polygons into separate polygons for each UPRN, which although imperfect provided an improvement on the otherwise available polygons and allowed for mixed-use buildings recognised as significant in the literature (Steadman *et al.*, 2020). There were four steps (Figure 4-8):

(i) Points are evenly assigned to the polygon.

(ii) Points are grouped with spectral clustering, as the originally suggested k-means clustering (Praliaskouski, 2017) performed poorly for long, thin, non-convex polygons, where UPRNs were shared across empty space.

(iii) The boundaries between cluster centroids are drawn using a Voronoi diagram.

(iv) The intersection of these boundaries with the original polygon creates new polygons for each UPRN.

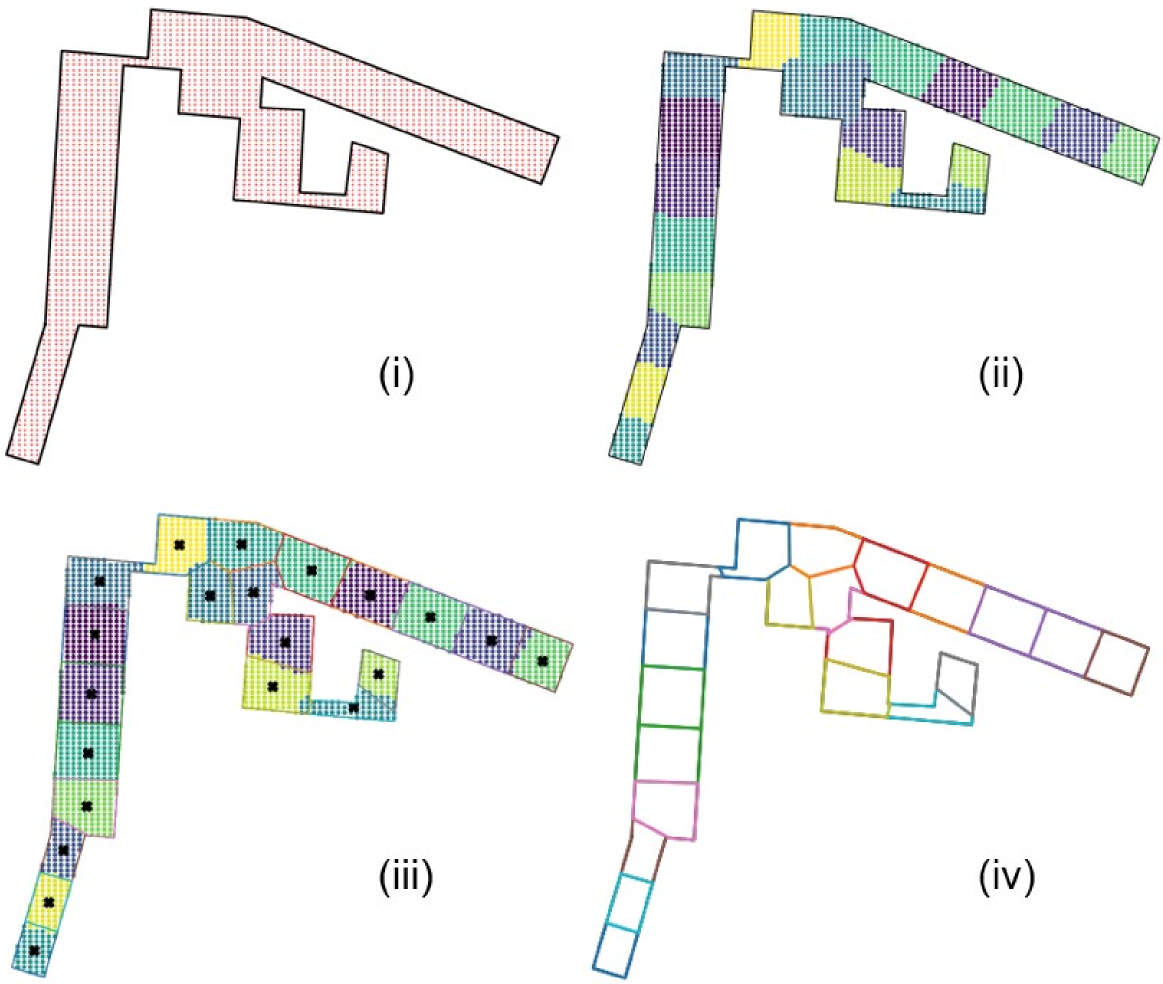

Figure 4-8: The polygon splitting process, described above.

4.2.2 Representative building characteristics

Building characteristics (wall, floor construction, roof, heating fuel, window type, and heating system) were added from the domestic (Scottish Government, 2021b) and commercial (Scottish Government, 2021c) EPC register using combinatorial optimisation (Section 4.1.1). EPC properties were selected to match surveyed building statistics for local authority areas (UK Data Service, 2022) based on the local authority, banded floor area, and type (flat, detached, semi-detached, and terraced). The construction types from the EPC database were converted into physical characteristics used as inputs for SimStock.

Commercial EPCs did not contain information on building fabric; only details on fuel and renewable energy types, meaning that domestic EPCs had to be used. For the predominantly rural Scottish islands, where 54% of non-domestic buildings are single-story (Scottish Government 2021a), this approach is likely a reasonable approximation, however it may be less suitable for more densely populated urban areas.

Glazing ratios, a vital building construction aspect, were missing data for both domestic and commercial properties in the EPC and SHCS datasets. For domestic buildings, a value of 20% was assumed based on a small-scale survey of non-domestic buildings (Gakovic, 2000) as the closest approximation. Better data availability for glazing ratios is needed, as it is a significant factor impacting modelled final energy demand (Calama-González, Suárez and León-Rodríguez, 2022).

4.2.3 Heating demand profiles

Recorded temperature profiles and demand hours for domestic heating were incorporated from surveys. As EP calculates the energy required to heat a building to a certain temperature, instead of using heating setpoint temperatures, recorded temperatures in households were instead utilised (Huebner *et al.*, 2013b). Commercial temperature data was available for seven occupancy types (Meng and Mourshed, 2017), which was extrapolated to the thirty-four modelled occupancies as the best available estimate. The extent of variations between these occupancy types remains unclear, particularly considering the limited sample of 119 properties in the survey.

Boiler and heat pump operations consist of three categories: daytime, bimodal, and continuous (Gesche M Huebner *et al.*, 2015) (Figure 4-9). The distribution of these modes varies by technology, with heat pumps being three times more likely to operate continuously, so heating technology was used to assign profiles to each property.

$$Storage\ heating = Annual\ mean - Summer\ mean - Nonstorage\ heating \quad \text{Eq. 4-3}$$

However, 60% of island electric heating is currently electric storage heaters (Scottish Government, 2021b), so their profiles could have a significant effect on model validation. Unfortunately, recorded operational data was unavailable, so daily demand profiles for storage heaters were estimated using Eq. 4-3 and recorded islands demand data (SSEN, 2021). This involved subtracting the hourly-day average summer demand (i.e., the average annual demand without heating) and non-storage heating from the recorded day-averaged total demand, resulting in a main peak overnight and a second in the early afternoon.

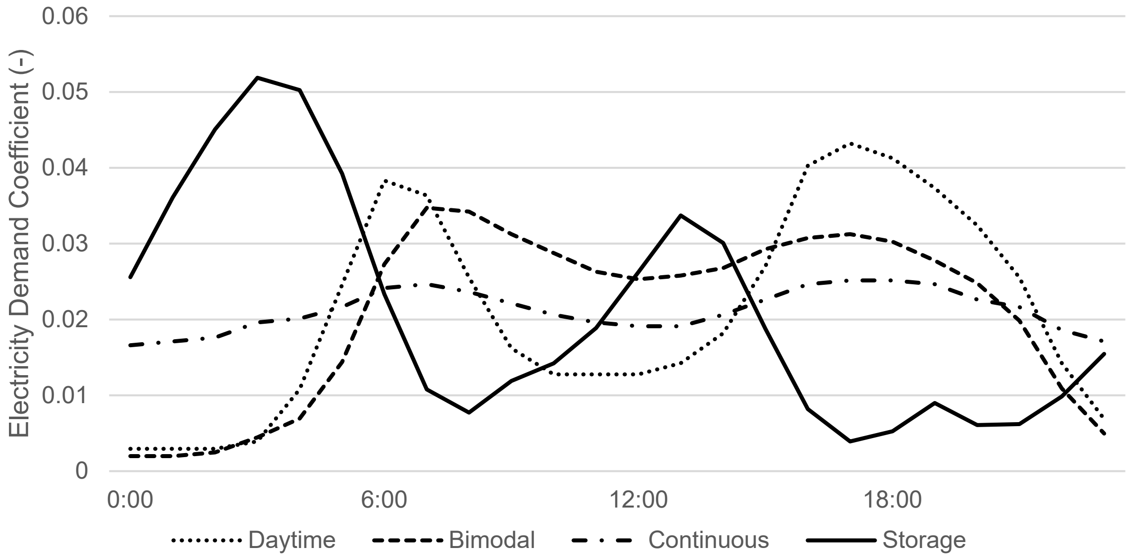

Figure 4-9: Daytime, bimodal, continuous (Gesche M Huebner *et al.*, 2015)*, and storage heating profiles modelled.*

4.2.4 Heating model calibration

Heating demand data was combined with the non-heating electricity demand to calibrate it compared with recorded data. Non-heating demand was aligned with recorded data from the appliance (Intertek, 2012) and non-domestic (BEIS, 2016a) surveys. The domestic heating model is calibrated to align changes in the EPC rating with recorded differences in under or over-heating (e.g. accounting for underheating in low EPC performing homes) (Few *et al.*, 2022). It was then compared with GSP electricity demand data in the summer (i.e. without significant heating demand). Hot water demand was calibrated using summer demand patterns, especially relevant for most island households with electric immersion heaters.

The air change rate was used to calibrate the heating, per EP modelling literature (Calama-González, Suárez and León-Rodríguez, 2022). This EP variable represents the ingress of air or airtightness of a building, and so the energy required to heat a space. The air change rate was calibrated to optimise seasonal heating demand compared with recorded demand. This highlighted that consistent heating setpoints throughout the year led to over-heating in the autumn and under-heating in the spring. Domestic and commercial non-heating electricity demand should not exhibit as much a significant seasonal variation compared to heating (except for farming, which peaks in the spring and is accounted for in the model). The model accounts for changes in the population due to tourism, which does not start to rise until early summer.

The only remaining factor affecting error in seasonal demand was heating demand. This seasonality of heating demand, where individuals tend to increase or extend thermostat settings after winter compared with after summer, was found to have been observed in previous studies (Wright, 1997; Pullinger *et al.*, 2022). Consequently, heating setpoint temperatures were adjusted by +1°C in the spring, +0°C in the winter, and -1°C in the autumn to compensate. This improved the accuracy of the model, reducing the spring and autumn over-prediction of heat demand. Further calibration could be possible with more work, but surveyed data on heating demand would be needed.

The heating model tended to overpredicted peak heating demand. EP calculates the energy to heat up an entire dwelling to the set temperature, without considering heat dispersion within the property (e.g. heat is not evenly distributed throughout a building - only room containing the thermostat might achieve the setpoint temperature) or the heating system's maximum capacity. The absence of an upper boundary on the heating system's capacity could explain the overestimation of peak heating demand, as poorly insulated buildings might not achieve the target temperature at peak system capacity. Peak heating demand was iteratively adjusted to a constraint of 92% of the maximum had the best match in peak demand compared with the recorded electricity demand (SSEN, 2021). This adjustment to the model is not uncommon in energy modelling when there is a need to reconcile simulation outputs with observed or known system behaviours. However, it's crucial to document such adjustments to ensure that they are justified and accurately reflect the intended improvements in the model's accuracy.

4.2.5 Lighting calculations in EnergyPlus (EP)

Lighting demand was calculated in SimStock by converting time use profiles into occupancy profiles for each property based on whether the individual was asleep or not. The SimStock framework was used to automate EP with the "Daylighting Controls" object used assess the illumination levels within a property and adjust lighting accordingly when occupants were present and awake. "Daylighting: Reference Point" objects were evenly placed at intervals throughout the property to calculate illumination levels for specific areas, reducing the need to calculate lighting demand for the entire floor area. The W/m^2 values were assigned to ensure that the annualised lighting demand matched recorded values for both domestic (Intertek, 2012) and commercial (BEIS, 2016a) properties.

4.2.6 Weather characteristics

Weather data was included with the Oikolab weather API service (Oikolab, 2021), based on reanalysis data from the European Centre for Medium-Range Weather Forecasts. Weather data for specific locations and time ranges was processed to create the weather file used by EP (Yang, 2021) - variables used are given in Table 4-4. The temperature data was also used for the seasonality of domestic and non-domestic categories (Section 4.1.6). For the demand model validation (Section 4.5), data for the same period of the recorded GSP data was used (April 2016-17). For the final demand scenarios of the model (Section 4.6), time periods described in Section 3.4.5 were used.

Table 4-4: Weather variables extracted using OikoLab and used to create SimStock EPW weather files.

Temperature (°C)	Dewpoint temperature (°C)	Surface solar radiation (Wh/m2)
Surface thermal radiation (Wh/m2)	Surface pressure (Pa)	Surface diffuse solar radiation (Wh/m2)
Relative humidity (%)	Wind speed (m/s)	Surface direct solar radiation (Wh/m2)
	Total cloud cover (%)	

4.3 Treatment of demand unlikely to be electrified

It has been assumed that all non-electrified demand will be met by hydrogen (or a similar hydrogen-based fuel), less the biogas energy potential for distilleries only (see Section 5.6). Projecting forward to net zero, there is still significant uncertainty in which specific fuel might be most suitable or economical where electricity is not viable - for example use of ammonia for heavy shipping (National Grid, 2023). Unabated fossil fuel use is incompatible with the definition of net zero assumed in this thesis (Section 1.3) and the currently prohibitive cost of direct air capture of CO_2, so both are not considered.

As one of the main objectives of the Net Zero model being to consider balances of technologies across the whole energy system, a key consideration will be the interface between energy types and their characteristics (i.e. electricity vs. hydrogen; on-demand vs. storable). In this context, differences between hydrogen and ammonia are less important and for simplicity are not considered. Perhaps the single most important aspect of non-electrical, low carbon energy types (including biogas) is the ability to store energy for periods of low renewable generation, an issue which has yet to be demonstrated at scale without fossil fuels. This is considered in the final Net Zero model (Section 7), but these demands could not be validated as per the electrical model due to lack of other datasets to compare with.

Demand sectors of freight, agriculture, ferries, and distilleries were modelled separately with distinct datasets for the entirely island local authorities (Orkney, Shetland, and Na h-Eileanan Siar). These were then used to develop metrics based on other factors which could be extrapolated to the remaining local authorities shared with the mainland (North Ayrshire, Argyll and Bute, and Highland).

4.3.1 Freight and agriculture demand

For freight and agriculture, annual local authority demand was available for fossil fuels (BEIS, 2022g). To convert these to nodal demand, two metrics were used. For freight, it was the total non-domestic floor area from the buildings database, assumed to be representative of the freight demand for that region. For farms, it was the number of farms in each region. For the local authorities where the annual demand solely for the islands was known, factors per farm or floor area were calculated and then assigned to the other local authorities by the number of farms or commercial floor area. The demand was then assigned to the nearest petrol station from the buildings database.

4.3.2 Ferry demand

Demand for ferries was available via FOI requests from the main ferry companies: Caledonian MacBrayne (Scottish Parliament, 2019b), Shetland council (Shetland Islands Council, 2023), and Orkney council (Orkney Islands Council, 2023b). Island routes were also manually collected (Figure 4-10), with only those connecting islands modelled (shown in green) - it was assumed that ferries from the mainland (shown in red) would refuel there.

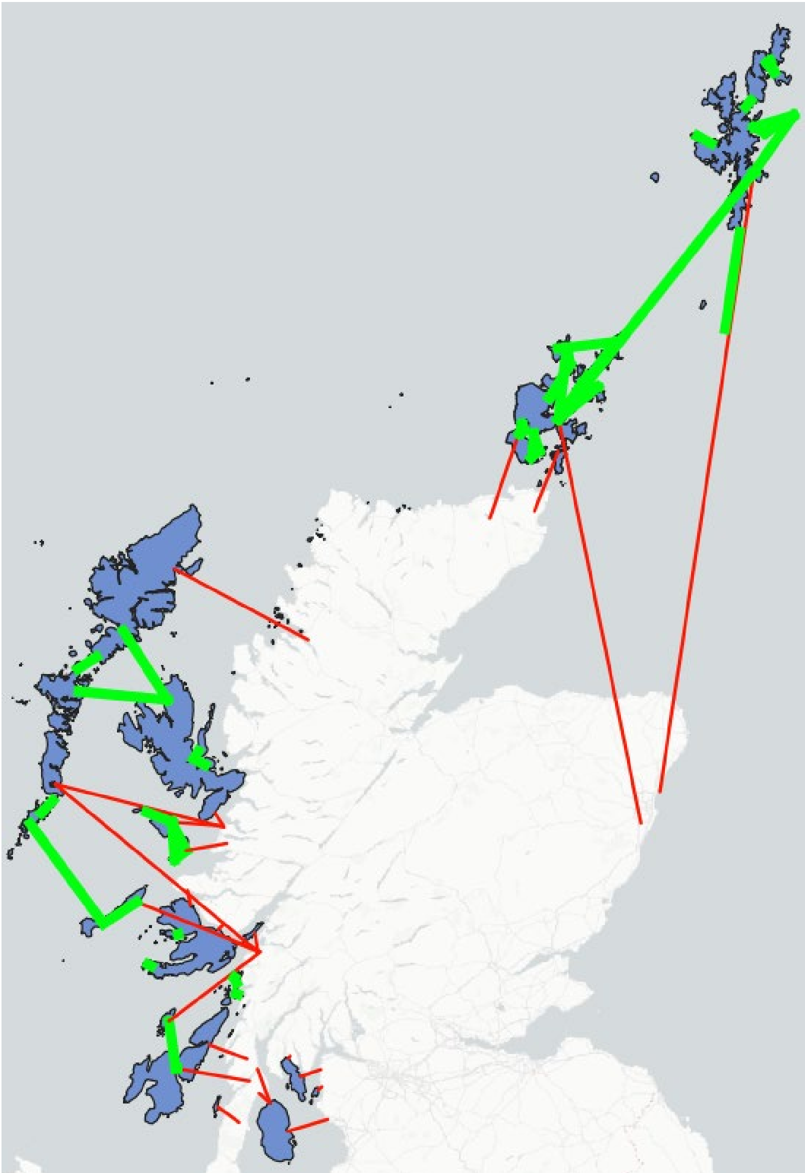

Figure 4-10: Modelled ferry routes indicated in green, with excluded mainland routes shown in red.

As ferry demand was only provided per vessel, not ferry route, to approximate ferry demand for each route and adjacent node, demand was appropriated based on ferry passenger numbers used for tourist demand (Section 4.1.5). The annual fuel demand per region was then apportioned to each island ferry route based on annual passengers.

4.3.3 Distilleries heat demand

Electrical demand in distilleries currently makes up 16% of the total, with the remainder being heat met on the islands largely by fuel oil (Ricardo Energy and Environment, 2020). Calculation of the heat demand used this factor and the electrical demand (Section 4.1.3). This heat demand will either be met by biogas or hydrogen depending on the scenario in the final model - Section 7.

4.3.4 Modelled total non-electrified demand

The total demand of this section is shown in Figure 4-11. As discussed, this demand is based on historic demand - as the market for hydrogen is not yet developed, there is no data against which the results can be validated other than the datasets used to create it (unlike the electricity model, which is validated in Section 4.5). Implications of the clustering of hydrogen demand will be discussed in the conclusions (Chapter 8).

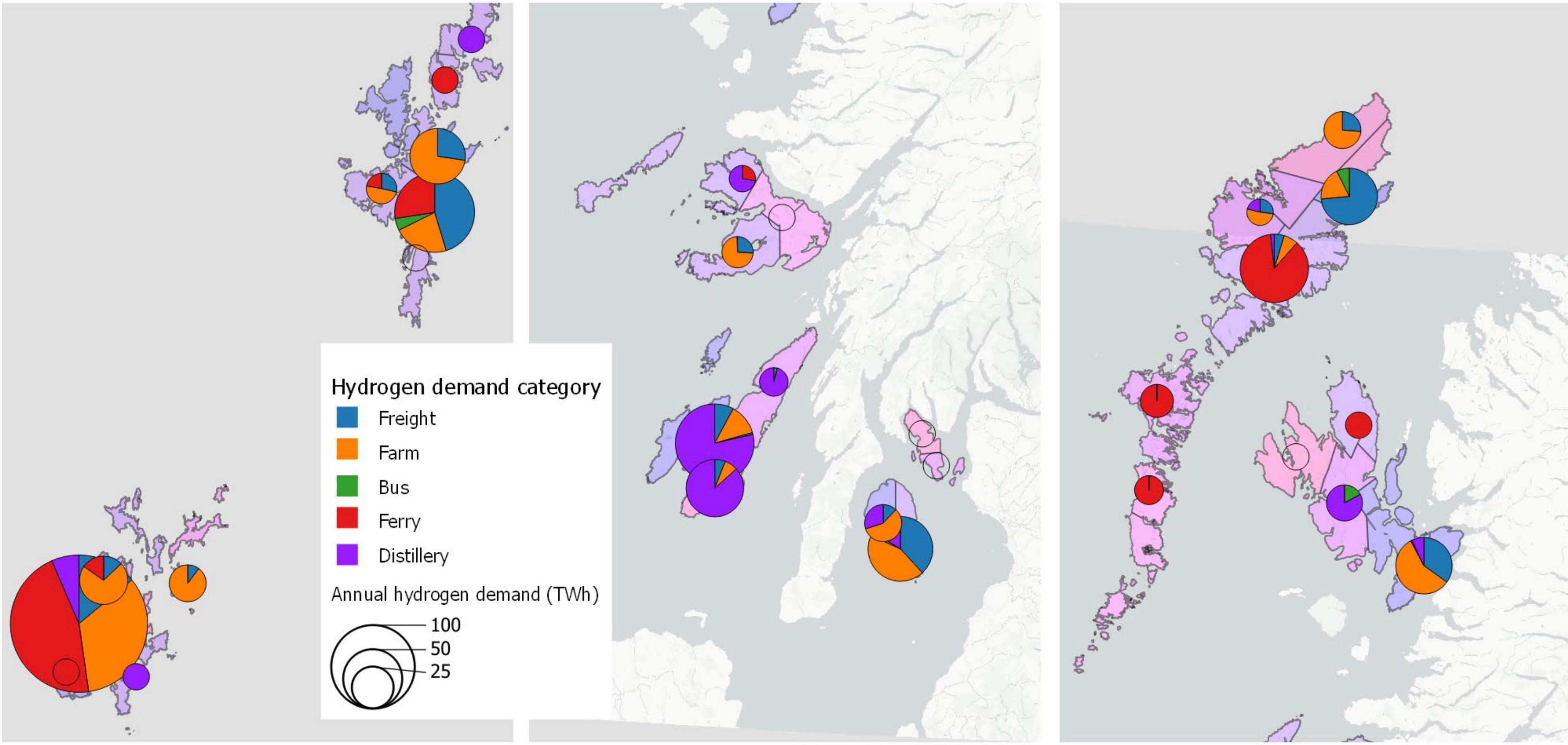

Figure 4-11: Categories of modelled hydrogen demand by local authority (left to right): Shetland & Orkney; Argyll and Bute & North Ayrshire; Highland & Na h-Eileanan Siar.

4.4 Simplified representation of mainland demand

Separately to modelling of island demand, the Net Zero model must consider mainland UK demand. However, modelling at the same level of detail would not be possible. A simplified HDD representation based on National Grid's FES was developed. With national demand data (Elexon, 2019) and HDD data (DESNZ, 2023e), a relationship was derived (Figure 4-12), showing how UK demand fluctuates by HDDs. This allows demand to be approximated with HDDs for the final model weather periods (Section 6.4.2). Although this relationship will likely differ significantly by 2045 due to electrification of demand (Kennard *et al.*, 2022), this simplification capture the level of detail required to model the impact of mainland demand for the islands.

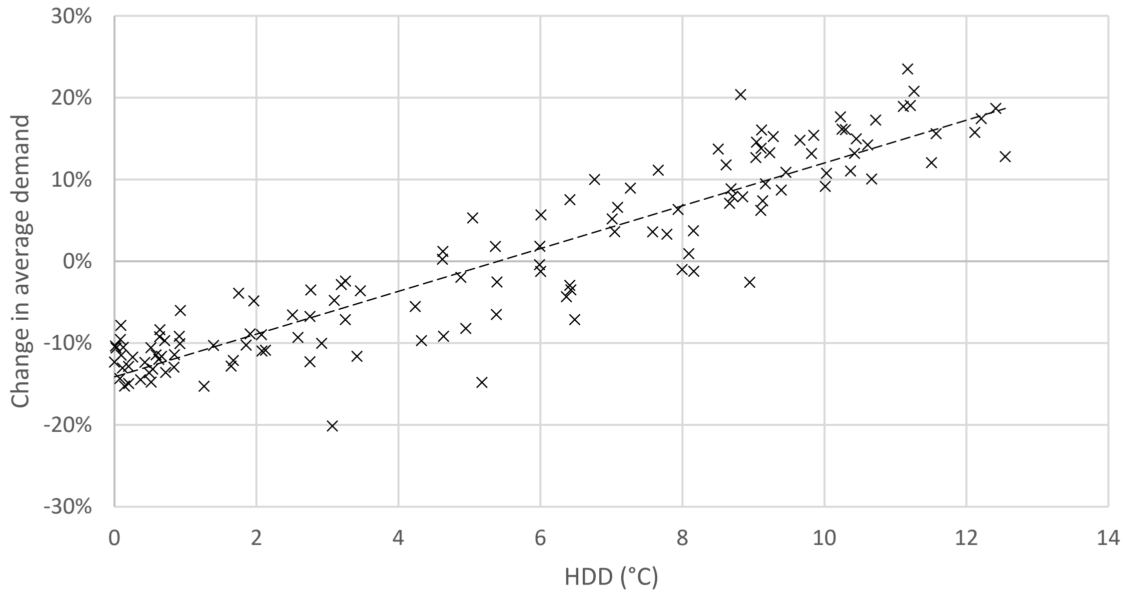

Figure 4-12: UK national demand compared with HDD.

To convert this relationship into an hourly demand profile (Figure 4-13), peak demand from the FES was used as an upper limit (National Grid, 2023). An average daily profile was assumed from a work estimating daily demand for 2050 (Bobmann and Staffell, 2015). Weather data for the specific weather periods was used for the whole UK, extracted for each DNO region (Oikolab, 2021) and weighted by population so the temperature was representative of heating demand. The model thereby captures the effect of heating on electricity demand. For the islands, this will increase electricity prices at periods of low generation and high (heating) demand as per the modelled extreme weather periods. It also captures the most important aspect of the mainland generation for modelling the islands - the balance of renewable generation versus demand which dictates island interconnection flow directions.

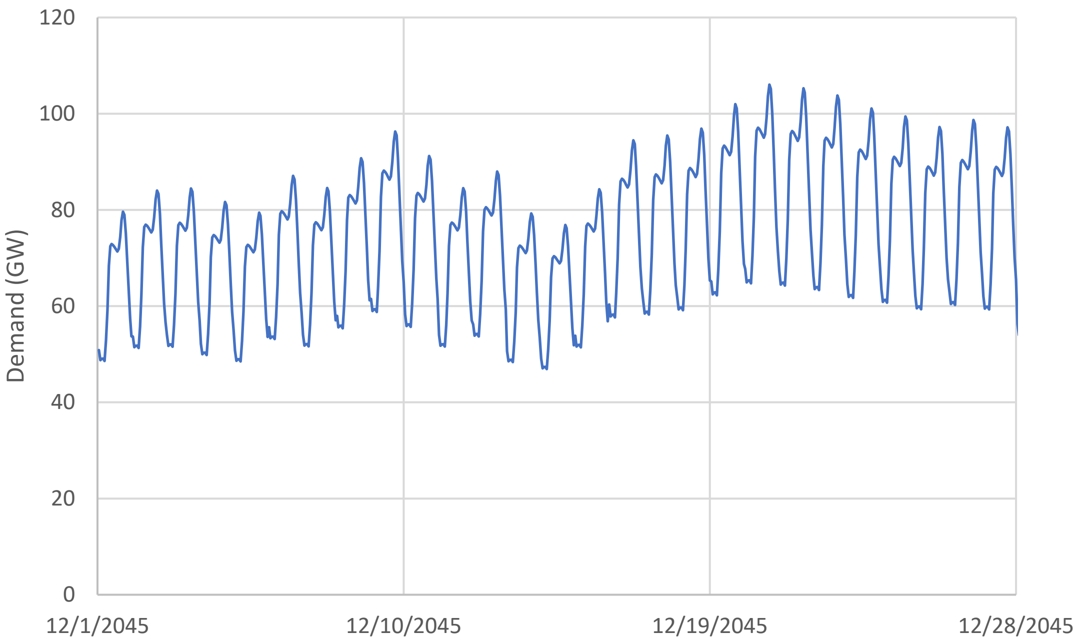

Figure 4-13: Modelled UK demand for the winter weather period.

As discussed in Section 3.4.2, hydrogen demand for the mainland is not required in the Net Zero model. The Shortage and Market Price settings in PLEXOS ensure that electrolysis operates whenever there is otherwise curtailed wind capacity, so from the perspective of the islands, whether the mainland demand is met is irrelevant.

4.5 Model validation with recorded electricity demand

The model was validated with various datasets, but primarily this was hourly GSP electricity demand for the islands for 2016 (SSEN, 2021). The residential, commercial, and industrial sector electricity demand models were aggregated across various temporal and spatial dimensions. Model data for Na h-Eileanan Siar area (21% of the total) was excluded from the calibration process to allow for separate validation of the model's performance in this region.

4.5.1 Hourly to monthly demand

Hourly, daily, weekly, and monthly basis, were compared with GSP data (Figure 4-14). At the hourly resolution, the model exhibited a mean absolute percentage error (MAPE) of 6.4%. This reduces to 1.6% at a monthly resolution, showing that the model captures the seasonal fluctuations in electric heating demand. The largest step improvement in the R2 score - from 0.87 at the hourly level to 0.94 at the daily level - indicates that the main room for improvement lies with hourly predictions. The factors affecting demand are more stochastic, which tends to average out at the daily level. It could be that behaviour patterns are affected by weather other than temperature. Comparing model errors with other weather data (rainfall, cloud cover, irradiance, wind speed - EP only uses irradiance in heating calculations) did not highlight any significant correlation. Further work would be needed to address the intraday inaccuracy.

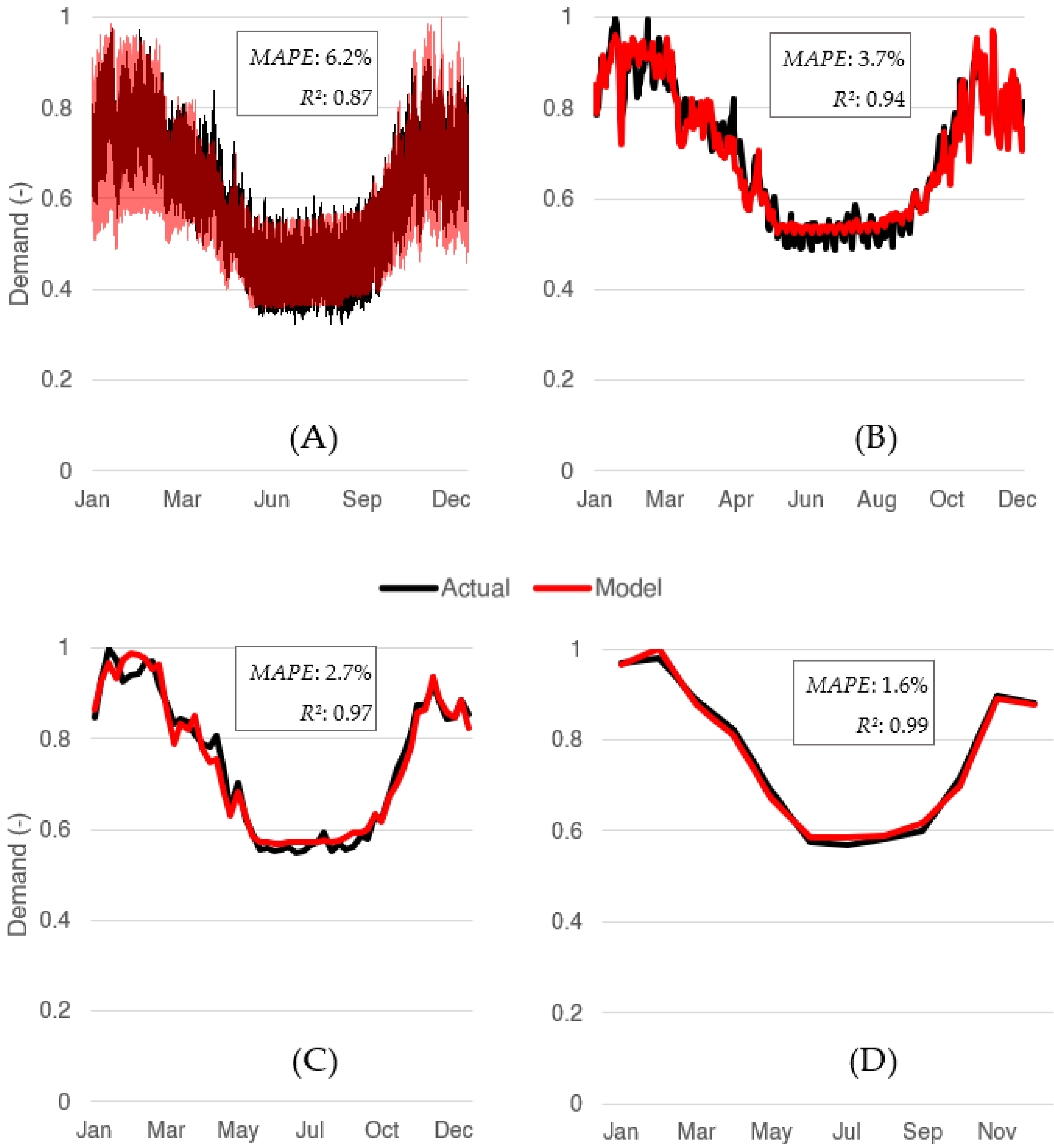

Figure 4-14: Averaged hourly (A), daily (B), weekly (C) and monthly (D) average modelled and actual (SSEN, 2021) *electricity demand* (Matthew and Spataru, 2023a).

The average daily demand categorised by type (Figure 4-15), demonstrates the model's depiction of average daily fluctuations with a MAPE of 2.5%. The most noticeable deviation is overnight, when electric storage heaters are at their peak, identified as a gap in the data. The timing of the dual morning and evening demand peaks is also slightly misaligned. This could be affected by the islands' more northern latitudes, with correspondingly different daylight hours compared to the largely English time use data.

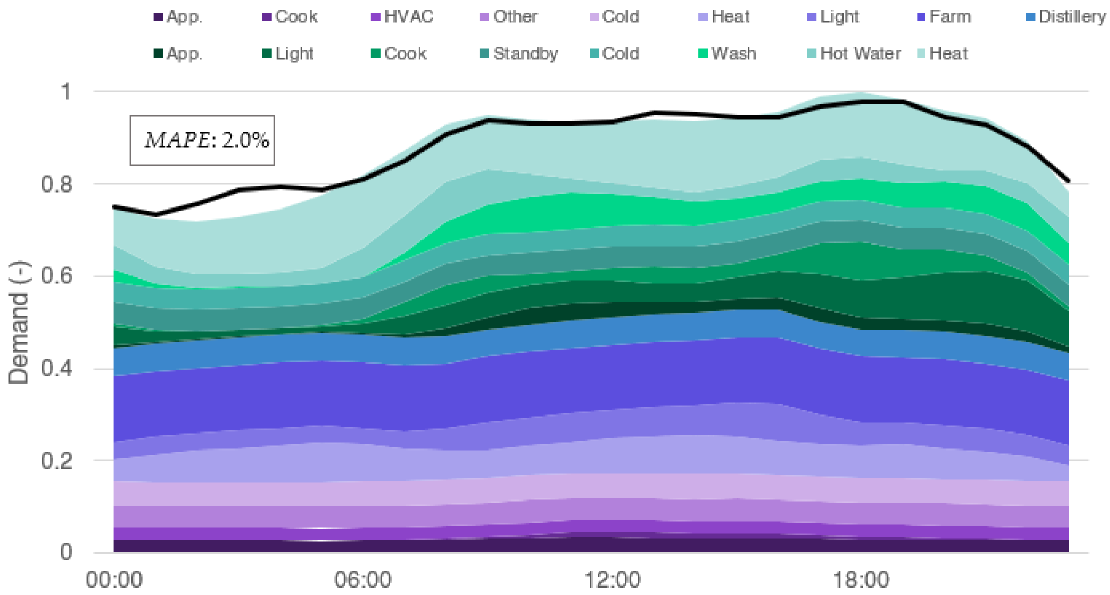

Figure 4-15: Average day of electricity demand by category with actual demand in black (Matthew and Spataru, 2023a). *Commercial and industrial demand is shown in blue/purple; domestic is shown in green.*

4.5.2 Seasonal demand

Looking at the seasonal average hourly demand (Figure 4-16), the model is most accurate in the summer. There is however a discrepancy at 23:00 due to lighting. To prevent EP from calculating lighting demand for the entire floor area (i.e., the highest zonal resolution available without detailed room layouts), the distribution of lighting across the property was evenly allocated as daylighting reference points (Section 4.2.5). This approach aimed to improve the representation of lighting and better align with the surveyed household appliance demand. However, for larger properties with more than ten occupants (the maximum number of lighting controls points allowed in EP), the model would overestimate lighting demand by illuminating larger areas of the property than necessary. Again, in the winter, the largest discrepancy is overnight, most likely due to the unavailability of storage heater demand profiles.

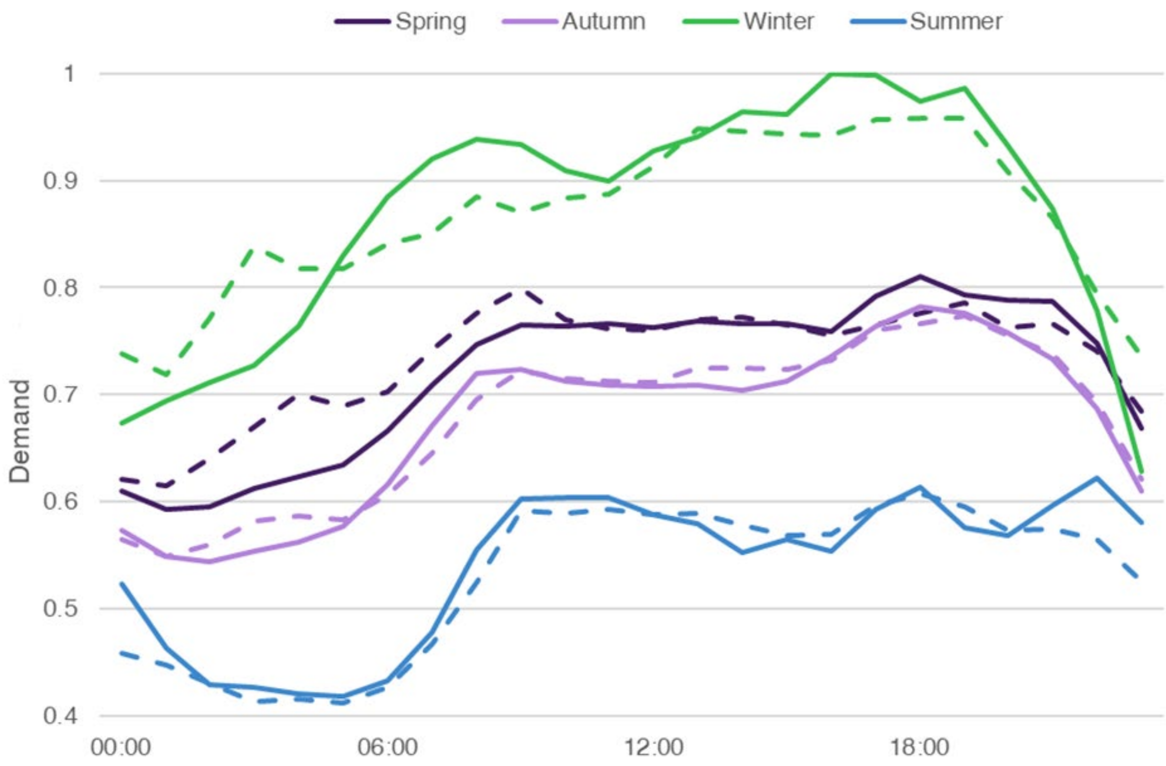

Figure 4-16: Average day of modelled (full line) and recorded (dashed line) demand by season (Matthew and Spataru, 2023a).

4.5.3 Local authority demand

At the local authority level at a weekly resolution (Figure 4-17), the model captures the total annual demand with a MAPE of 8-20%. Na h-Eileanan Siar (excluded from calibration) has the smallest percentage error, indicating that the model accounts for the factors influencing local electricity demand. Aggregating results for all the islands, errors in datasets tend to balance out, but this accuracy clearly decreases with smaller geographic areas. The completeness and accuracy of the building datasets is uncertain - in Section 4.2.1, 5% of buildings area was manually excluded due to misclassification, the influence of which on electricity demand is not clear but likely notable (Section 2.2.2).

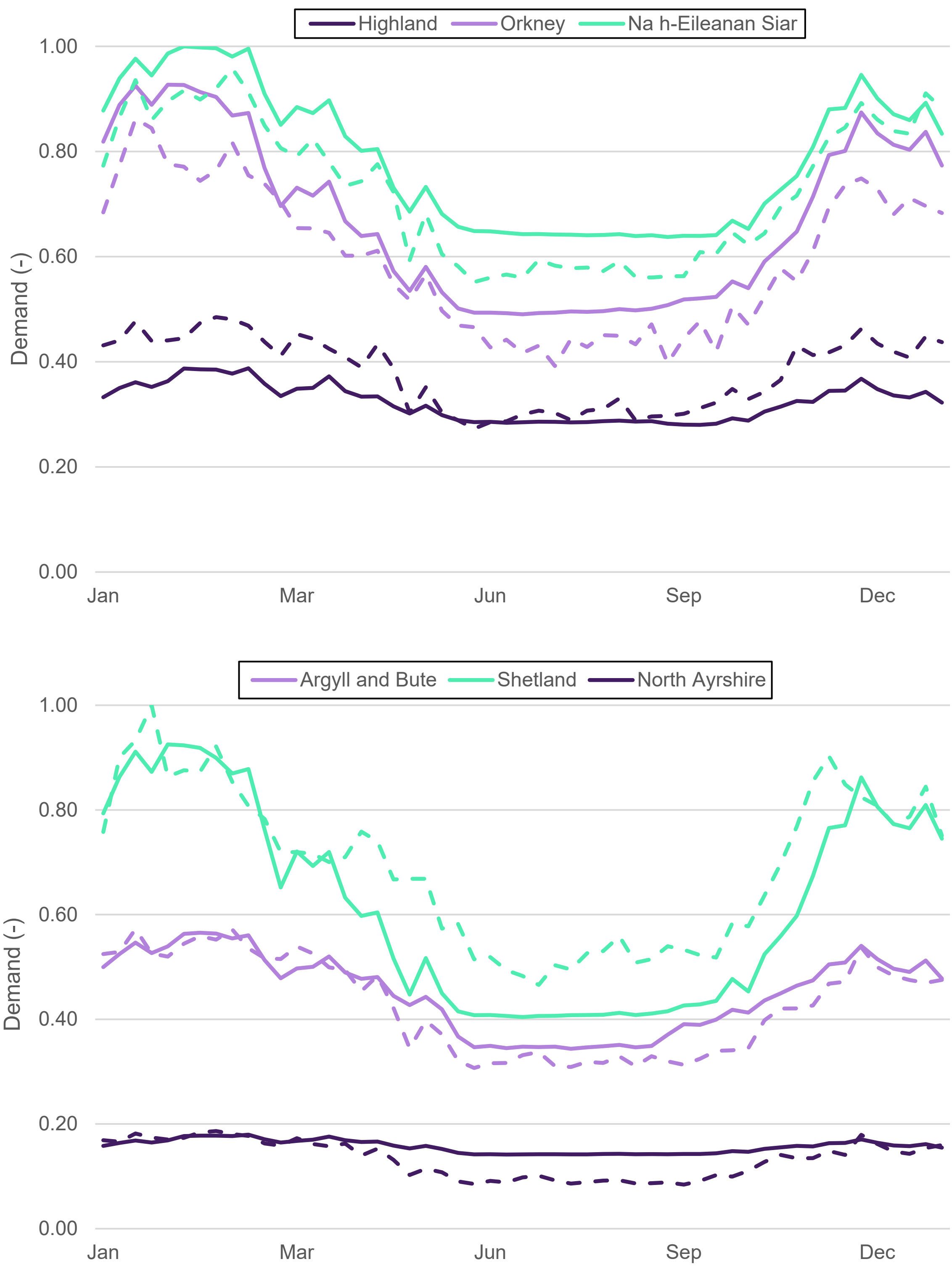

Figure 4-17: Weekly averaged demand aggregated by local authority, where the dashed line is actual demand and the solid line is modelled (Matthew and Spataru, 2023a).

The influence of the tourism modelling is clearer for local authority level demand, as excluding it increased the error for all local authorities. It could however be improved with better data. Geographically specific tourism data only existed for three entirely island local authorities (Na h-Eileanan Siar, Orkney, and Shetland), where tourism is a smaller proportion of the local population. In other areas, where tourism has a larger role due to being more accessible from the mainland, numbers were approximated but would likely have distinct visitor profiles. This especially evident for North Ayrshire (Figure 4-17), which has the smallest full-time population and is closest to mainland population centres. In the summer, the tourism model predicted daily tourism figures peaking at 2.7 times the local population. Over this peak tourist season, demand is overestimated by approximately 50%, but this declines with visitor numbers in the winter. More specific seasonal visitor data would improve the model compared to the high-level surveys used.

4.5.4 Grid supply point demand

Annual GSP level (the most geographically specific available) errors show that while the model captures the regional variability of demand, errors tend to average out (Figure 4-18). The precise GSP areas (i.e. the GSP each property corresponded to) was not available from the DNO, therefore this had to be approximated by proximity to the nearest distribution building location in the network shapefiles (SSEN, 2019). The accuracy of this is not clear but could explain a large part of the error in Figure 4-18 which averages out.

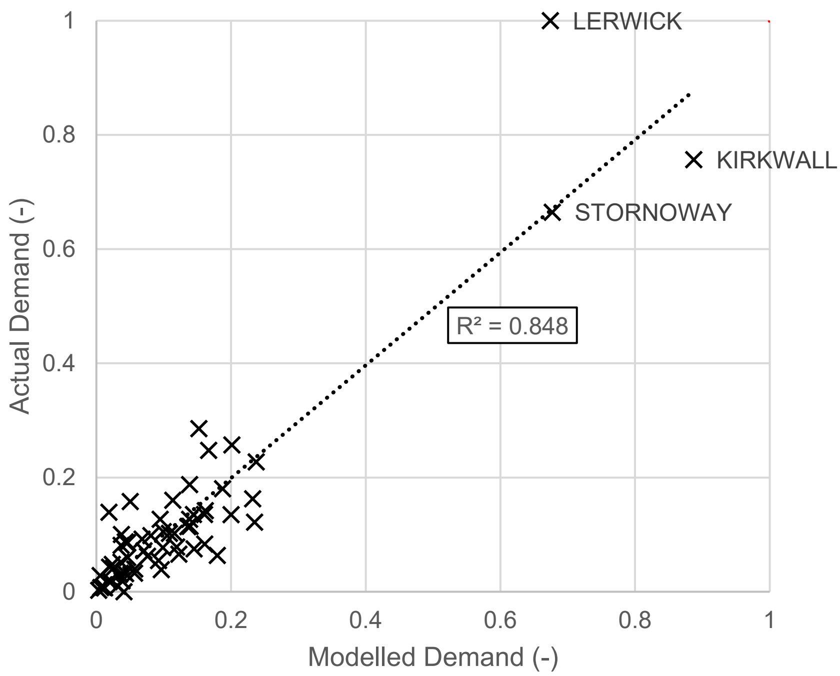

Figure 4-18: Comparison of modelled and actual annual GSP demand (Matthew and Spataru, 2023a).

For the two largest areas (excluding Lerwick), the model error is ±12%. On Lerwick there is an energy-from-waste power plant which heats local properties. Coverage data had to be approximated due to data privacy issues. Error in this estimation, particularly for large commercial buildings, likely explains this more significant discrepancy.

Households have also been randomly assigned to building polygons, which could have a greater effect for the smallest GSPs. The remoteness of buildings could be correlated with the likelihood of occupancy (remote islands being more likely to depopulate), in which case the model would tend to overpredict demand. Identifying other factors would require a higher resolution of demand data.

4.5.5 Model limitations and improvements

Results show that the model captures factors influencing electricity and heating demand. Errors identified can in most cases be linked with inconsistent data used to build the model. A significant issue arises from the disparity in years across datasets. The validation year of 2016 was selected as a midpoint between the available population census data (2011 - the 2021 updated being delayed by COVID) and business demographic data (2021). Demographics are a major factor affecting demand which could have changed significantly in the intervening 5 years.

Geographic specificity of data could also be improved. Unavailable building constructions for commercial EPCs had to be approximated for attributes such as heating setpoints, heating profiles, HVAC operation, and glazing ratios. Commercial data availability could be improved in future works - which the use of time use data addressed here for occupancy profiles. More specific tourism data could also improve accuracy for regions where this demand is proportionally greater. If the accuracy of the GSP areas could be improved, model discrepancies would be identifiable.

Data was also missing or unusable from several datasets, and correlations between some datasets are approximated:

(i) 3.5% of the validation demand data was corrupted.

(ii) Mislabelling of agricultural buildings as domestic required manual correction, but only for largest buildings (Section 4.2.1).

(iii) Unknown seasonality of heating demand related to identical heating setpoint temperatures (Section 4.2.4).

(iv) Unavailability of industrial demand seasonality, particularly whisky (Section 4.1.3).

(v) Heating demand profiles for electric storage heaters also had to be approximated (Section 4.2.3) - for model projections this will be less significant though if replaced with heat pumps (Section 4.6.3).

(vi) Building constructions were assigned by size and type using combinatorial optimisation (Section 4.2.2), which could neglect other building type (e.g. height or age) correlations.

(vii) The statistical representativeness of the EPC dataset (only buildings sold in the last 10 years or voluntarily had a survey) is unclear, but there were significant discrepancies between this and the SHCS data. EPC data has been shown to have notable errors (Hardy and Glew, 2019).

(viii) Random assignment of heating profiles to households (Section 4.2.3) does not capture demographic influences - inclusion of household EPC rating in time use data would enhance this.

(ix) EP heating and lighting demand only uses temperature, wind, and irradiance (Section 4.2.6) - its unclear if other aspects (e.g. rain) could influence demand or behaviour (e.g. time spent at home/outside/etc.).

Addressing these aspects, particularly for non-domestic sectors, would improve the model. As stated, the approximation from domestic data to non-domestic is only acceptable due to the island being relatively rural - if the model were used anywhere more urban, results would likely differ. Improved and publicly available data is needed for non-domestic building stock if whole-system demand models are to be improved or more widely used.

4.6 Net Zero demand model scenarios and policies to achieve them

Scenarios have been modelled with specific policies for appliances, buildings, heating, transport and industry, to highlight how policy could influence energy demand. Three scenarios for the different whole model scenarios (Section 3.5- scenarios are indicated as follows) are modelled varying by rates of policy implementation that would result in high (BAU/ Export net zero scenarios), medium (Middle scenario) and low (Independence scenario) final demand. The rationale behind the two extremes of the BAU/ Export and Independence scenarios are described below - the Middle scenario is the average of the two. Specific policies are discussed in the following sections. Their targets/ achievement rates are given in Table 4-5, where the numerical values for each model scenario rate of change are based on the specific policies depending on how the efficiency outcome compares with the below scenario description.

BAU/ Export scenario - government policies are described and historic achievement rates (not the stated targets) used to project forward to 2045. This includes: no change to average appliance efficiency; minimum EPC ratings for new and renovated properties of band D (average EPC of C/D by 2045); current renovation and heat pump uptake rates (58% with heat pumps by 2045); and no changes in efficiency for private vehicles, public transport or industry. This results in the highest modelled demand for the islands.

Independence scenario - an improved ambition for energy efficiency with a higher (but not upper) reduction of demand. Rates either ensure that existing targets are met (such as 100% heat pump uptake or minimum EPC standards) or at a higher bound of feasible limits (such as EV efficiency). These include average appliance efficiency rating of A; renovations to a minimum EPC rating of B (the Scottish government target for the social rented sector by 2032); 100% heat pump uptake; greater private vehicle efficiency and investment in local buses; and industrial efficiency in line with industry specific net zero projections. This results in the lowest modelled demand of the three scenarios.

Table 4-5: Summary of the modelled demand-side energy policies and the inputs used in the model for each scenario (Matthew, 2024b).

Category	*Aspect*	*Description*	*Model input*	*Scenario metrics*			*Policy used to design scenario metrics*
				BAU/ Export	*Middle*	*Indpen-dence*	
Appliances	Appliance efficiency	More efficient appliances are encouraged through raising ratings standards	Average appliance energy efficiency rating improves from D to:	No change	C	A	Appliance eco-design regulations (UK Parliament, 2021)
	Standby power	Minimum standby power per appliance is decreased	Average standby appliance demand (W):	7.7	5.5	3.5	Appliance eco-design regulations (UK Parliament, 2021)
Flexibility	DSR	DSR availability for heating, private transport, and hot water	Household DSR participation rate:	0%	25%	50%	Demand flexibility service (National Grid, 2023)
Building fabric	New build	New buildings added to minimum EPC rating with heat pumps	New build rate of 1.2% p.a.; minimum EPC rated:	D	C	B	Building standards (DESNZ, 2023i)
	Building retrofitting	Buildings retrofitted to the above minimum rating - within limits of survey	Rate of annual building retrofit (%):	1%	2.2%	3.4%	Minimum EPC targets (Scottish Government, 2022a)
Heating technology	Heating electrification	Upgrading to heat pumps assumed to occur under support schemes, remainder get direct electric heaters.	Annual heat pump uptake rate:	1%	1.8%	2.5%	RHI (BEIS, 2022e); Boiler upgrade scheme (DESNZ, 2023b)
Transport	Private transport demand	All vehicles electric by 2045, improved energy efficiency for vehicles through speed limits or SUV taxes.	Average vehicle efficiencies (kWh/km):	0.3	0.23	0.15	Internal combustion engine ban (UK Government, 2020)
	Public transport demand	Increased expenditure for local bus networks	Increased number of bus routes by factor of:	1	1.5	2	Internal combustion engine ban (UK Government, 2020)
Industry	Industrial demand efficiency improvements	Annual efficiency improvements for distilling and farming.	Annual energy efficiency change (%):	0%	-1%	-2%	Climate change agreements (DESNZ, 2023i)

These assumptions about the changes in demand through to 2045 account for changes in technology only. By using time use survey data (and other recorded data such as domestic heating setpoint temperatures), the model assumes the same behaviours and lifestyles as today for 2045. The potential effects of aspects such as the rebound effect are discussed in the context of the overall model in Section 7.4.1.

4.6.1 Appliance demand model inputs

To simulate appliance eco-design regulations, changes to energy ratings were used. A revision of the rating systems would lead to an increase in the average appliance efficiency category (Table 4-5) relative to the existing ratings (BEIS, 2021b). The factors of improvement provided in Appendix B.2 were used to adjust appliance demand for each appliance category. Differences in costs for standard household appliances were manually collected and assigned as described in Appendix B.2. Standby power was adjusted by assuming enhancements in the regulations governing the maximum standby power demand, with the modelled demand per appliance adjusted to align with the values in Table 4-5.

The main policy relating to appliances is the Appliance Ecodesign regulations. In line with European and international regulations, the steady increase in efficiency standards should be a key part of net zero plans. The UK could pursue more ambitious energy ratings though, as research has shown the overall lifecycle costs of more efficient appliances can be cheaper than less efficient alternatives (IEA, 2024).

4.6.2 Building fabric demand model inputs

Building retrofits were simulated using EPC survey enhancements (Scottish Government, 2021b). These specify measures such as wall or roof insulation; draught-proofing; double or triple glazing; heating technologies; wind or solar PV; and efficient lighting; as well as property-specific costs and changes to EPC rating. Modelled building improvements were limited to those surveyed, ensuring the scenarios are achievable within existing building stock constraints. The rate of retrofit (Table 4-5) was assumed from historical rates by local authority (Scottish Government, 2023b). Costs data for upgrades was also used from the EPC database in the range of high-low costs detailed (also used for other cost categories).

New constructions were added at historical construction rates in each local authority area, (Scottish Government, 2023b). EPC database constructions were sampled such that the minimum rating of new buildings matched targets in Table 4-5. All new builds were assumed to include heat pumps. The difference in costs between new build EPC ratings was assumed to be the same as retrofitting improvements, which is likely an over-estimate.

The main policy that would target this aspect is expected in 2025, the Future Homes Standard. To what extent it will reduce emissions of new houses is not yet clear (UK Government, 2021). To achieve the more ambitious demand scenario (Independent scenario), the Government would need to set more ambitious targets for building fabric and low-carbon or zero-emission heating technologies and ensure that likely more expensive retrofitting is not needed in the future. For existing buildings the ECO, Home Upgrade Grant, Local Authority Delivery, and Warm Homes provide support in theory for the fuel-poor, but recent performance has been insufficient (CCC, 2023) and would result in the higher demand scenario of the BAU/Export scenarios. Rolling them out at greater scale would benefit both recipient households and the whole electricity system. Support can also still be targeted at worse-off households to address barriers of erratic funding support, regulation, and access to finance (CCC, 2023).

4.6.3 Heating technology demand model inputs

The BAU/ Export demand scenario reflects historic rates of heat pump adoption, resulting in 58% of properties having heat pumps by 2045 (DESNZ, 2023b). The Independence scenario is based on the annual installation rate needed to for 100% heat pump coverage by 2045 (the Middle being the average). Costs for direct electric heating were used from the EPC database (Scottish Government, 2021b) and heat pump costs were assigned by the required heat pump capacity per property floor area (Kokoni and Leach, 2021).

To achieve greater heat pump uptake, the recent increase to the grant available for domestic heat pumps by 50% (DESNZ, 2023f) is commendable, but whether it can help meet the target of 600,000 annual installations by 2028 is uncertain. Supporting their roll-out would need to be combined with supporting them for new homes (Section 4.6.2). Support will also likely be needed to help train installers of heat pumps to reach near 100% heat pump deployment (UKERC, 2023).

4.6.4 Transport demand model inputs

Domestic and public transport changes have been included. Transport efficiency changes in industry are assumed to come under the industrial model in the following section. For domestic EVs (assumed to be the main mode of transport for all scenarios), vehicle efficiency (kWh/km) used to calculate the charging demand profiles was adjusted (IEA, 2023). Public transport is the only aspect modelled where the demand is assumed to increase from the Independence to BAU/ Export scenarios, accounted for by the assumed bus route expansion factor in Table 4-5.

For all scenarios, continued support for the decarbonisation of transport would be needed, through supporting EVs. Achieving an improved vehicle efficiency would require either penalising less efficient vehicles or supporting more efficient ones. Less efficient EVs could result in higher electricity system costs for everyone, so taxation for less efficient cars could help encourage greater efficiency and reduce overall costs. This could be similar to the French system of CO_2 taxation, which has an exponential price relative to emissions (French Republic, 2024).

4.6.5 Industry demand model inputs

The model assumes an annual improvement rate for industrial electricity demand, assumed from net-zero modelling specifically for the Scottish whisky industry (Ricardo Energy and Environment, 2020). While more detailed data wasn't available for the other major industries of fish processing and farming, the model approximates the annual rates for these sectors based on the estimated distilling rates. As distilling constitutes most of the industrial demand on the islands, these approximations are considered representative for other sectors.

Industry is generally an extremely heterogeneous sector, but this can be addressed by technology neutral policies such as efficiency auctions. They can be targeted at specific industries or types of emissions, and can facilitate changes in emissions-heavy industries which have high capital costs in switching to low carbon alternatives (Patel *et al.*, 2021). Similar policies could encourage fuel switching away from fossil fuels to biogas for example.

4.7 Results of the demand model scenarios

With the electricity model validated against recorded GSP demand data (Section 4.5), it can be used for projections of demand in the 2045 net zero energy system. The differences between scenarios presented in the previous section are described. Results are presented for both modelled periods of extreme weather (Section 6.4.2), annualised values and compared with the baseline year used for the model validation (Matthew and Spataru, 2023a).

4.7.1 Changes in hourly demand

Differences in summer and winter hourly demand (Figure 4-19) illustrates how policies could affect demand. The 2016 baseline year (with 43% heating electrification) aligns with the Middle scenario. The electrification of transport, heating, and household cooking offsets building and appliance efficiency improvements. Average winter demand varies from 76-138 MW, while summer demand ranges from 56-97 MW across Independence to BAU/ Export scenarios. The majority making up seasonal differences are heating (47.7%), transport (16.2%), lighting (9.3%), and industry (9.0%) caused by temperature, but also changes in daylight hours.

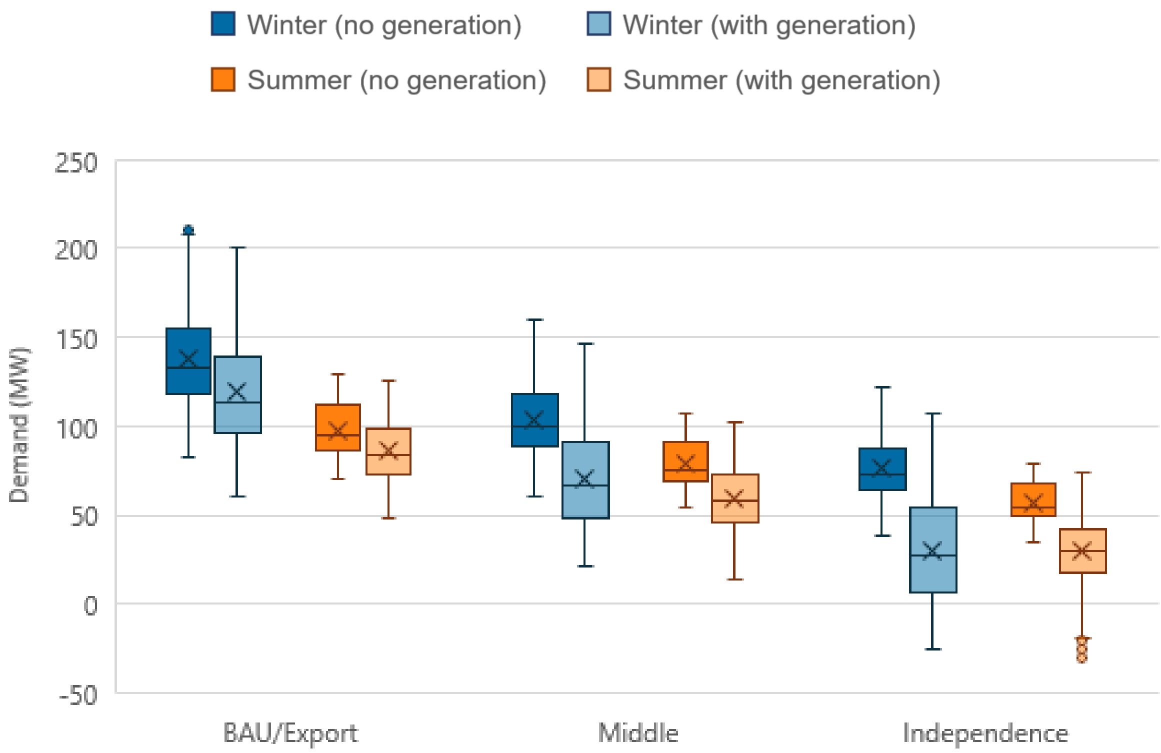

Figure 4-19: The range of summer and winter hourly demand (Matthew, 2024b).

The flexibility required in an energy system can be gauged by the ratio between the maximum and minimum demand. This ranges from 2.8 to 3.1, with the current value for the entire UK being 3.1 (DESNZ, 2023d; National Grid, 2023). This is expected given the consistency of factors and sectors influencing both maximum and minimum demand across scenarios. Contrasting with the baseline year's peak demand of 133 MW, the BAU/ Export scenario increases by 47%, while the Independence scenario decreases by 22%. Again, this should be compared with the greater electrification – an additional 57% of households have electric heating and 100% additional private transport demand. Energy efficiency measures could play a key role to counteract increased demand electrification, which could have overall benefits in system costs that are examined in Section 7.

4.7.2 Annual demand by demand type

Under the High scenario, the islands annual demand could go up by 20% (Table 4-6). This relatively small increase compared to the mainland (National Grid, 2023) is mainly due to the currently low efficiency of the building stock and high proportion of existing electric heating for households and businesses. Even with the electrification of transport and remaining buildings heating, annual demand in the Independence scenario decreases by nearly two-thirds.

Table 4-6: Annual demand with compared with the baseline year.

	Baseline	*BAU/ Export*	*Middle*	Independence
Annual demand (GWh)	692.8	832.6	526.7	241.0
Baseline change (%)	-	+20.2%	-24.0%	-65.2%

By sector for the Middle sceniario (Figure 4-20), the main categories are private transportation (34.3% of total), heating (22.8%), and industry (22.7%). In all Independence scenario categories demand is reduced, excepting public transport, which is increased to offset a reduced private transport demand. Purely from an energy perspective, investing in public transportation is significantly more efficient, but this does not address the behavioural changes required. The savings for washing, cooking, and appliances are modest, indicating that although appliance labelling policies can contribute to minimising energy demand, policies focused on the major sectors (right side of Figure 4-20) have greater scope.

In the Independence scenario, industry, heating, refrigeration, hot water, and lighting all have scope to decrease by more than 50% from the baseline year. An added benefit of heat pumps is reducing not only heating energy demand, but also hot water. Heating demand reductions can also happen through building stock improvements (e.g. insulation, glazing, draughtproofing, etc.) (Figure 4-21). Solely considering building improvements, improving average EPC ratings from D/E to B/C could reduce heating demand by 34%. However, with 100% heat pump deployment (Independence scenario), the reduction attributable to heat pumps alone could be up to 64%.

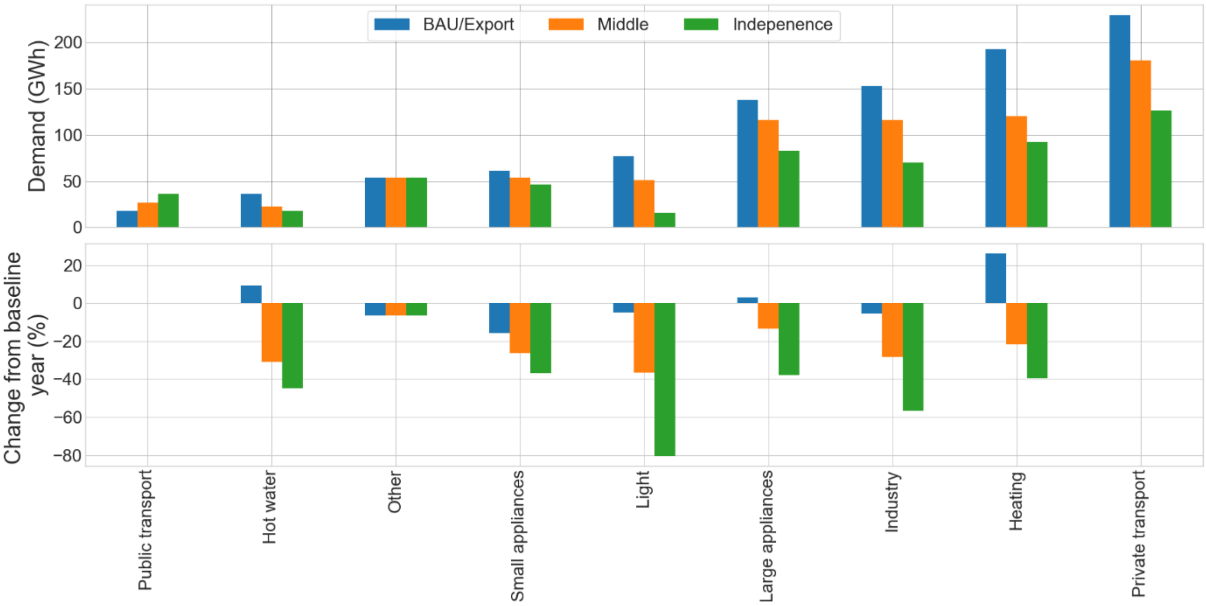

Figure 4-20: Categorical annual demand and proportional change from the baseline year. Large appliances include cooking, washing, drying, and refrigeration; small appliances are all others. Transport is excluded from the baseline year as it was not modelled (Matthew, 2024b).

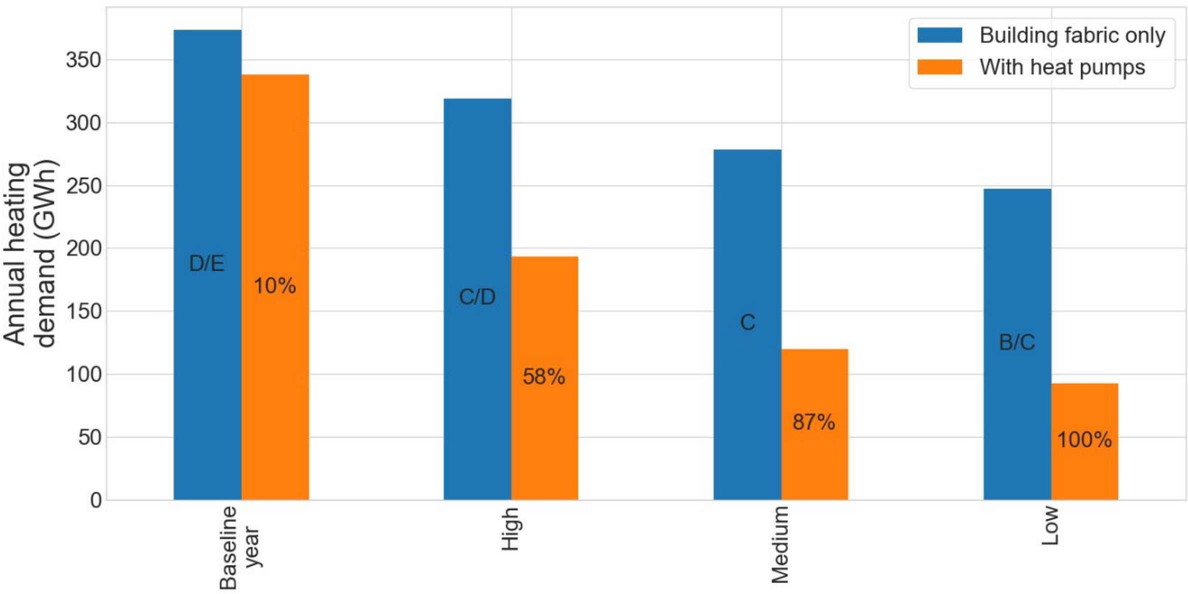

Figure 4-21: Annual heating demand compared for building fabric and heat pumps. Average EPC ratings and heat pump deployment are annotated. For the baseline year, heating demand is extrapolated from the 43% modelled up to 100% to match the scenarios (Matthew, 2024b).

4.7.3 Peak demand by demand type

Analysing the average daily peak demand (7-10:00 and 16-19:00) compared to the validation year in Section 4.5 (Figure 4-22) reveals the potential contribution of each category to average peak demand reduction. Industry demonstrates the highest potential reduction at 9.1%, followed by lighting (6.7%), and heating (5.9%), but large appliances (3.3%) and hot water (2.5%) are also notable. The marginal change in heating demand in the BAU/ Export scenario should be considered alongside the increase in heating electrification, up to 100% from 43% in the baseline year, and heat pump penetration, projected at 58.1% based on current deployment rates). While this might not represent the whole UK with currently lower heating electrification rates, it underscores the key role heat pumps and building stock measures can play in demand reduction and heating electrification. These two aspects combined results in an estimated average peak demand reduction of 2.0 kW per property (compared to electric storage heating) in the Independence scenario.

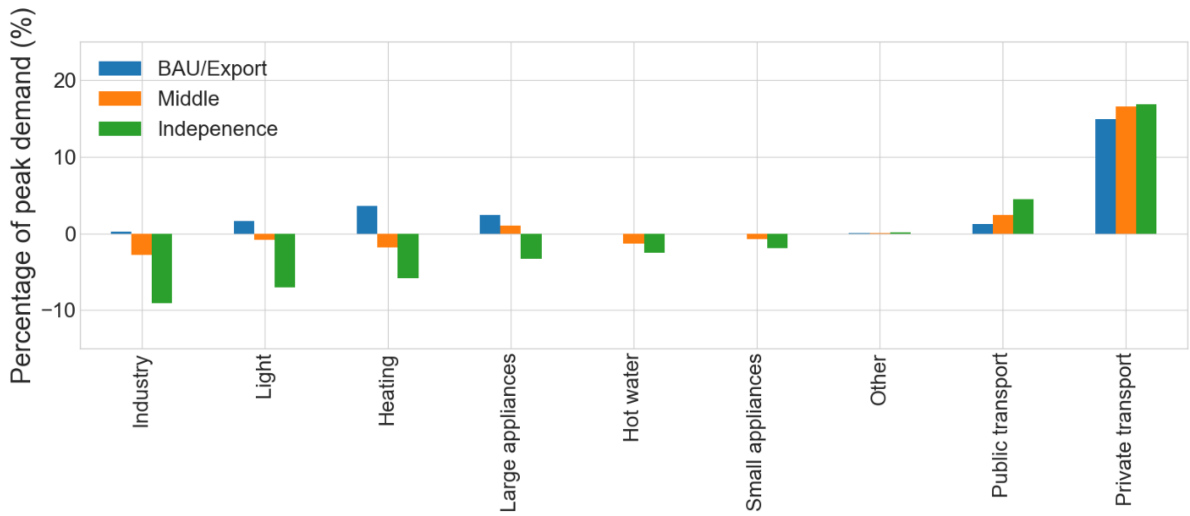

Figure 4-22: Average peak demand change (7-10:00 and 16-19:00) relative to the baseline year (Matthew, 2024b).

The difference between BAU/ Export and Independence scenarios on the coldest peak demand day highlights which sectors contribute most (Figure 4-23). While transportation has the greatest change on average days (Figure 4-22), on the coldest peak demand day, heating is the main contributor. The modelled distribution of recorded daily heat pump demand profiles (Gesche M Huebner *et al.*, 2015) will affect peak demand, but even when averaged over a 24-hour period, the most significant sector is still heating. Heating profile types will synergise with building fabric upgrades, but more work is needed to understand the correlation of building types with heating profiles. Heating profiles would also affect the potential scope for heating DSR (Section 4.7.5).

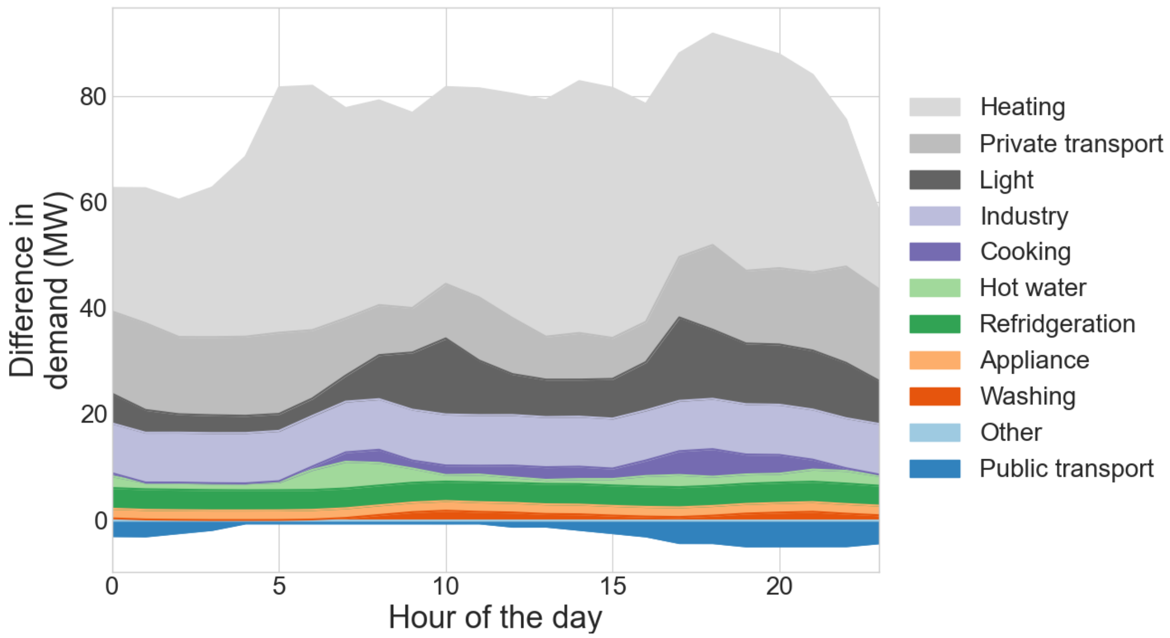

Figure 4-23: Difference between the BAU/ Export and Independence scenarios on the peak demand day (Matthew, 2024b).

4.7.4 Changes to household and business electricity bills

Examining the changes at the highest resolution (individual buildings), underscores the heterogeneity that is not evident in the higher-level results. The contrast in energy changes between the BAU/ Export and Independence scenarios per property (Figure 4-24) illustrates that efficiency potential varies massively by households and businesses. Categorizing this disparity could reveal which types of buildings are most suitable for targeted policies; there may be a correlation with the nature of businesses or building construction, but this would necessitate further analysis.

Figure 4-24: Difference between the annual energy demand in the BAU/ Export and Independence scenarios as a percentage of the BAU/ Export scenario for an urban area (Matthew, 2024b).

This can also be viewed as the changes to electricity bills from the validation year (Figure 4-25). Including savings on heating for previously non-electrically heated households and transport fuel costs (not modelled in the baseline year) would likely result in greater savings. Average bills in the Independence scenario are lower by an average of £559 for non-domestic properties, which also has fewer properties experiencing bill increases, even with demand electrification. However, even the lowest proportion of households facing bill increases (42%) is considerable. Achieving a successful transition to a net-zero energy system will necessitate fair policies that account for these effects discussed in Section 4.8 and 8.3.

Looking at the changes in electricity bills relative to heat pumps ownership (Table 4-7), the BAU/ Export and Middle scenarios differ by more than £600. Factoring the other benefits of heat pumps discussed above, the benefits are likely to outweigh the high initial cost compared to direct electric heating. The proportion of households with increased bills remains unchanged though, due to the same number of households swapping from fossil fuels to electricity.

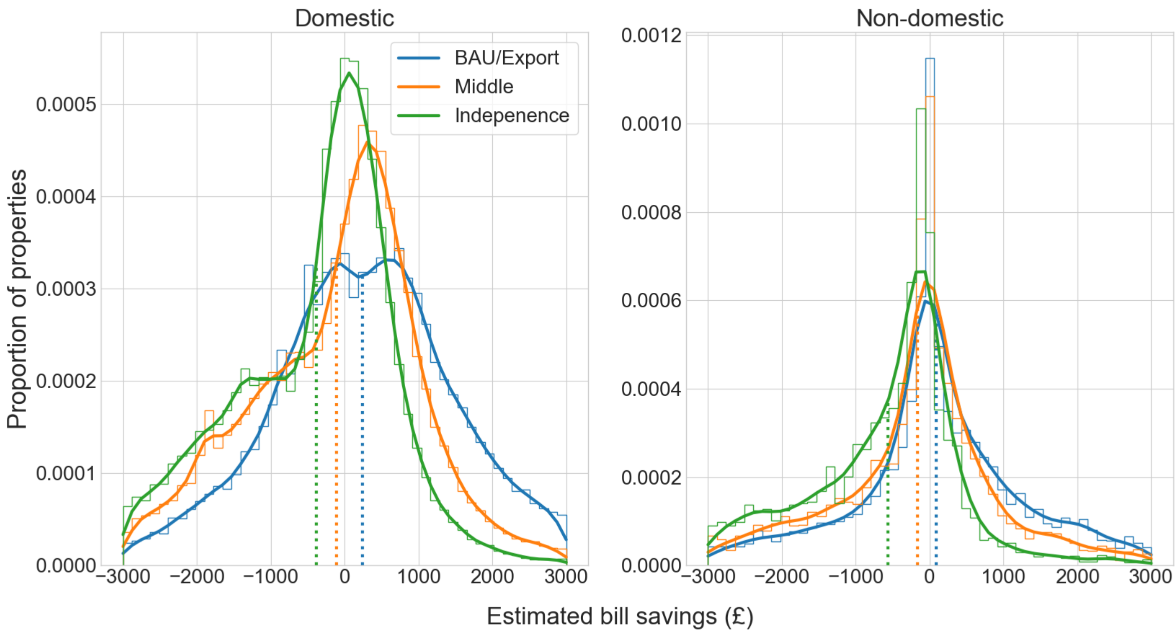

Figure 4-25: Annual bill savings (negative) relative to the baseline year, assuming an electricity price of 30p /kWh. The dashed line is the average in Table 4-7. Costs for baseline year non-electrical heating and transport fuel are not modelled (Matthew, 2024b).

Table 4-7: Change in bills and proportion of properties with increased electricity bills. Heat pump deployment in the Independence scenario is 100%, so there is no direct electric heating (Matthew, 2024b).

	Change in bill (£)			*Proportion with bill increase*		
Scenario	*BAU/ Export*	*Middle*	Independence	*BAU/ Export*	*Middle*	Independence
Domestic	+245	-107	-381	58%	53%	42%
Non-domestic	+94	-167	-559	51%	44%	23%
With heat pump	-9	-159	-393	54%	53%	42%
Direct electric heating	+661	+468	-	66%	64%	-

4.7.5 Demand side response potential

DSR potential has been calculated separately using a scenarios-based rate of participation from Table 4-5 of 50% (Independence), 25% (Middle Way), and 0% (BAU and Export). Applying these rates to the categories of heating, private transport, and hot water, hourly profiles of DSR potential were developed. Looking at an average winter day for the Independence demand scenario (Figure 4-26), at peak demand in the evening the contribution of both heating and hot water is approximately equal at ~13 MW. The peak DSR demand of 27.7 MW represents 23% of the demand, at the lower end of the 22-42% forecasted in FES (National Grid, 2023).

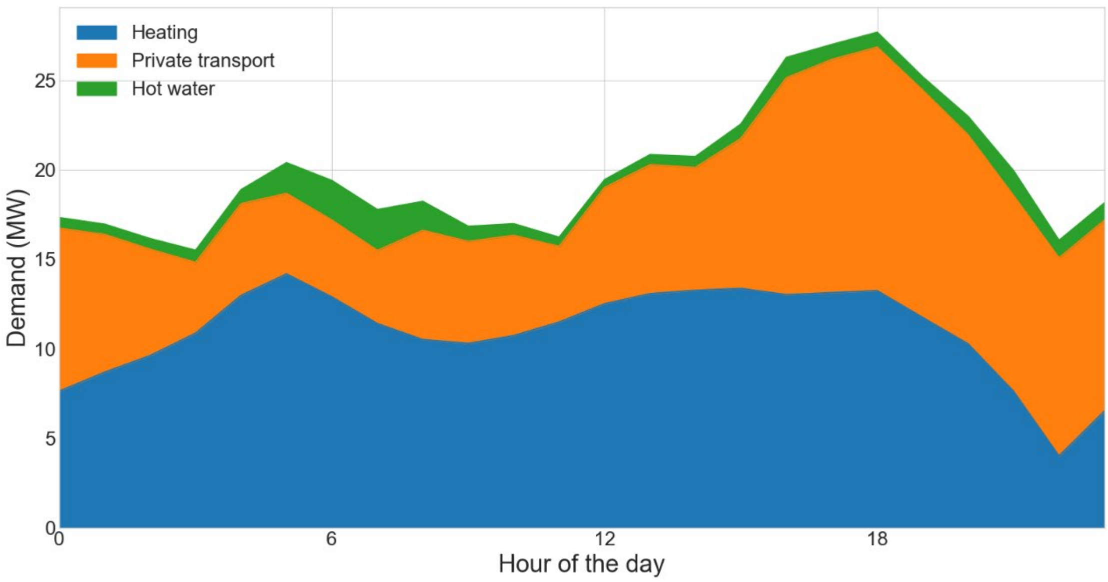

Figure 4-26: All islands DSR response for an average winter day for the Independence scenario (assuming a 50% participation rate).

4.7.6 Costing of demand scenarios

The overall CAPEX costs between scenarios can be compared for each category (Figure 4-27), noting that this cost would be annualised up until 2045. Building efficiency improvements are by far the largest cost group, making up three quarters of the total cost for all scenarios. The largest single category is heating technology as heat pumps are more expensive than the alternately modelled electric storage heaters. Although the modelled current heat pump costs could come down 20% by 2030 (UKERC, 2023), it would still be the largest cost category. Other costs are less likely to change as significantly. However, building fabric and solar water heaters costs taken directly from the EPC database, have been shown to be error prone (Hardy and Glew, 2019), therefore these sectors are likely to have the largest error.

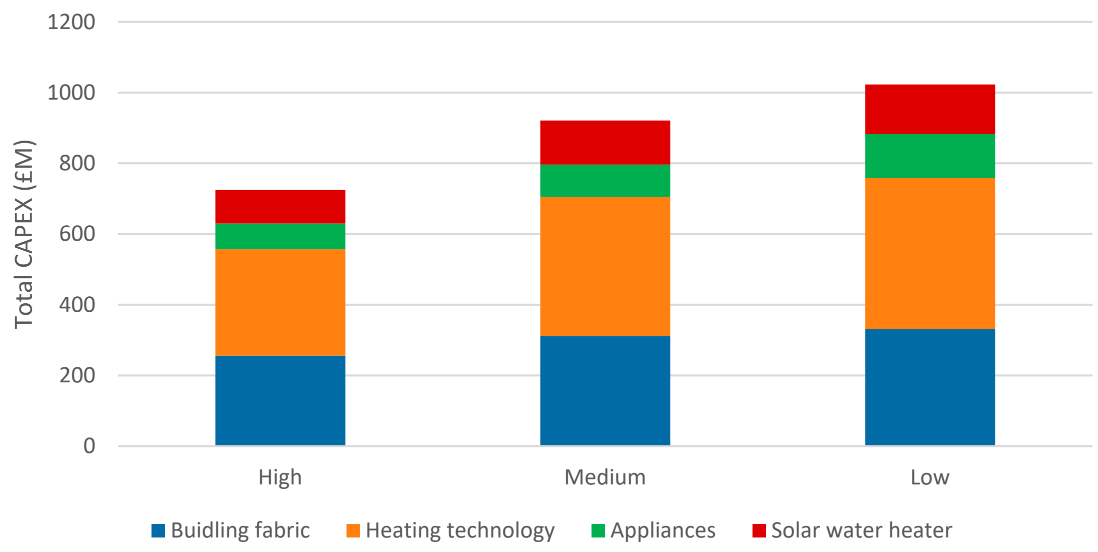

Figure 4-27: Total CAPEX for all measures across the demand scenarios.

The fact that so many households are recommended solar water heaters as improvements in the EPC database is perhaps surprising given the northern latitude of the islands. An over-recommendation of rooftop solar PV as an improvement from the EPC database was identified, discussed in more detail in Section 6.5.2, which could also be occurring here.

The average cost per household shows that even the cheapest option (the BAU/ Export scenario) could be significant (Figure 4-28). The average change corresponds to a cost of approximately £10,000 per household per EPC rating, which across the whole UK would be significant to improve all buildings up to touted minimum EPC standards.

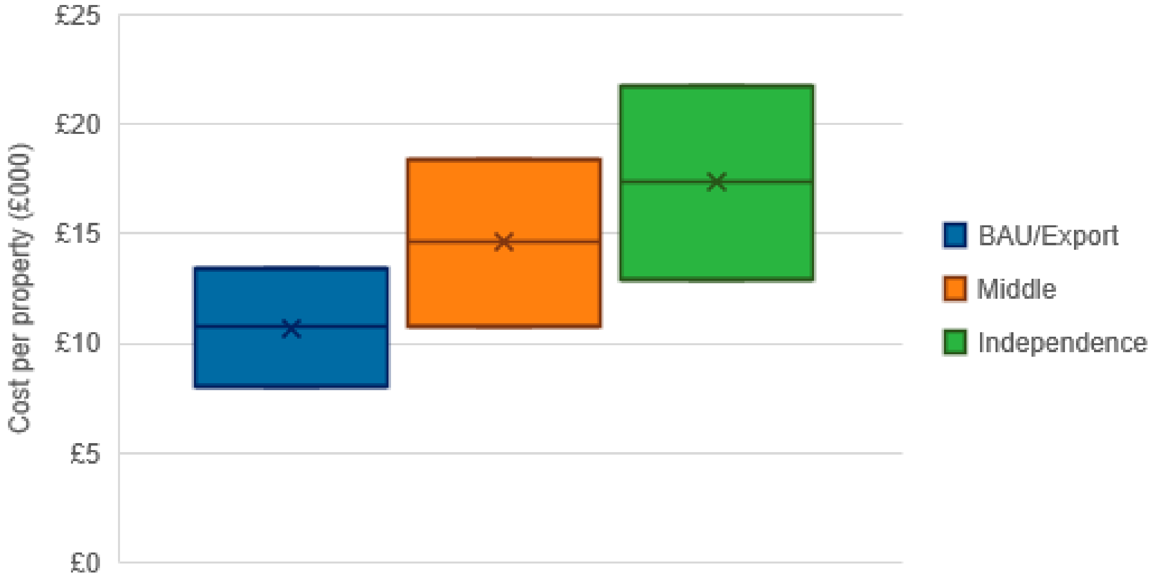

Figure 4-28: The range of average costs per property to upgrade by the number of EPC grades to the new grade indicated by the callout.

4.8 Discussion of electricity demand model scenarios results

To reach Scotland’s net-zero goal in 2045, the three scenarios represent annual demand changes of +0.6%, -1.3%, -3.2% for the BAU/ Export, Middle, and Independence scenarios, respectively (the IEA's net-zero pathways advocates for -4% annually) (IEA, 2022a). Projection of existing policies (BAU/ Export scenario) could lead to electricity demand increasing by 21% and peak demand by 58%. Electrification of heating and transport would outweigh savings in industry, appliances, and lighting. Given that around half of island properties currently rely on electric heating, the impact would be much more pronounced for the rest of the UK, which is reliant on gas for heating. Grid constraints on the islands could limit this growth, the trade-off of which will be examined in the results of the Net Zero model (Section 7).

Excluding heating to better match with the mainland UK, the peak demand increase of 2.3 from the baseline year to the BAU/ Export scenario aligns with similar projections of 1.5-2.9 (Bobmann and Staffell, 2015; Watson, Lomas and Buswell, 2019; National Grid, 2023). Heating (making up 35-39% of peak demand by scenario) and electric vehicle charging (25-40%) are the main contributors. Enhancements solely for these sectors could yield a 33% reduction in peak demand from the BAU/ Export scenario. The standard heating profiles were assumed for heat pumps and overnight usage for storage heaters, yet further reductions are possible with digitised and more intelligent demand profiles. Given the island stock’s currently low EPC rating though, building fabric upgrades are needed to maximise these benefits. The rise in demand from electric vehicle charging (23-24% of annual and 21-23% of peak demand) underscores how it can play a critical role in ensuring grid stability and diminishing dependence on peaking generation. Enhanced flexibility in EV charging (especially in conjunction with generation) or heating, could potentially mitigate the modelled peak demand increases. Policies incentivising more intelligent EV charging and flexibility measures will have crucial benefits to electricity networks.

Heat pumps will be critical to realising efficiency benefits. They significantly reduce both annual and peak demand - the main factors dictating overall system size and cost. In contrast to direct electric heating, they could save 2.0 kW of peak demand per property. When extrapolated to the 28 million households in the UK, this could result in a national peak demand reduction of 56 GW or approximately current peak demand. Considering model uncertainties, such as building stock variation or heating behaviour changes (discussed below), even half of this potential reduction would be noteworthy. Heat pumps can also improve energy efficiency for hot water. Despite these benefits, historic rates of heat pump installations indicates that targets will not be met under the existing policy framework (BAU/ Export demand scenario), with only 58% of households adopting them by 2045. While the recent government initiative to increase heat pump grants by 50% to £7,500 (DESNZ, 2023f) is commendable, how well it encourages confidence in the heat pump market remains uncertain, especially considering the simultaneous commitment to trialling hydrogen for domestic heating (DESNZ, 2023i). Changes in modelled electricity bills highlight that businesses could face a similar uneven distribution of decarbonisation costs as households. Given the closure of the RHI as the main non-domestic low-carbon heating support mechanism, similar policies could be needed to encourage non-domestic sector uptake.

To maximise the benefits of heat pumps, upgrading building fabric would also be needed. Annual demand results indicates that heat pumps alone could reduce heating demand by 2.6 times, increasing to 4.0 times with building fabric enhancements. The model accounts for interactions between heat pumps and building fabric upgrades through the air change rate variable in EnergyPlus, which has been used to calibrate the heating model (Section 4.2.4). Results therefore consider the inefficient use of heat pumps in poorly insulated homes, indicating that heat pumps alone would be an improvement on direct electric heating, but less so than if combined with fabric upgrades. Enhanced building fabric not only reduces demand but also enables continuous heat pump operation or DSR. Although not modelled here, improved heat retention in buildings also contributes to additional health benefit by creating warmer, better-insulated homes (Citizens Advice, 2023). This is particularly crucial for the islands, characterised by some of the highest fuel poverty rates in the UK (Orkney Islands Council, 2017a). Comprehensive measures, such as the forthcoming Future Homes Standard with projected upgrades to minimum building efficiency requirements, will be necessary. Setting ambitious energy efficiency targets in building standards could especially beneficial, as measures integrated into new constructions might be more cost-effective than subsequent retrofitting to meet later targets.

Industrial electricity demand (13-16% of annual demand) ranks third after EVs (23-24%) and heating (16-20%). It has the highest potential reduction in peak demand each day (though not in the peak demand day, which is primarily heating). This result depends on the major simplification that net-zero pathways for the whisky industry could be applicable to farm, fish farming, and fish processing. The approximation of industrial demand relied on annual sources for electricity only, neglecting the growing electrification of other demand types, which could negate the anticipated savings for heat-intensive distilling. A more granular industrial model with process energy demands is needed to improve this, but, the heterogeneity of industrial demand complicates this (Fleiter, Worrell and Eichhammer, 2011). A more nuanced understanding of specific efficiency and decarbonization options for different industries would facilitate the design of policies tailored to support each industry's potential for efficiency improvements. Technology neutral policies, such as efficiency auctions used in Switzerland (Regulatory Assistance Project, 2022), can address the unique challenges of specific industries.

The cost modelling of metrics, like the 42% to 58% of households facing electricity bill increases and the upgrade cost of £8-22k per building, underscore the necessity for a "just transition" which can be facilitated through energy policy. This means ensuring that no household or business is unduly burdened in transitioning to net zero. Results show the potential for average reductions in household electricity bills (excluding the BAU/ Export scenario), but even in the most optimistic Independence scenario, 42% of properties could be left with a higher bill due to heating and vehicle electrification. Achieving the Scottish Government target for the social rented sector on the islands to attain EPC B could incur costs of up to £22,000 per household - likely more for the least efficient buildings. This emphasises the point that, without financial policy support, efficiency improvements and their benefits are only achievable for the affluent (Kokoni and Leach, 2021). A review of inequalities in health stresses how health outcomes and sustainability issues go hand in hand through a “proportionate universalism” approach - meaning the scale of action should be proportionate to the degree of disadvantage (Marmot, 2010). Prioritizing support for those less financially able (not just the least able) to afford efficiency upgrades should be a pivotal element of energy policy, particularly considering the systems benefits described in Section 7.

Only technological changes are considered by the model, which omits some of the intricate interactions between technologies, behaviour, and the resulting efficiency. The "rebound effect," where anticipated energy savings from more efficient technologies are reduced (but in some instances increased) by altered usage, varies across sectors and technology types. Economy-wide estimates it at up to 10% for transport and up to 30% for heating (UKERC, 2007). However, changes in technology, such as heat pumps, could influence heating demand patterns (Terry and Galvin, 2023). It could mean having more appliances or driving further in more fuel-efficient vehicles. Additional behavioural changes, especially stemming from non-energy policy-specific effects (Royston, Selby and Shove, 2018), are unaccounted for but could substantially affect demand. Whilst this could mean that the savings compared to the validation year are reduced, it is not clear what effect this would have on the differences between scenarios. These results are likely an upper bound of potential savings. The implications for this for the Net Zero model are discussed in Section 7.4.2.

5 Towards circular biowaste utilisation for energy systems

The islands have been identified as having a notable potential of biowaste which could be used for energy. To quantify this, a techno-economic model has been developed. It consists of four sub-models (Figure 5-1), which each factor in separate constraints on energy potential - the available resource, transportation costs, facility configurations, and alternative demands for the resource. Research did not identify any existing anaerobic digestion facilities of scale on the islands. The CCC has argued that unabated waste incineration, with or without energy recovery should be minimised to meet emissions targets (CCC, 2023), therefore only anaerobic digestion is considered, All section of this chapter (excluding Section 5.5) are described in a published work (Matthew and Spataru, 2023b), with models developed in Python 3.8 (Python Software Foundation, 2022) which are available online (Matthew, 2023b).

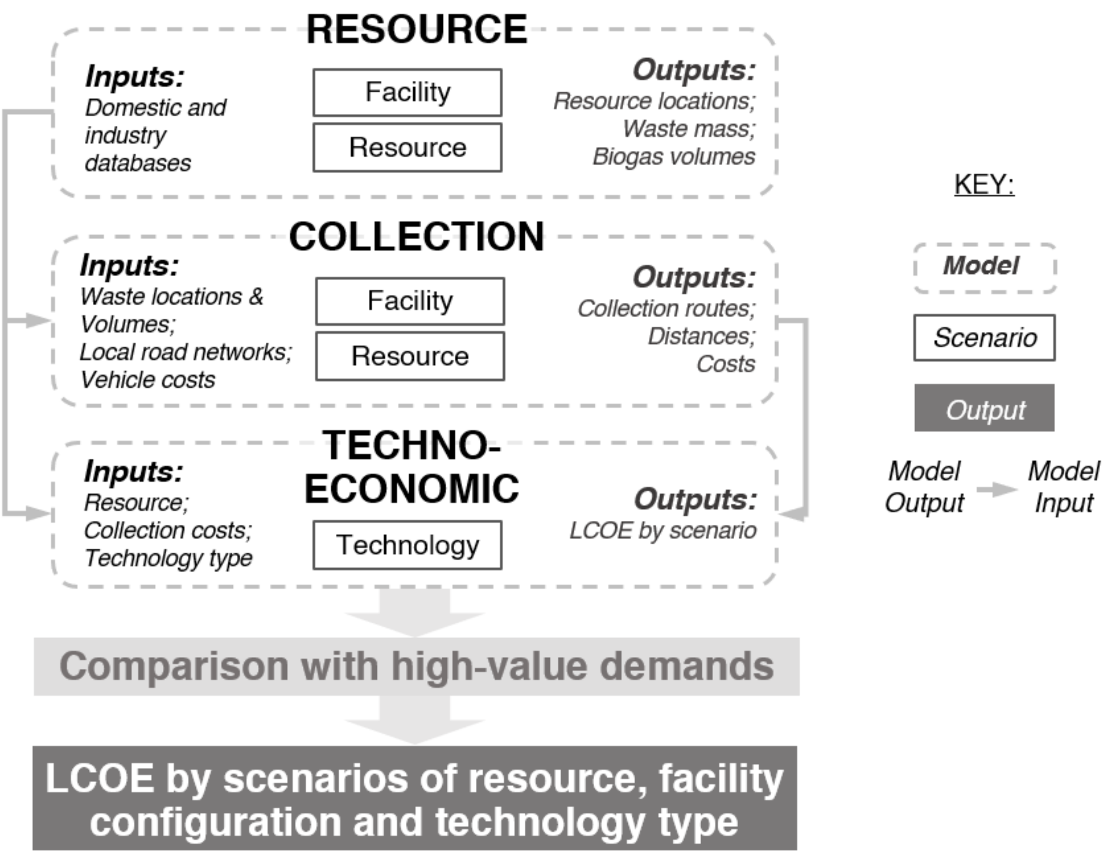

Figure 5-1: Flow chart of the biowaste model.

Scenarios of inputs are modelled (Figure 5-1), including facility types, energy conversion technologies, resource availability and competition with other demands. By employing these comprehensive sub-models and scenarios, the interconnections between various sectors can be examined. This highlights the factors that influence the feasibility of and potential for waste-to-energy facilities on the islands. It also provides a detailed and location-specific characterisation of the waste which could be used for biowaste on the islands, including whether the energy potential would be most economic to generate electricity, heat, or both. The outputs of this are used to input supply-side data in the form of energy costs and generator technical characteristics to the Net Zero model (Chapter 7).

A comprehensive database of resources (Section 5.1) has been developed for six distinct waste categories, with data on volumes, energy potential, and locations. This combines previous resource assessments identified in the literature which only addressed single resource or industrial sectors, allowing synergies between sectors to be more clearly identified.

The collection model (Section 5.3) adopts a CVRP (Perron and Furnon, 2022) solver with a recursive-DBSCAN clustering algorithm (Bujel *et al.*, 2018) to optimise waste collection routes. For the remote and poorly connected Scottish islands, collection costs are likely to be a limiting factor, so the model utilises actual street networks, distances, and ferry costs to improve on methodologies identified in the literature.

The techno-economic model (Section 5.4) uses the outputs of the resource and collection models, alongside generation technology types to calculate the LCOE. Scenarios of resource availability, technology type, and facility configuration are compared to understand the factors affecting economic viability and optimise for each island area (Section 5.1).

Resources in the database have been selected to minimise potential conflicts-of-use with other potentially higher-value options. This has however been assessed in sectors (whisky distilling and beer brewing) where alternative uses could be feasible (Section 5.5).

Finally, comparison of the LCOE and other metric demonstrates how the islands context and facility configurations affect the cost of energy (Section 5.6). The final results, which are used as energy inputs for the main model, are then discussed.

The novelty of the work presented in this chapter consists of the following:

(i) *Biowaste database development:* a biowaste database is developed from several sources, detailing types of waste, locations, and energy potential that has been made freely available for use in further work (Matthew, 2023a).

(ii) *Waste collection cost calculation methodology:* actual OSM street network data, recursive DBSCAN clustering, and a CVRP solver are combined in a framework which allows accurate modelling of waste collection costs, which could be simplified into a tool for local authorities to calculate waste collection costs.

(iii) *Techno-economic modelling:* a framework is developed to compare the influence of different factors on the overall cost of energy from biowaste, which is used to inform policy recommendations and could be adapted to other geographic areas.

5.1 Cost of energy determinants: resource availability, facility configuration, and generation type

Different categories for facility capacity, location, generation type, and resource will be considered in detail (Sections 5.2-5.4). The geographical layout and diversity of waste categories differ noticeably across regions, impacting resource availability, facility catchment area, and technology suitability. Anaerobic digestion plants situated nearest waste and demand centres will minimise waste and energy transportation costs. Alternatively, smaller islands without industrial hubs may find it more economical to optimise transportation costs for grouped waste streams. To assess these options, three options are modelled for each of the facility configuration, generation technology type, resource availability (Figure 5-2).

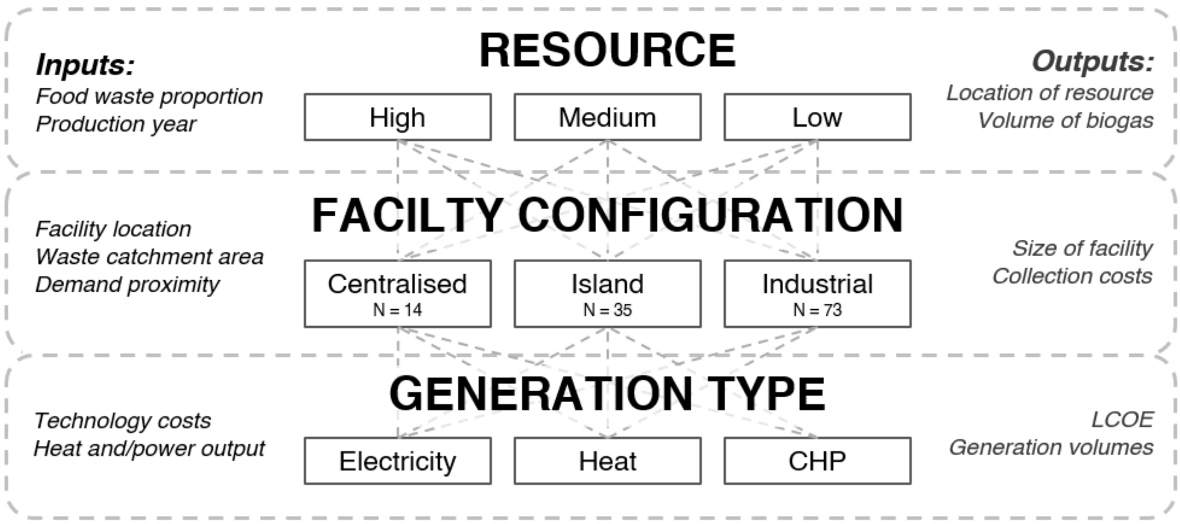

Figure 5-2: Modelled categories of inputs and outputs (Matthew and Spataru, 2023b).

5.1.1 Facility configuration

The most significant influence on the CAPEX and OPEX will be the number and coverage of facilities determined by their catchment areas. Facility location plays a crucial role in modelling regional capacity as it affects waste transport and energy export. To comprehend the interplay between economies of scale, collection expenses, and energy distribution costs, three facility size options have been considered for a total of 122 facilities:

(i) *Centralised facilities:* The 75 inhabited islands are grouped into 14 collection areas with a facility each (Figure 5-3) based on ferry connectivity and the serviceable area within an 8-hour working day. This option will the highest

anaerobic digestion and heat/electricity generation capacity, leading to lower facility costs per MW, but also the highest transport costs.

(ii) *Island facilities:* Each cluster of the 35 road-connected islands has an anaerobic digestion facility, eliminating ferry-based waste transportation costs and reducing road transport expenses, but at the trade-off of having more numerous, smaller facilities with higher CAPEX and OPEX.

(iii) *Industrial facilities:* Each industrial site with a potential generation capacity exceeding 10 kW or island group without an industrial facility will have a facility (73 in total). Waste from other locations will be directed to the nearest facility, resulting in a 94.4% reduction in waste transportation costs by weight.

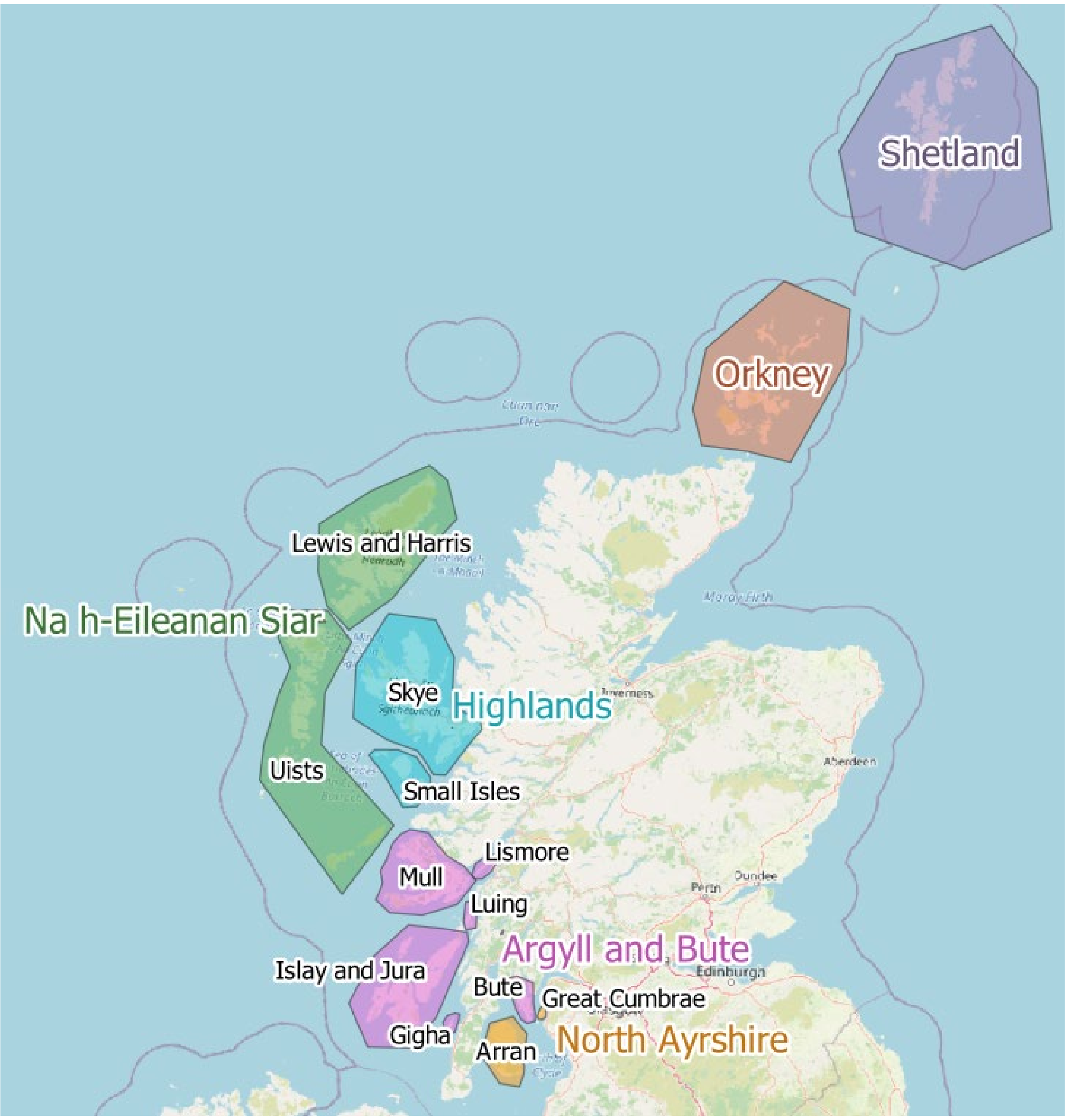

Figure 5-3: Modelled resource collection areas in black font, with local authority areas grouped by colour (Matthew and Spataru, 2023b).

5.1.2 Energy generation types

Anaerobic digestion emerged from the literature as the most appropriate technology for generating biogas from the wet waste streams available. Some studies focusing on distillery waste have explored the possibility of pre-treatment to enhance anaerobic digestion biogas yields. Pre-treatment is not considered as in other studies it simply highlights the difference between options with and without pre-treatment (Weber and Stadlbauer, 2017; Gunes *et al.*, 2019; Kang *et al.*, 2020; Ruiz, 2021), rather than changing the overall conclusion regarding the suitability of anaerobic digestion.

Considering mixed waste streams and the limited impact on the end use of biogas, this analysis will solely focus on anaerobic digestion. When utilizing biogas from anaerobic digestion, the model will consider electricity generation (reciprocating engine generator - REG), heat production (biogas boiler - BB), and combined heat and power (CHP). As a cut-off for REG, the smallest UK grid-connected generator of 2.5 MW was used (DESNZ, 2023d). Although AD facilities more commonly inject biogas into the gas network (DESNZ, 2023a), the Scottish islands have no gas network. Techno-economic data used for each is described in Section 5.4.

5.1.3 Resource availability

Data collection for all resources varied between 1990 and 2021, incorporating as many available years as possible for each dataset to examine annual variations and determine representative average values. Waste availability, which determines the sizing of waste-to-energy plants, might be subject to external market influences or behavioural demands that take precedence over using waste for energy. For instance, fish farming biomass has 80% increased over the last 15 years (Scotland's Aquaculture, 2021), whereas cattle numbers on the islands have declined approximately 0.7% since the 1970s, in line with the national trend (EDINA, 2021).

To encompass these dynamics, three waste scenarios were modelled: High, Medium, and Low. For industrial waste streams (including farms, food processing, breweries, fish farms, and distilleries), market demand-based waste production factors were used (described in Section 5.2). While some industries had unique factors influencing waste production, others relied on the same datasets (e.g., the Agricultural census for food processing and farm mortalities). To account for this, specific years were identified for each aggregated local authority for the High, Medium, and Low scenarios.

Food waste is more affected by the rate of household participation than annual variation. Research has characterised rates of less than 35% as poor, 35-55% as average, and greater than 55% as good (WRAP, 2021). Participation rates of 30%, 45% and 60% were therefore used for Low, Medium and High food waste scenarios.

5.2 Developing a biowaste database

The resource database was compiled with data from the most relevant datasets identified. Specific waste types to include were selected from review of bioenergy in Scotland which identified potential on the islands (Ricardo Energy & Environment 2019). Waste types were selected to minimise competition with other, higher value demands for waste (see Section 5.4). For fish farm waste, data was directly reported. However, for all other waste types, data had was estimated by combining inputs from multiple sources with Equations 5-1 and 5-2. For transportation vehicle costs, waste was categorised as either liquid or solid. For a comprehensive overview of the total waste, data sources, and supporting calculations described in the following sections, refer to Appendix B.3. The biowaste database is available online (Matthew, 2023a).

$$Local\ Production\ (tonnes) \times Waste\ Factor\ (\%) = Waste\ (tonnes) \qquad \text{Eq. 5-1}$$

$$Waste\ (tonnes) \times AD\ Energy\ Factor(MWh/tonne) \ = Energy\ (MWh) \qquad \text{Eq. 5-2}$$

5.2.1 Food waste

Datasets for household and business food waste were constructed with local household and business data from the demand model (Section 4) and national waste estimates per property (WRAP, 2020). This yielded an annual food waste amount associated with each building location. The process from the demand model in assigning households and businesses to building locations was reused here to assign waste to specific locations based on the building occupancy (as well as for the other waste types of farming, food processing, distilling, and brewing).

Average annual food waste values for non-domestic occupancies (WRAP 2020; Tesco 2017) were matched with business footprints (BEIS 2016a), to get average annual food waste per square metre for calculations and values. This factor, combined with local floor areas, provided an annual waste mass per property.

5.2.2 Farm fallen stock

The waste originating directly from farms was attributed to on-farm mortalities of sheep and cows from natural causes - known as 'fallen stock'. This was sourced from agricultural census data (EDINA, 2021) and national average fallen stock rates (Rural Payments Agency, 2023). To calculate the average mass of fallen stock per year for each farm, livestock density values from the Agricultural Census data were combined with the national proportion of fallen stock per year and the average weight of livestock (550kg for cattle and 54kg for sheep) (Rural Payments Agency, 2023).

5.2.3 Fish farm fallen stock

Fish farm waste of mortalities had the only directly recorded dataset (Scotland’s Aquaculture, 2021). Monthly reports detailing the total biomass present for each fish farm included the monthly mass of mortalities. Since over 97% of the biomass was Atlantic Salmon, this was the only species taken into consideration. As fish farm are located offshore, it was assumed that the waste resources would be transported to the nearest port for collection.

5.2.4 Food processing waste

To minimise competition with other higher-value resource uses, food processing waste was limited to wastewater from fish, meat, and dairy sectors. The wastewater for each was determined using local production data and conversion factors (see Appendix B.3). Food processing facilities were identified and matched to the demand buildings database (Section 4.2) using the register of Scottish food processing sites (Food Standards Scotland, 2022).

For fish processing, annual fish landings by port (Marine Management Organisation, 2016) and fish farm biomass (Scotland’s Aquaculture, 2021) were aggregated and allocated to the nearest fish processing facility. 70% of the local catch was assumed to be exported with no further processing (Tetley, 2016). The proportion of wastewater for fish processing was directly available (Chowdhury, Viraraghavan and Srinivasan, 2009), and the energy content was estimated based on other relevant values (Appendix B.3).

For dairy processing, the number of dairy cows (EDINA, 2021) and estimated yield per cow (WRAP, 2020) was used to estimate local production, then assigned to the nearest food processing facility. The fraction of wastewater and the estimated energy content were then calculated (Appendix B.3).

Similarly for meat processing, number of cows was used to estimate the annual production (EDINA, 2021). However, unlike dairy processing, a proportion of cattle are exported live from the islands, so this was assumed to be 70% as for fish processing (Tetley, 2016) for lack of equivalent data.

5.2.5 Whisky distilling waste

Waste generated by distilleries consisted of three types (draff, spent lees, and pot ale) with varying biogas yields (Ricardo Energy and Environment, 2019). To estimate each waste stream, known proportions per unit production and the capacity of each distillery were used. Distillery production was based on the facility's production capacity (Gray, 2020) and a production factor derived from the annual Scottish whisky production

(Bell, Farquhar and Mcdowell, 2019; Gray, 2020). Waste and energy were assigned to each distillery location in the buildings database.

5.2.6 Beer brewing waste

While beer brewing is much smaller than distilling on the islands, it was included for completeness. Brewery locations were used from the demand model buildings database. To estimate production from polygon areas, production factors were utilised, along with a factor of 50% to account for other building uses. Brewery waste also had three distinct forms: spent grain, spent hops, and spent yeast, with varying energy potentials (Appendix B.3).

5.3 Collection costs optimisation for actual road networks

Collection routes for both liquid and solid waste types were optimised using the CVRP solver, developed with Google's OR-tools (Perron and Furnon, 2022). This utilises a nodal distance and demand matrix from the biowaste database (with locations based on the Demand buildings database - Section 4.2) as the primary input. Specific distance data obtained from the OSM road networks (Boeing, 2017) was used to calculate the distance matrix. Collection was planned to occur once every two weeks. The key outputs of this optimisation process (utilised in the economic model - Section 5.4) include the number of vehicle days required per facility, fuel costs, and ferry costs.

5.3.1 Calculating the distance matrix using OSMnx

The primary input for the CVRP solver is a matrix of the shortest distances between each node. This was calculated using the OSMnx Python package (Boeing, 2017). Data on road types in OSMnx graphs, were converted into costs and time metrics. Data was collected on the duration and costs of the 80 ferry routes, based on the ferry demand modelling (Section 4.3.2) (Caledonian MacBrayne Ferries, 2022; Orkney Islands Council, 2022b; Shetland Islands Council, 2022) incorporated into the OSMnx network graphs. To ensure that the routes fit within the constraints of a typical working day, (with some ferries taking more than two hours), an 8-hour day was used as a constraint. Road type information from the OSM graphs was utilised to estimate the travel speed (Appendix B.3) and travel time between nodes.

5.3.2 Waste collection area configuration

The collection areas were varied with the facility configuration scenarios (Section 5.1). In the Islands scenario, the catchment area was defined as each island. In the Industrial scenario, the catchment area was determined as the shortest travel time from each industrial facility above a threshold energy potential on each island. For the Centralised scenario, catchment areas were assigned based on the approximate area that could be covered within a day's travel (Figure 5-3). This approach ensured efficient and manageable collection areas for the centralised waste-to-energy facilities.

To identify locations for non-industrial anaerobic digestion facilities, the Local Development Plans of each local authority were utilised (EDINA, 2021) (also used as a constraint on electrolysis and BESS capacity - Section 6.4.3). These classify land areas based on their suitability for types of development, such as existing housing, protected areas, or economic development zones. Locations for anaerobic digestion facilities were identified by considering land classifications suitable for economic or industrial development.

For both the Centralised Facilities and Individual Island Facilities scenarios, the best location (from the constrained LDP land area) for each catchment area was assumed to be the one closest to the waste centre of gravity of each resource collection area. The centre of gravity was calculated using Eq. 5-3:

$$Centre\ of\ mass_{x,y} = \frac{\sum_0^n c_n m_n}{\sum_0^n m_n} \qquad \text{Eq. 5-3}$$

Centre of mass$_{x,y}$ = x/y coordinates of centre of mass; n = number of coordinates; c = nth x/y coordinate; m = nth mass.

5.3.3 Optimisation using capacitated vehicle routing problem (CVRP) solver and DBSCAN clustering

To optimise collection routes, Python and Google's OR-Tools solver (Perron and Furnon, 2022) were used with the inputs of distance matrix, vehicle capacities, vehicle numbers, and collection facility locations. Vehicles of 2.5T and 18,000L were assumed for solid and liquid collection vehicles respectively (Duguid and Strachan, 2016). The key outputs of this optimisation process are the time required for each collection route, the volume of waste collected, the distance travelled, and ferry costs. Where trips took less than the 8-hour working day, they were grouped to minimise the number of collection days.

For most waste streams, the OR-Tools solver was sufficient to optimise for the number of nodes. However, for food waste, the large node count (up to 5000) exceeded the computing power of the available 2019 Dell laptop (2.60GHz Intel i7-9850H CPU and 16GB RAM). For these larger problems, a recursive DBSCAN algorithm was used (Bujel *et al.*, 2018). This recursively clusters nodes into groups using the machine learning algorithm DBSCAN with similar numbers of collection points, then CVRP is applied to these clusters separately. The use of the recursive DBSCAN algorithm on smaller areas found a discrepancy of approximately 7% between its results and those of the CVRP solver, similarly to the study outlining the method (Bujel *et al.*, 2018).

5.3.4 Comparison of modelled and recorded waste collection costs

The collection costs modelled for domestic food waste only were validated by comparing with actual waste collection budgets (Scottish Government, 2022d) for each island-only local authority (Figure 5-4 - actual costs shown in bold). Note that the actual budget includes all waste types (only landfill and recycling as there is currently no food waste collection on the islands) (Scottish Government, 2022c). The modelled results, which consider only one waste stream and at most 60% of households for the high scenario, are therefore a proportion of this total. That the proportion of this cost (at the top of each bar) is reasonably constant across each local authority demonstrates that the collection cost model is representative of the actual waste transportation costs.

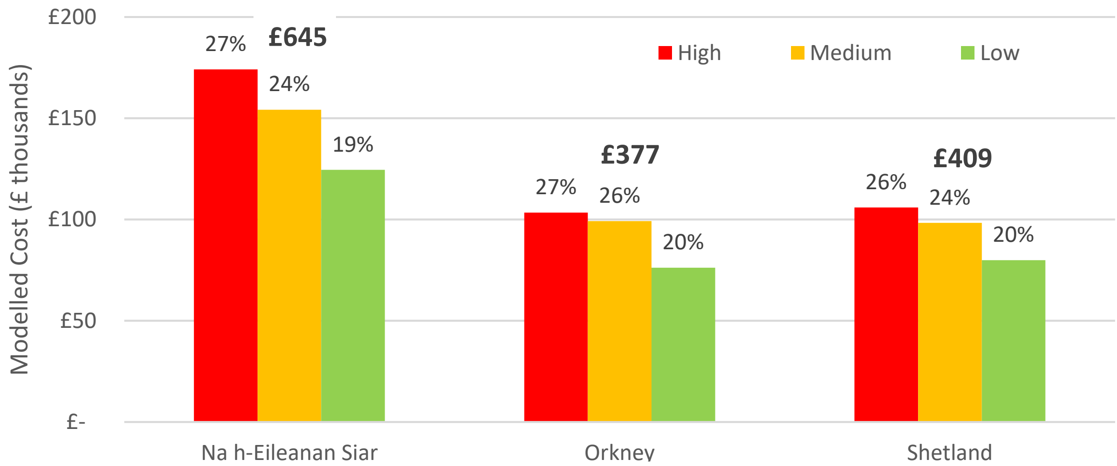

Figure 5-4: Household collection costs for food as a proportion of the entire waste collection budget by local authority (shown in bold), where scenarios of household participation in food waste collection rates are 30/45/60% for the Low to High scenarios (see Section 5.1.3) (Matthew and Spataru, 2023b).

5.4 Techno-economic modelling of energy costs

The resource database and collection costs are inputs to the techno-economic model. The anaerobic digestion and generation technologies were characterised by technical and economic aspects. Each of the three facility configurations (Section 5.1) was modelled with an anaerobic digestion plant and one of the three generation technologies: reciprocating engine generator (REG), combined heat and power (CHP), and biogas boiler (BB).

Waste available from each facility configuration was used to determine the size of the anaerobic digestion plant. The mass of waste, density (assumed as 1000kg/m3 or 500kg/m3 for liquid and solid waste respectively), and a retention time of 3 days were used to calculate the anaerobic digestion volume capacity (m^3), which was then used to calculate the associated costs. The feasibility of co-digestion for all waste types was not explicitly identified in the literature, however as the anaerobic digestion costs were modelled without a fixed element (e.g. independent of capacity), the number of digestors would not affect cost results. The energy available from biogas production was used for generation technology sizing using technical characteristics (as detailed in Table 5-1). The sizes of the anaerobic digestion plant (m^3) and the generation technology (MW) were then used to calculate the cost for each technology and facility configuration.

Table 5-1: Modelled technical characteristics (Duguid and Strachan, 2016).

Aspect	*Biogas boiler*	*Combined heat and power*	*Reciprocating engine generator*
Capacity factor	50%	90%	6%
Thermal efficiency	80%	41%	-
Electrical efficiency	-	39%	39%
Parasitic anaerobic digestion demand	20%	5%	10%

Other economic analyses of the region or sectors have employed payback times or the net present value (NPV), utilizing average fuel, heat, and electricity prices. However, these approaches highlighted the sensitivity of results to volatile energy prices (Duguid and Strachan, 2016; Kang *et al.*, 2020; Kassem *et al.*, 2020). To address this issue and separate assumptions about energy prices from the results, the LCOE is considered. This and the described technical characteristics will allow the biogas potential to be directly incorporated into the Net Zero model.

To calculate the LCOE, equation Eq. 5-4 was used with an economic lifetime of 20 years and a discount rate of 7.5% (IRENA, 2018). The Capital Expenditure (CAPEX) and Operational Expenditure (OPEX) was the sum of each facility cost aspect (Table 5-2). To assess the viability of individual schemes, the LCOE of each technology type is compared to benchmark costs of £130 /MWh for heat (EMEC, 2019a), £313 /MWh for REG, and £135 /MWh for CHP (BEIS, 2020b).

$$LCOE = \frac{\sum_{t=1}^{n} \frac{C_t + O_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}} \qquad \text{Eq. 5-4}$$

t = the year; C = CAPEX; O = OPEX; E = electricity generated; r = discount rate; n = economic life of project.

Table 5-2: Unit costs considered in the model (Matthew and Spataru, 2023b).

Aspect	*Type*[1]	*Description*	*Source*
Anaerobic digestion	C&O	CAPEX - £300 /MWh OPEX - £25 /MWh	(Duguid and Strachan, 2016)
REG	C[2]	£44,908 + (£372.43 x capacity)	(Allardyce *et al.*, 2014)
Biogas boiler	C[2]	£57,484 + (£13.97 x capacity)	(Allardyce *et al.*, 2014)
CHP	C[2]	£54,968 + (£475.62 x capacity)	(Allardyce *et al.*, 2014)
Biogas storage	C[2]	£3,000 /tonne	(Rural Futures, 2010)
Waste collection (per vehicle)	C&O	CAPEX - £50,000 OPEX - £6,250 OPEX (per driver)[3] - £28,000 Fuel costs – £0.96 /km	(WRAP, 2015); fuel costs (Madden *et al.*, 2022)
Grid connection	C&O	Connection (if <250 kWh: £938; else £2556) Annual charge (£6.43 per day – £0.75 x annual generation)	Connection (SSEN, 2022a); annual charge (SSEN, 2020b)
Heat network connection	C&O	CAPEX - £923 /MWh OPEX - £26 /MWh	(DECC, 2015)
Capital grant	C	50% capital costs	(Scottish Government, 2021d)
Avoided costs	O	See Table 5-3	

[1] C = capital costs; O = operational costs;
[2] OPEX calculated as 5% of CAPEX;
[3] Assumed two drivers/operators for food waste; one driver for liquid and animal waste.

Existing costs paid to dispose of waste were modelled as avoided costs (Table 5-3). These are considered as the costs which the waste producer would otherwise have to pay to dispose of the waste, whether to landfill (food waste), incineration (fallen stock), or water treatment (food processing). The LCOE was modelled including these costs as saved in disposing of waste.

Table 5-3: Avoided costs by waste type (Matthew and Spataru, 2023b).

Fee description	*Applicable waste*	*Rate (£/tonne)*	*Source*
Fallen stock disposal	Farm (cow)	200	(Robinson Mitchell, 2020)
	Farm (sheep)	155	(Robinson Mitchell, 2020)
Fish farm mortalities disposal	Fish farm	36.5	(Zero Waste Scotland, 2016)
Landfill tax	Food waste	98.6	(Scottish Parliament, 2022)
Wastewater disposal rate	Food processing and distilleries (spent lees)	1.6	(Scottish Water, 2022b)

Heat network costs were considered by the type of facility. For Centralised and Island facilities, where generation plants are standalone (e.g. not co-located with heat demand), additional heat network costs would be required. Industrial demand for heat depends on the specific industry. Distilleries, for instance, were modelled without heat network costs as the majority of their demand is for heat (Ricardo Energy and Environment, 2020) (Section 4.3.3). Other facilities with negligible heat demand would include heat network costs to connect with demand (DECC, 2015).

5.5 Minimising competing resource demands

Using biowaste for energy is just one potential circular economy pathway that each island or industry could pursue. Waste-to-energy competes with other resource demands which could have greater value. Understanding and balancing this will be crucial to ensuring that a reasonable energy potential is included in the Net Zero model (Chapter 7). This was considered by choosing waste categories as follows:

(i) *Food waste:* higher value products are generally only feasible (technically, not to consider the economics) when provided in separate waste streams (Teigiserova, Hamelin and Thomsen, 2019), therefore mixed household food waste would not be suitable for other uses.

(ii) *Fish and land farms:* fallen stock are categorised as animal by-products category 2 or 3, making them not suitable for human or animal consumption (UK Government, 2018), making it unlikely that alternative uses could be found.

(iii) *Food processing (fish):* animal by-products not suited for human consumption generally have more economical uses such as animal feed (Shaiith, 2015), therefore they were not considered in the waste database. Only waste-water was considered, for which anaerobic digestion has been highlighted as the most suitable alternative to disposal (Chowdhury, Viraraghavan and Srinivasan, 2009).

(iv) *Food processing (dairy):* as for fish processing, only waste water has been considered, which similarly has been found to be best suited to anaerobic digestion (Awasthi *et al.*, 2022).

(v) *Beer brewing and whisky distilling:* the range of by-products from these two sectors have many more potential uses including animal feed, fertiliser (Shaiith, 2015), and food applications (Chetrariu and Dabija, 2023).

Thus, only the resources considered here for energy in the beer and whisky sectors were identified to have significant potential for alternative uses, so they will be considered in this sensitivity analysis. After developing the biowaste database (Section 5.2), the bioenergy from beer brewing was determined to be insignificant (0.11% of the total energy) relative to the whisky resource (68.34%), so for simplicity only alternative uses for whisky by-products are considered.

Whisky production consists of three main by-products: draff (also referred to as spent grains), pot ale (or spent wash), and spent lees. For the energy content modelled in the biowaste database they make up 46.58%, 13.22% and 0.9% respectively of the overall biogas energy potential. Due to this, analysis of alternative uses for these products will focus mainly on draff and pot ale, although the solutions described below have similar applications for spent lees.

Traditionally, by-products have been given away to nearby farmers for use as direct animal feed due to their short shelf life and cost to transport (Shaiith, 2015). On islands where there is a lack of local farming demand to meet by-product availability (such as the distillery-dense Islay and Jura), by-products are also dumped in the sea (Aboubakry, 2015). Despite this, studies have highlighted several other applications, mainly centred around extraction of higher value proteins, but also other materials. In addition to protein, pot ale has lactic acid, succinic acid, lysine, magnesium, calcium, sulphur, copper, zinc and phosphate content. The potential yield of phosphate from distilling in all of Scotland is greater than half of the annual fertiliser consumption of Scotland (Edwards *et al.*, 2022). It can also be directly used as a fertiliser (Mohana, Acharya and Madamwar, 2009). Draff, additional to suitability as animal feed and protein extraction, also has potential for producing anti-oxidants, metabolites, lipids, minerals, and vitamins (Chetrariu and Dabija, 2023).

However, these alternatives do not necessarily compete directly with the potential for energy demand. Following extraction of higher value constituents, such as more protein dense animal feed, the leftover material may still be used for anaerobic digestion (White *et al.*, 2016). Review of the potential for whisky by-products in Scotland highlights two projects which are under commercial scale development currently. Celtic Renewables are in the process of building an advanced biofuels facility in Grangemouth using a fermentation process to produce acetone, butanol, and ethanol (for use in biofuels) from draff and pot ale, in addition to animal feed with a higher protein density. Horizon Proteins are developing process to extract protein from pot ale, with the remaining product still useable for anaerobic digestion (Shaiith, 2015). In synergy with other local industries, this has been proposed for specifically making feed for salmon farms (Aboubakry, 2015). Although much less technically mature, microbial reactors and photobioreactors have been proposed in theory, producing electricity, methane, and recycled water. Alternatively, extraction of polyphenols could also be feasible, but has a much lower technology readiness in Scotland (Shaiith, 2015). Lastly, production of microalgae from by-products could be feasible, but has also not been demonstrated at scale and would require expanding into a yet-untapped market (Phycofoods, 2022). Given that companies including Celtic Renewables and Horizon Proteins are already in the process of expanding operations to a commercial scale elsewhere in Scotland, these options of extracting higher-value protein first, followed by other energy content, seem more viable in the short to medium term.

In these alternative use cases, energy production does not rule out other potential uses. Either the material remaining after higher-value protein extraction could still be utilised for anaerobic digestion, or an alternative energy form could be produced (e.g. biofuels). In the former case, it is assumed that the remaining material suitable for anaerobic digestion would have a similarly energy content. Due to protein content partly inhibiting the anaerobic digestion process, comparison of untreated pot ale and de-proteinated pot ale for anaerobic digestion found the protein extracted pot ale had only a 9.6% lower methane yield (Barrena *et al.*, 2018b). For the latter, an alternative energy vector would still be produced from the biowaste - i.e. the impact on the energy balance of the overall systems model would likely be the same, just utilised in a different sector. As such, for the purposes of the Net Zero model, the effects of other high value products being produced from whisky industry by-products is unlikely to have a significant impact on the Net Zero model results.

5.6 Biowaste energy potential and costs

From the combined resource database, collection costs, techno-economic, and competing resource demand modelling, the potential energy from the islands' biowaste can be considered. The geographic distribution of energy by resource type (split by solid and liquid waste types) (Figure 5-5), highlights similar biowaste clusters as identified in another study - Skye, Mull, Islay and Jura, Orkney, and Shetland (Ruiz, 2021). Total potential energy equals 14.0-20.6% of the islands electricity demand in 2022 (BEIS, 2022f), which could contribute significantly to decarbonising the islands as a dispatchable, local energy source. Whether this can contribute significantly to decarbonising the islands will be clearer once the results are incorporated with the Net Zero modelling (Section 7.5.2).

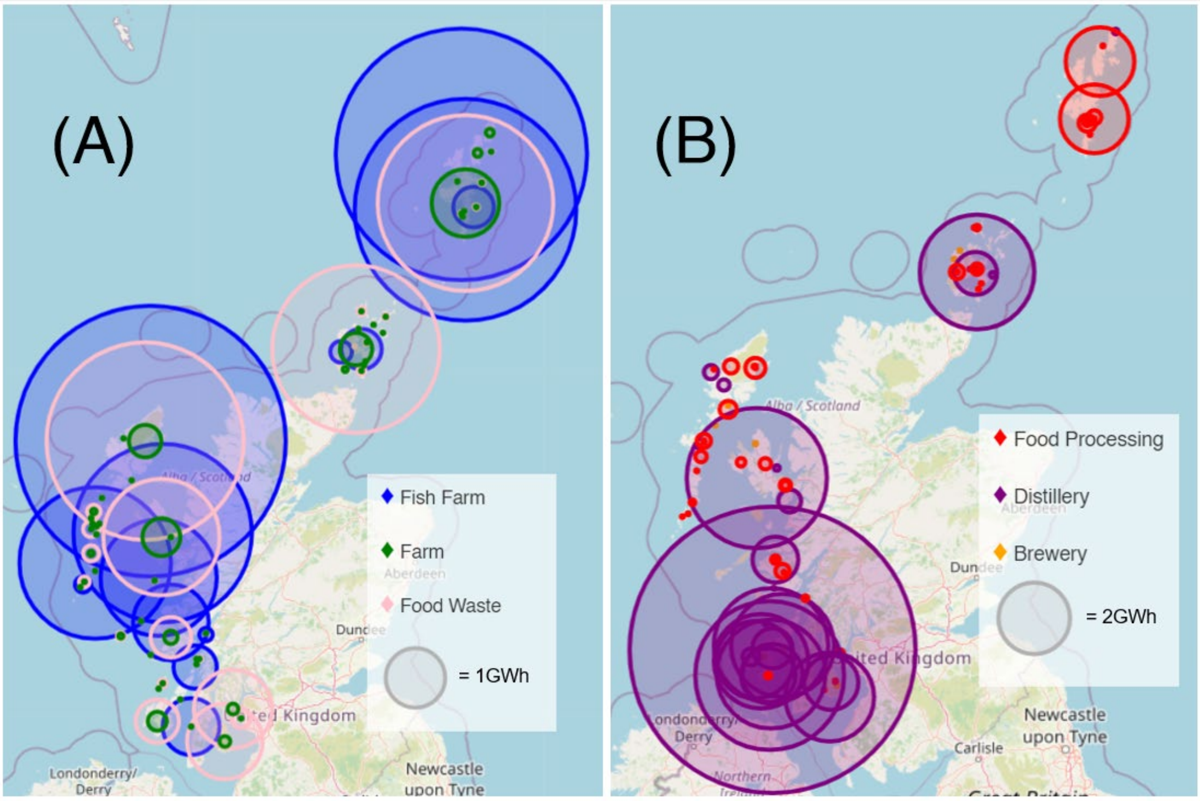

Figure 5-5: Solid (left) and liquid (right) waste for the medium resource scenario, with farm and food sectors grouped by island (Matthew and Spataru, 2023b). *Note the difference in scales* (Matthew and Spataru, 2023b).

As a sense check for distilleries as the largest category of biowaste (by mass and energy), energy was compared with another study of biowaste energy for Scotland (Table 5-4). The proportion of mass and energy from whisky distilling is ±0.6% by waste type, demonstrating comparable independent results. Comparing this 14.8% energy total with the gross value added (GVA) for food and beverages (which for the islands whisky will be a large proportion as the highest value export), the total energy sits in the middle of the range of 8.2-27.1% for the islands, which would be expected given the different regions which also include some mainland locations.

Table 5-4: Modelled waste and energy potential compared for the islands (modelled here) and all of Scotland in another study (Ricardo Energy and Environment, 2019).

Aspect		*Islands only*		*All Scotland*		*Proportion*	
		Mass (kt)	*Energy (GWh)*	*Mass (kt)*	*Energy (GWh)*	*Mass*	*Energy*
Whisky distilling	Draff	93.0	102.3	684.0	650.0	13.6%	15.7%
	Spent lees	52.1	0.2	361.0	1.1	14.4%	18.1%
	Pot ale	293.9	29.4	2,048.0	243.0	14.3%	12.1%
	Total	439.0	131.9	3,093.0	894.1	14.2%	14.8%

Table 5-5: Comparison of GVA (for the category of "Manufacture of food, beverages and tobacco") for different regions (ONS, 2023).

ITL region name	*GVA share*
Caithness and Sutherland, and Ross and Cromarty	9.3
Inverness and Nairn, Moray, Badenoch and Strathspey	63.6
Non-islands total	**72.9-91.8**
Lochaber, Skye and Lochalsh, Arran and Cumbrae, and Argyll and Bute	18.9[1]
Na h-Eileanan Siar	2.2
Orkney Islands	1.3
Shetland Islands	4.7
Islands total	**8.2-27.1**

[1] *Note that this category is split between the islands and mainland and includes the largest whisky producing region of Islay and Jura, which is likely the largest contributor.*

The regional and scenario differences in the LCOE (Figure 5-6) demonstrates how the islands' context affect the cost of energy. The clearest trend is that REG costs are much higher, mainly due to the lower assumed load factor (500 hours per year). For the larger islands (Islay and Jura to Mull), industrial facilities generally appear to have the cheapest energy, which would indicate that reduction of transport costs for these areas is the best way to minimise the cost of energy. However, for the smaller islands (Uists to Lismore on the right of Figure 5-6), this trend is less clear, with other options being cheapest in some cases. The local topography and resource availability clearly affects which solutions are best suited to each area.

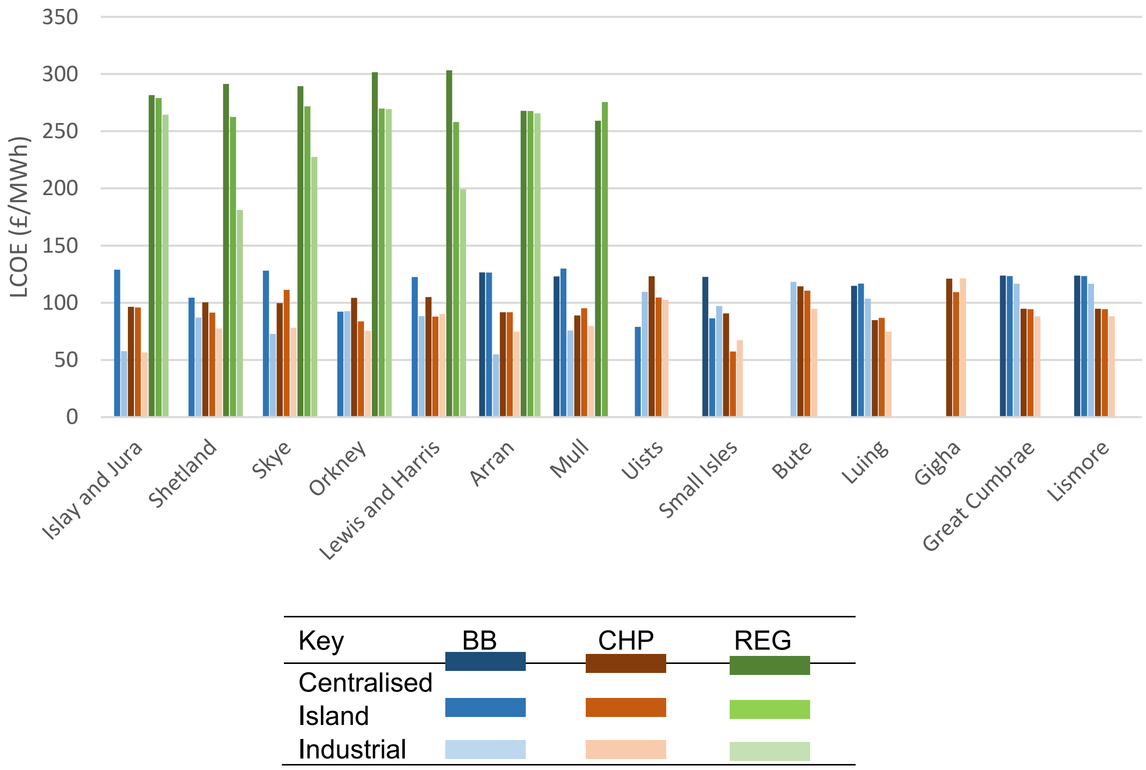

Figure 5-6: LCOE by technology and facility type, with regions ordered descending from the largest energy potential on the left (Matthew and Spataru, 2023b).

Consideration of local road-networks in waste collection costs has a clear effect on the final LCOE. Collection costs by weight are highly varied from £0.1-1670.0/tonne, which would not be represented by a cost-per-tonne metric. For dispersed, ferry-connected regions, these costs per tonne are generally reduced with more resource availability, but for larger road - connected islands, the reduction is clearer. In the smallest, most remote areas (the right side of the Figure 5-6), few facilities are economically viable as a results of excessive collection costs. Under this modelling framework, these isolated regions would miss out on utilisation of biowaste, but alternative, small-scale and bespoke solutions might be suitable depending on the local context.

Looking at the range of LCOE for all scenarios (Figure 5-7), the industrial facilities have the lowest LCOE for BB and CHP, but that this has a greater range. The lowest costs for these aspects will likely occur where heat network costs are not included (i.e. whisky distilleries), greatly reducing the overall cost. The higher end of the Industrial BB and CHP scenarios will likely have these costs included, hence the greater range.

The range of resource availability by modelled scenarios appears to have a minimal impact on the average LCOE (implications for interannual variation are discussed in Section 5.9). In all cases the average costs simply decrease slightly with increased energy potential - i.e. there is no effect related to the islands topography and collection routes which increase the overall cost with greater resource collection costs.

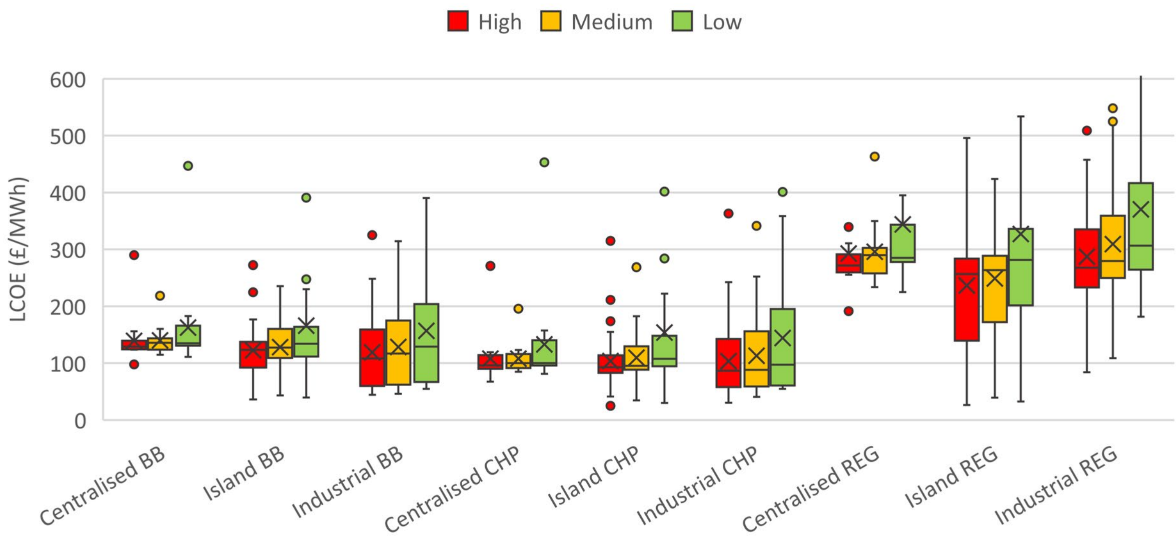

Figure 5-7: Comparison of the LCOE of all facilities by resource scenarios (Matthew and Spataru, 2023b).

Looking at the LCOE changes for industrial facilities with additional non-industrial waste excluded (Figure 5-8) demonstrates the geographic specificity of the model. Non-industrial waste has a higher energy content, but also higher collection costs. The graph shows that there is no trend, with additional waste streams in some cases increasing or reducing overall energy costs (factoring in the change in collection costs in the overall LCOE) depending on the local topography and energy content of the resource. Facility economics could clearly be optimised considering other waste types.

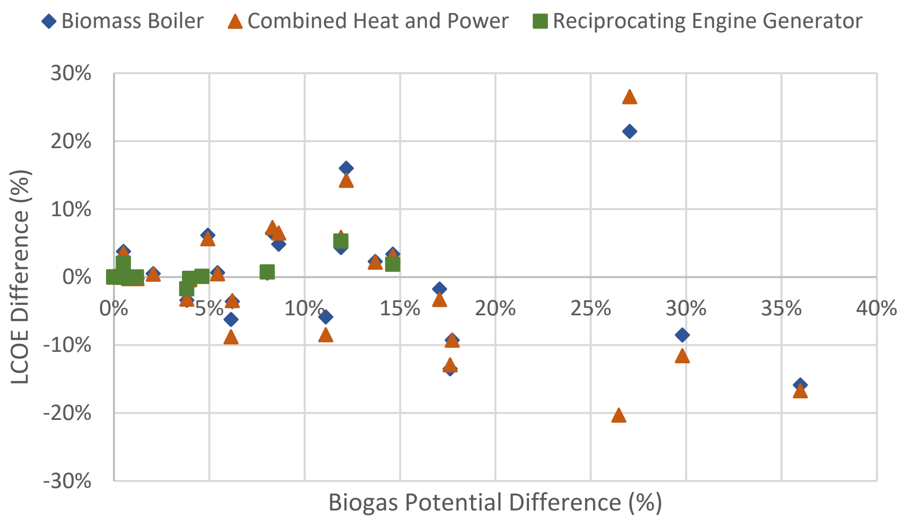

Figure 5-8: Change in LCOE for industrial facilities only if non-industrial waste is excluded from the potential biowaste/energy input (Matthew and Spataru, 2023b).

5.7 Sensitivity analysis of biowaste cost of energy

The Biogas model scenarios of Facility, Generation and Resource have been modelled to consider their impacts on the viability of biowaste-to-energy facilities. Other aspects were identified as having a significant impact, so variability has been modelled here to understand the effect on results. As factors that significantly influence the overall LCOE, uncertainty in avoided costs, capital grants and heat network costs have been considered. Separately, household food waste participation rates have been modelled to understand how this affects collection costs.

5.7.1 Avoided costs and capital grants

The model has been set up with capital grants and avoided costs (Section 5.4). Avoided costs are paid by waste producers for processing - this would likely need to be slightly lower than this to encourage switching. For the medium resource case, these range from 28-42% of OPEX with facility costs. Capital grants are set at 50% of CAPEX based on funding available and have been applied to all facilities. Both aspects will have a critical impact on the viability of schemes and so how much biogas could be economically available.

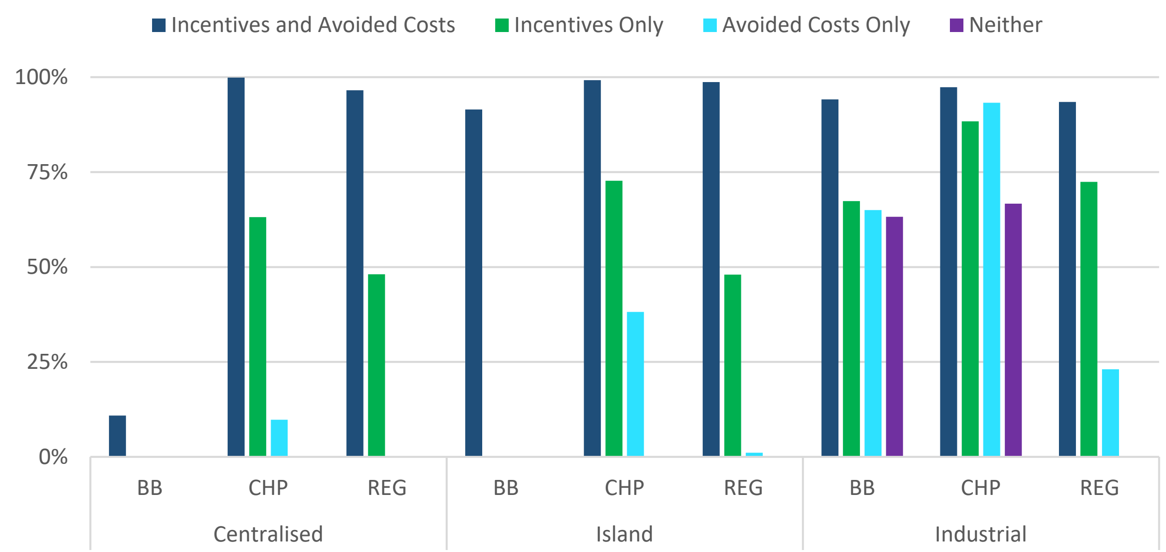

Figure 5-9: Proportion of the total biogas economically utilised for the medium resource scenario, with and without avoided costs and capital grants.

The proportion of viable biogas energy under different regimes can be considered (Figure 5-9). With both avoided costs and capital grants, on average 87% of the biowaste would be economical for all facility scenarios, decreasing to 51% for capital grants only and 26% for avoided costs only. The grant for 50% of capital costs encourages CHP and REG more than BB, probably due to heat network costs being higher for the Island and Centralised facilities. It also demonstrates the importance of co-locating heat generation with demand (also discussed in Section 7.5.2).

For the Island and Centralised scenarios, transport costs are a bigger factor than avoided costs, with capital grants making more facilities viable. Avoided costs have more impact in the Industrial scenario, combined with the upsides of mixed waste types indicating that industrial facilities could pay less than current waste disposal charges but still economically increase biogas utilisation.

With neither avoided costs or capital grants, only two Industrial scenarios would be feasible, with an average utilisation of 65% (15% counting all scenarios). Whilst this limits how waste could be utilised, it is encouraging that without any capital grants, facilities for BB or CHP could be viable for most industrial sites. With several whisky mainland distilleries having anaerobic digestion facilities already (Ricardo Energy and Environment, 2020), encouraging knowledge sharing of how best to set up, integrate and manage anaerobic digestion and renewable heat systems could improve the deployment of the technology without being limited by capital grants. If the national and local government wishes to maximise the benefits of circular economic principles to reduce waste, reliance on imported fuels, and greenhouse gas emissions, policies supporting the capital-intensive stages of development are critical (Section 8.1.2).

5.7.2 Heat network connection costs

Heat supply not co-located with demand (i.e. all industrial facilities except distilleries), average heat network costs (£923 /MWh) from a range (£410-1496 /MWh) (DECC, 2015). At a minimum, these costs make up 13-47% of CAPEX, which increases to 36-76% at the maximum, which affects the viability of facilities (Figure 5-10). With lesser network capacities required, CHP facilities are minimally affected. As the dispersity of the Scottish islands results in increased network costs, CHP seems preferable in instances where heat networking could be required. BB is more sensitive to heat network costs, making the larger Centralised and Island facilities unviable at the upper end of network costs. More precise estimates of heat network costs would be essential to compare options and analysing the feasibility of specific sites. This also reinforces the importance of financial policy support for this capital-intensive aspect.

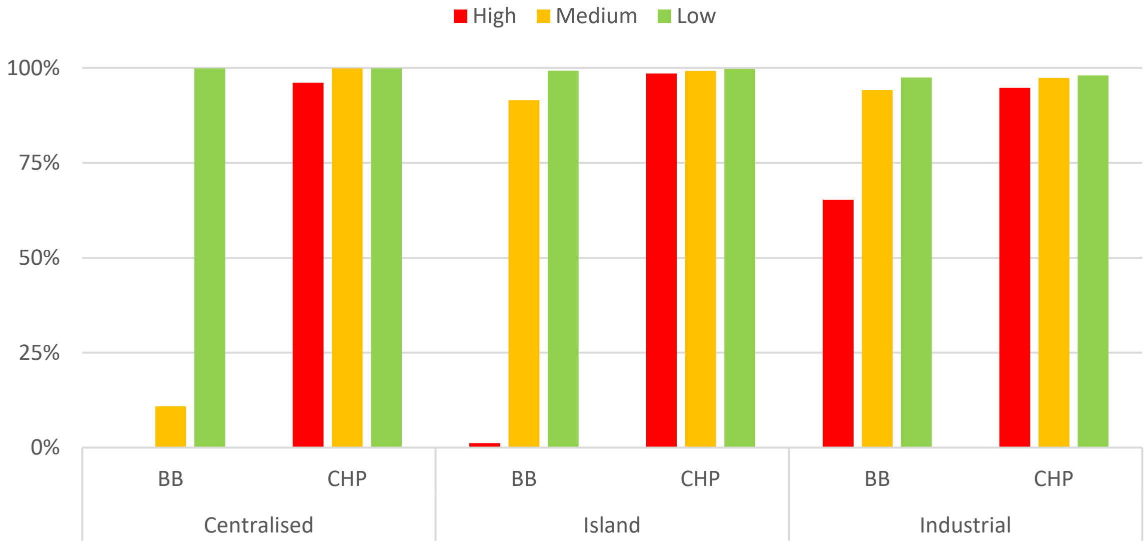

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Figure 5-10: Proportion of viable facilities by scenario considering High to Low heat network costs (£410-1496 /MWh).

5.7.3 Household collection rates

Household participation was identified as the main factor dictating waste collection (WRAP, 2021). This was varied from 30-60% in the resource scenarios (Section 5.1.3), but also separately to understand the economics of policies affecting collection rates. By varying the participation rate, collection costs were calculated to see the effect of increased rates on the collection cost per tonne (Figure 5-11). As they are proportional to distance travelled, fuel costs increase linearly with household participation rate. The increase for ferries is more jagged, with increased participation reducing ferry costs in some cases (80-90% participation) which might have more optimal ferry journeys.

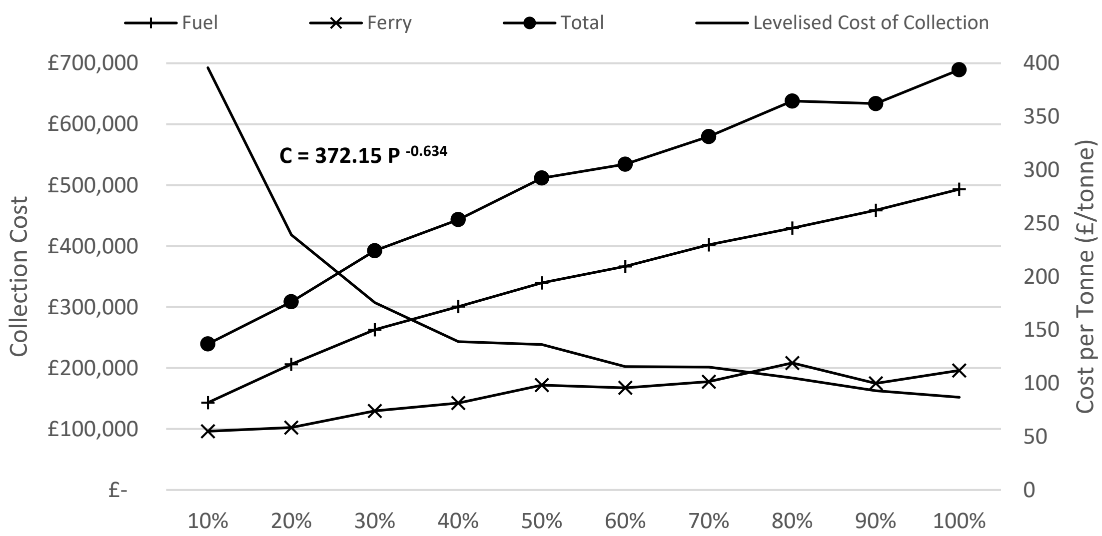

Figure 5-11: Proportion of participating households and food waste collection costs, where the levelised cost of collection per tonne includes CAPEX and OPEX (Matthew and Spataru, 2023b).

A power law (Eq. 5-5 and shown in Figure 5-11) with an R-squared >0.99 is observed looking at the levelised costs of collection - calculated using the same equation as the LCOE with tonnes of waste instead of energy. The constant *k* (372.15) and exponent *α* (-0.634) could be related to the geography of the islands and unit costs. This relationship was not identified elsewhere in the literature for waste collection costs. If it could be related to some feature of local road networks, collection costs estimated based on this relationship would be much faster than specific modelling. Local government would be able to conduct cost-benefit analyses for the costs of greater collection and policies encouraging increased participation rates. More geographic areas would need to be compared to properly understand the consistency of this relationship.

$$C = kP^{\alpha} \qquad \text{Eq. 5-5}$$

C = collection costs (£/tonne); k = constant (£/tonne); P = participation rate (-); α = exponent (-).

5.8 Net Zero model scenarios and policies to achieve them

The results of this biowaste model will be incorporated into the Net Zero model (Chapter 7) through scenarios-based input of the economically viable energy. The main output of this chapter is the LCOE based on resource availability, type, location, collection costs, and facility type. This local, feasible energy potential was an upper limit for each geographic area. From the viable combinations of facility and collection areas, the optimal configuration was chosen based firstly on which options had a LCOE below the alternative costs given in Section 5.4 and secondly on which option had the highest resource utilisation. This results in 78% of the total energy potential being viable (Table 5-6 and Figure 5-12). Biogas boilers were identified as the most suitable technology, so only these are included in the final model. Of the 78% (from Table 5-6) viable energy, scenarios for the overall Net Zero model will utilise 100% for the Independence, 50% in the Middle Way, and 0% in the BAU and Export scenarios (Table 5-6). Which of these scenarios would be feasible will to an extent depend on the level of policy support, which is discussed in the following Section.

Table 5-6: Reiteration of the biogas scenario definitions from Table 3-3.

Scenario	Description	Proportion of biogas utilised
Independence	The maximum economically usable biowaste on the islands, applied to displace industrial heat in the demand model which will minimise local hydrogen demand and need for imports.	100%
BAU, Export	No islands biowaste are utilised to produce biogas - meeting heat demand will be entirely met through local or imported hydrogen depending on the scenario.	0%
Middle	The mid point of the other two scenarios, reflecting less extensive policy support.	50%

Table 5-7: Facility and generation types with the most favourable LCOE for each collection area (see Figure 5-3). Averages are given for the LCOE and resource utilisation; the energy potential is the total.

Collection area	*Facility type*	*LCOE (£/MWh)*	*Annual energy (GWh)*	*Resource utilisation (%)*
Arran	Centralised	121	9.9	100%
Bute	Industrial	291	1.5	100%
Gigha	Industrial	57	1.0	100%
Great Cumbrae	Centralised	121	0.3	100%
Islay and Jura	Island	110	48.3	75%
Lewis and Harris	Industrial	57	11.6	100%
Lismore	Island	235	0.3	100%
Luing	Centralised	99	0.8	71%
Mull	Industrial	89	5.6	99%
Orkney	Industrial	102	12.9	80%
Shetland	Industrial	93	16.0	83%
Skye	Industrial	60	8.2	50%
Small Isles	Island	278	2.0	100%
Uists	Centralised	100	2.4	43%
	Total/mean	103	120.7	78%

Achieving the level of biogas uptake in the Independence scenario would require more ambitious and specific commitment to the sector. Particularly, collection costs in remote areas are high, with rural areas currently exempt from mandatory household food collection (Scottish Government, 2022c). Collection cost modelling highlighted that costs can be significant, but industrial anaerobic digestion could be more cost-effective combined with local waste. Increased participation of households and businesses in biowaste collection reduced modelled collection and energy costs, which could be encouraged through information campaigns. Cooperation between businesses, communities, and local government is needed to maximise this benefit. While this goal is supported in the Net Zero Strategy (UK Government, 2021), specific policies to facilitate it are lacking. Cross-sectoral initiatives are needed, such as the Biomethane Industrial Partnership Europe, a collaboration between countries, industries, academics, feedstock producers, and NGOs (European Commission, 2023b). Grants for capital costs also significantly improved modelled resource utilisation by reducing energy costs. If not provided as direct grants, low-interest loans might support businesses and communities setting up anaerobic digestion and/or generation capacity. The only current support scheme for biogas is limited to projects exporting gas to the grid (DESNZ, 2023a). Providing tariffs for all biogas fuel-switching projects could provide greater emissions savings and improve resource intensity.

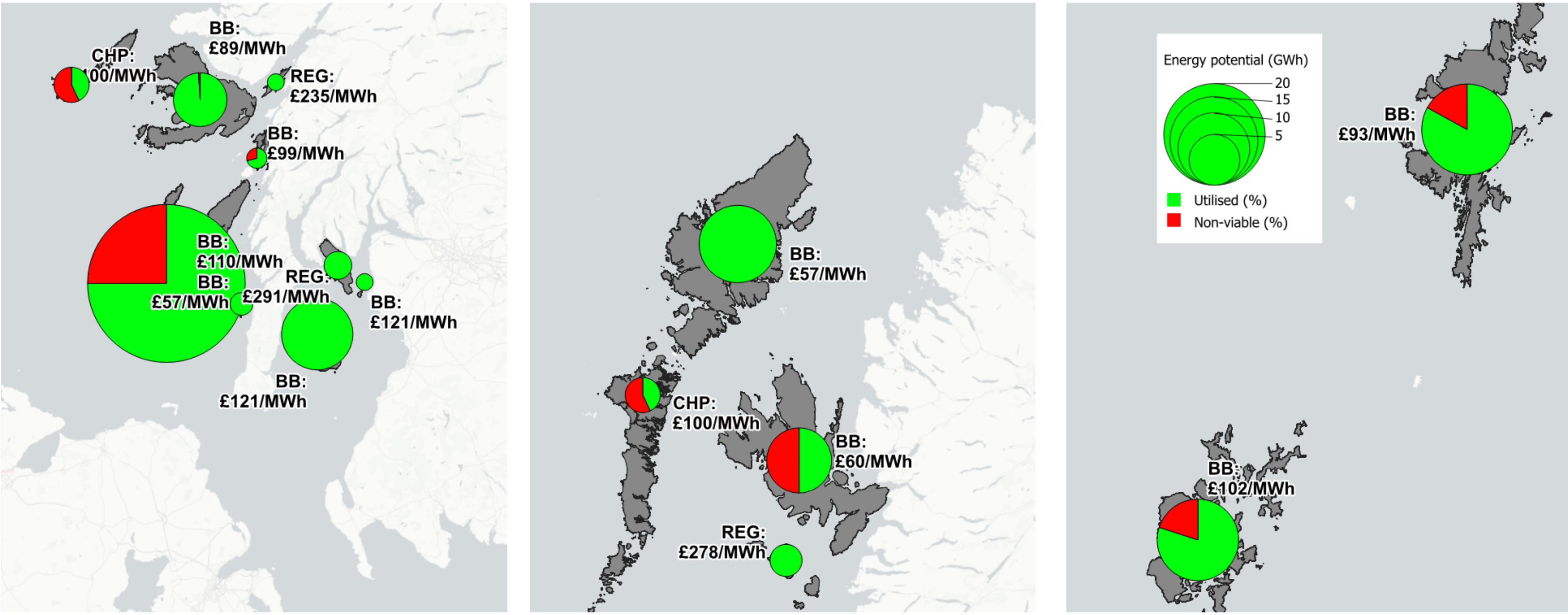

Figure 5-12: The biowaste available in the Independence supply scenario. The label indicates the LCOE (£/MWh) and the type of technology- biogas boiler for heat generation (BB); reciprocating engine generator for electricity (REG); and combined heat and power (CHP).

5.9 Discussion of biowaste potential

The techno-economic modelling of biogas facilities underscores factors influencing their viability: waste availability; waste collection costs; and generation technologies. The potential of biogas to substitute for fossil fuels, as emphasised in the REPowerEU plan (European Commission, 2023b), is corroborated by the model, given the potential contribution 14-21% of the islands electricity demand (BEIS, 2022f). Despite two-thirds of the waste being industrial, regional solutions vary based with waste type, availability, and location. The model highlights the impact of increased resource availability in reducing costs, highlighting the importance of policies which increase participation in biowaste collection. By varying household collection rates, a correlation was shown that could be adjusted for local road networks and used to assess the cost-effectiveness of such policies. Business participation was assumed to be 100%, but this is likely an overestimate. Although resource variability is considered on a scenario basis, interannual variability or high/low years were not, which could significantly affect viability if the facility is underutilised. Further research would be needed to understand this aspect. While intra-annual variability is not factored in, biogas could be stored at a cost to better align supply with demand. Overall, the results show that maximising the participation of households and businesses can reduce the cost of energy, so policies enabling this should be supported.

Modelling actual road networks allows the cost of energy to be understood in a way which would not be captured by a more straightforward cost-per-tonne metric. Calculated in these terms, they range from £0.1 up to £1670 per tonne. The cheapest of these occurs in the distillery-dense Islay and Jura, where a 5km stretch of road has 22% of the whole islands whisky production capacity. The highest are for food waste collection for the Small isles, which have populations of 83, 27, 22, 12, and 9 in the last census (National Records of Scotland, 2016) and are only accessible by ferry. For more populated but spread out, ferry-connected regions, there is a slight reduction in vehicle costs per tonne with greater resource availability. However, for larger islands without ferry connections, the cost reduction is more pronounced. The smallest and most remote areas would struggle to establish economically viable facilities, given their comparatively higher collection costs. Within the modelled framework, isolated communities might miss out opportunities to reduce emissions with biowaste unless supported by additional capital grants or other similar financial policies. Alternatively, smaller-scale, customised solutions tailored for the local context not accounted for in this analysis could be more practical.

For nearly half (17 out of 36) of the scenarios, the most economical biogas potential revolved around industry. This makes up 85-97% by energy potential, primarily from distilleries which have notable heat demands, eliminating collection costs. For 39% of these industrial-centric cases, the cost of energy could be reduced by excluding non-industrial waste, but in 36% the cost of energy was greater including non-industrial waste and collection costs. For those regions with lower industrial potential (26-73% of potential energy), centralised facilities collecting all waste types were the most economically viable. This mirrors the integrated approach of the OHLEH (Section 1.2) and underscores the unsuitability of a "one-size-fits-all" approach in waste-to-energy modelling, with the optimal solution depending on local conditions.

The model considered both avoided costs (existing waste collection costs) and grants for 50% of capital costs. Sensitivity analysis of economic viability showed that capital grants played the greatest role in increasing biowaste utilisation, suggesting that up-front capital costs could be a barrier to development of biogas capacity that policy should target. This grant level was based on the since closed Low Carbon Infrastructure Transition Programme, which had several rounds of funding for up to 50% of capital costs for various emissions reducing projects (Scottish Government, 2021d).

The major UK-wide policy for anaerobic digestion and biogas is the Green Gas Support Scheme, but it only provides a tariff for biomethane injected into the gas grid, so would not encourage Scottish island or other off-grid capacity (CCC, 2023). Previous renewable heat policies (domestic and non-domestic RHI) are now closed with no signs of renewal. The only policy identified that could be relevant to the islands in the most recent UK-wide biomass strategy is the now closed Biomass Feedstocks Innovation Programme, which funded research into feedstocks. Otherwise, the report only commits to developing further plans (DESNZ, 2023a). The most recent update in 2021 to the Scottish-specific plans makes no reference to further policies, and the update due for 2023 has yet to be released (Scottish Government, 2021a). With the closure of the RHI, specific policy support for anaerobic digestion and biogas for locations off the gas grid are inadequate to encourage any growth in the sector. Whether they materialise in subsequent sectoral plans for the biomass sector remains to be seen. However, if fossil fuels are phased out, to be replaced with likely more expensive hydrogen substitutes, this could increase the attractiveness of biogas - this is discussed in the context of the overall Net Zero model results in Section 8.

The Biogas model could be enhanced with a more detailed anaerobic digestion model. Previous research has indicated that co-digestion can enhance biogas yields (Bong *et al.*, 2018; Karki *et al.*, 2021; Zhang *et al.*, 2022). If feasible, this could further diminish the cost of energy with multiple waste streams. As highlighted in other work (Karki *et al.*, 2021), further investigation into the dynamics of co-digestion is warranted to better understand the synergies between specific waste sectors. It is not clear what effect the assumed two-week collection period would have on biogas yields. Calculation of detailed transport costs to demonstrate the economic feasibility of co-digestion (particularly if industrial biogas costs can be reduced by additional waste streams) underscores the significance of co-digestion. In the modelled cases (assuming no enhanced biogas yields) co-digestion can already reduce energy costs, the impact would be more pronounced with increased co-digestion yields. Quantifying the theoretical and practical benefits of co-digestion for specific waste types through further research could help minimise regulatory barriers and encourage collaboration among waste producers. A governmental organization could facilitate this process by sharing best practices and providing a platform for SMEs, farmers, household waste collectors, and industries to collaborate, thereby maximizing the advantages of waste-to-energy. Despite the sensitivity analysis highlighting the crucial role of capital grants in supporting schemes, especially in isolated regions, the potential utilisation of 51% of resources without such incentives indicates that solely economic factors should not limit the adoption of waste-to-energy.

To concentrate on waste-to-energy and streamline scenarios, this analysis has exclusively considered anaerobic digestion and three generation technologies (BB, CHP, REG). It could also be broadened to encompass a more extensive resource nexus framework (Bleischwitz *et al.*, 2017). The exclusive focus on the energy-materials nexus omits water, land use, and food impacts (although this has been minimised per Section 5.5); areas where there could be substantial consequences which are not addressed in this study (Spataru, 2019). Additionally, expanding the geographic coverage may enhance the reliability of conclusions, but necessitate substantial additional data collection and computation.

6 Characterising generation, networks, and flexibility

Generation and electricity network characteristics are required for the Net Zero model as inputs to PLEXOS. Firstly, to demonstrate that PLEXOS can capture the techno-economic characteristics of the UK's electricity generation system, the model has been validated using recorded demand and supply data. Modelled results are compared with actual generator dispatch and prices to give confidence in using the PLEXOS model to make projections. 2017/18 was chosen as the most recent year of available data at the time of the analysis in 2020. Following this, the scenarios of generation, networks, electrolysis, and flexibility for the Net Zero model (summarised in Chapter 3) are each described in detail.

The differences between the validation and Net Zero supply model are summarised in Table 6-1. The main outputs of this section for the Net Zero model for each node are scenarios of generator capacities, hourly renewable capacity factors, network constraints, and flexibility capacities.

Table 6-1: Summary of the main differences between supply and interconnection models.

Aspect	*Validation model*	*Net zero model*
Nodes	14 mainland (one per DNO); 7 island	1 mainland; 30 island
Generation	2017/18 capacity	Mainland: FES 2045 capacities, Islands: scenarios-based
Network	2017/18 data	Network shapefiles plus scenarios
Demand	Recorded 2017/18 data	Demand model (Chapter 4)
Electrolysis/ Flexibility	None	Capacity by scenarios
Scenarios	None	Four island scenarios
Purpose	Validation of Electricity Market section of Net Zero model	Optimisation of net zero energy system for the islands and mainland

Whereas the Net Zero model combines Electricity and Gas (hydrogen/biogas) Markets in PLEXOS (market being the model structure used to represent the dispatch of each energy type), the validation model only covers the Electricity Market. This allows the resulting electricity dispatch to be compared and validated with demand data from every DNO for 2017/18. The optimisation process for both models uses the same equations (described in Section 3.2.1) and methodology to determine technology techno-economic characteristics and network constraints. While these aspects used the same underlying datasets, they are varied depending on the year modelled. For the islands, the Renewable energy planning database (REPD) (BEIS, 2022d) and FiT sub-regional (BEIS, 2020d) databases have been used to assign existing (both models) and planned (Net Zero model only, by scenarios described in Section 3.5) generation capacities to each node. The validation model uses historic generation capacity (DESNZ, 2023d) whilst the Net Zero model projects for generation, BESS, DSR, and electrolysis (National Grid, 2023).

As discussed in Section 3.4.5, available computing power is a limiting factor when considering the resolution of PLEXOS. In both this validation and the final Net Zero models, the Scottish island have been modelled in greater geographic resolution. For the validation model, with demand data available for DNO regions and a simpler optimisation process, it was possible to model each of the 14 mainland UK DNO regions. Including transmission constraints will further improve the accuracy of the model and should reduce this potential cause for error in the validation results.

In the Net Zero model however, run-times were significantly longer with more mainland nodes, particularly due to having eight scenarios. Therefore, it was decided to simplify the mainland as a single node. While this may reduce the accuracy of the mainland representation, given one of the main aspects required for modelling net zero on the islands is the availability of electricity imports, the overall effect on the results should be limited. Between island nodes, existing network limits have been estimated based on network shapefiles (SSEN, 2019). In the validation model, the existing network capacity has been used (National Grid, 2018). Grid constraints on the mainland UK are not considered in the Net Zero model - implications of this on results are discussed in Section 8.5.2.

The novelty of the work presented in this chapter consists of the following:

- *(i)* *Constraints on land use:* GIS shapefiles from local authorities' local development plan (LDP) are used to constrain the land areas for potential development, meaning scenarios are within the development limits for each node.
- *(ii)* *High resolution modelling of wind and marine:* Renewables Ninja and recorded tidal current data is used to calculate nodal capacity factors, representing the energy production for different time periods and capturing the effects of geographic diversity.

6.1 Supply and interconnections for all models

The data and methodologies outlined in this section are used for the supply validation and Net Zero models. Aspects which differ are described in subsequent sections.

6.1.1 Techno-economic characteristics

Techno-economic characteristics for each generation type are as much as possible selected from the same source (BEIS, 2020b). Where the required characteristics for renewable and thermal generation (Appendix B.2) were not readily available, a separate reference is given. Hydrogen generation was included for the Net Zero model (2045), but not the validation model. Coal is not included in the Net Zero model.

Although gas with CCUS and BECCS are different technologies, they have been modelled with the same techno-economic characteristics apart from additional CCUS cost. These have been calculated based on the previous emissions factors and CCUS costs of £23 /tonne (BEIS, 2018a). There will be significant uncertainty in this value, but similarly to the description of the assumptions used for omission of subsidies (Section 3.4.4) this is unlikely to change the merit order which is the main aspect that the mainland model needs to capture.

Additional characteristics used for electrolysis, DSR, and heat as used in the final PLEXOS model are detailed in Appendix B.2.

6.1.2 Estimating renewable generation production

For all wind and solar PV capacity factors, the Renewables Ninja API was used (Pfenninger and Staffell, 2019). This service uses locations, technology types, generator capacities and a period to calculate hourly capacity factors using NASA and EUMETSTAT reanalysis databases. These hourly inputs are then used as PLEXOS inputs. The results from this were validated for 2017/18 by comparing with recorded generation data (Section 6.2).

For tidal current, data for a site off Orkney was sourced from EMEC under academic license (EMEC, 2019b). As the islands all have a semi-diurnal tidal pattern (Neill *et al.*, 2017), the data for Orkney was approximated for each tidal current device location using peak velocities and high/low tide timings (Tide Times, 2019). A power curve was used to convert tidal stream velocities into a capacity factor (Hardisty, 2012). For all renewable generation, capacity factors were collected for specific generators and then averaged for each nodal area in both the validation (Section 6.2) and final model (Section 7).

6.1.3 Capturing interconnection and network constraints

The thermal limit of network constraints between mainland DNO regions (only considered in the validation model) were available directly (National Grid, 2018). For the islands, whilst line locations and physical characteristics were available, this did not include data on line thermal limits, which was approximated using network shapefiles (SSEN, 2019). Network line dimensions, material of construction, voltage, and number of cores was combined with Eq. 6-1 (Reta-Hernández, 2018) to calculate the thermal limit. The equation gives the energy balance in a transmission line, where the heat generated in a conductor (left side of Eq. 6-1) is dissipated by radiation and conduction (right side).

$$VI = S(w_c + w_r) \qquad \text{Eq. 6-1}$$

V = voltage (V); I = current (A); S = surface area (mm^2); w_c = convection heat loss (W/mm^2); w_r = radiation heat loss (W/mm^2).

By substituting in equations Eq. 6-2 for radiative and Eq. 6-3 for conductive heat losses (with the resistance known based on the conductor material) in Eq. 6-1, the current could be calculated. Based on the standard calculation of line thermal limits, values given below each equation were assumed (IEEE, 2013) to calculate the power capacity of each line in the network shapefiles. Values for several known capacity limits (Orkney, Lewis and Harris, and Mull) were compared as a sense check.

$$w_c = \frac{0.0128\sqrt{pv}}{{T_{air}}^{0.123}\sqrt{d_{cond}}}\Delta t \qquad \text{Eq. 6-2}$$

p = atmospheric pressure (101.3 kPa); v = wind velocity (0.5 m/s); d_{cond} = conductor diameter (mm); T_{air} = air temperature (308 K); Δt = conductor temperature change (45 K).

$$w_r = 36.8E\left(\left(\frac{T_c}{1000}\right)^4 + \left(\frac{T_{air}}{1000}\right)^4\right) \qquad \textit{Eq. } 6\text{-}3$$

E = emissivity constant (0.5); T_c = conductor temperature (353 K); T_{air} = air temperature (308 K).

In the Net Zero model, planned and existing mainland lines are considered. Interconnections currently connect all occupied islands (except Shetland, which has a separate network) to the UK mainland electricity system at a capacity sized to meet local demand, but not to cover the significant export of electricity, which has constrained development of local generation (Orkney Renewable Energy Forum, 2014). Further planned or under construction interconnections have also been included based on plans for Orkney, Shetland, and Na h-Eileanan Siar (SSEN, 2023b) This is discussed in more detail in Section 6.5.3.

6.2 Validation of the supply and interconnections model

The supply and interconnections model were validated in PLEXOS using data from April 2017 to April 2018, as the most recent year of available data at the time of the analysis in 2020. The purpose of this validation step is to demonstrate that the supply and interconnections model captures the essential behaviour of these technologies in an energy systems context. For renewable generation (Section 6.1.2), this means the timing of generation is correlated with weather patterns that influence demand (Section 4.2.6) and the spatial correlation of generation across the UK. For generation systems, it also means that the merit order of dispatch considers the interaction between generation and demand, affecting the import and export of electricity to the islands in the Net Zero model. This can be assessed by comparing the electricity price with actual prices. It is not intended that the error between the validation model and recorded data be minimised as much as possible when there is no way of knowing whether the same characteristics would have any bearing on projecting system behaviour in 2045. Rather than overfitting the model to current data and assumptions (Section 3.3) which might not hold in 20 years time, capturing the simplified aspects of electricity generation is sufficient for the purposes of modelling net zero for the islands.

DNOs were contacted to provide historic demand data: Electricity Northwest (ENW, 2019), UK Power Networks (UKPN, 2019), Northern Power Grid (NPG, 2019), Western Power Distribution (WPD, 2019), and Scottish Power Energy Network (SPEN, 2019). The local, GSP-level demand for all other DNO's did not include transmission losses, so it was scaled to match BEIS annual generation totals (DESNZ, 2023d). Scottish and Southern Electricity Networks (SSEN), who serve Southern England and Northern Scotland (including the islands), were initially contacted in the spring of 2020 but were unable to provide demand data. The GSP demand data which was used to validate the demand model (Section 4.5) was acquired at cost after negotiation later in the autumn of 2021, so was not available at this early stage of the analysis. Demand for the two SSEN regions was instead approximated using daily and annual maximum and minimum demand profiles from the Long Term Development Statement (LTDS) (SSEN, 2020c). The average daily demand curve (left side of Figure 6-1) being applied to the daily min/max curves for each day of the year (right side of Figure 6-1).

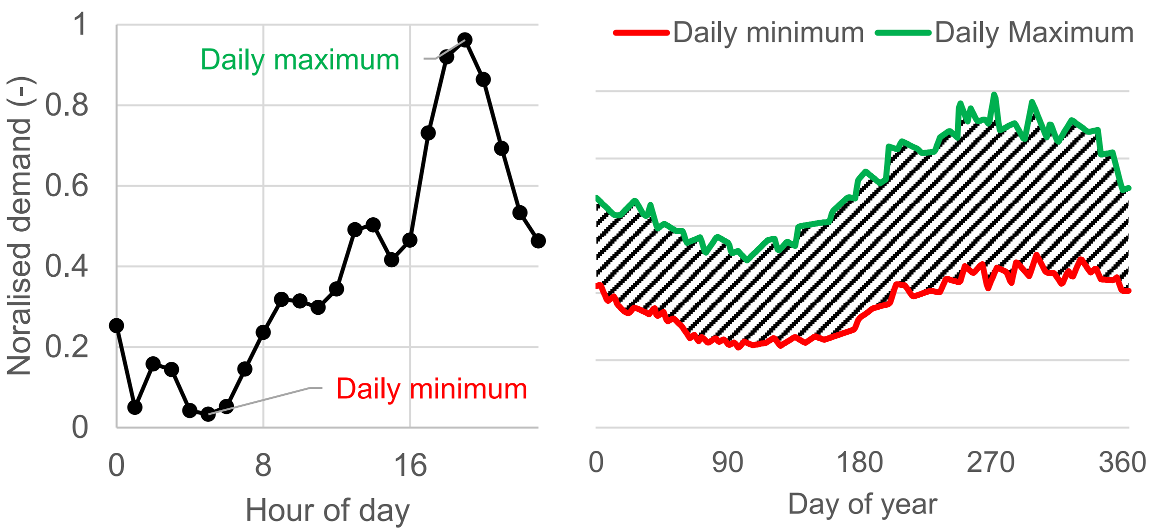

Figure 6-1: Representation of the method used to approximate SSEN demand from the LTDS, with the average daily demand curve (left) applied to the daily maximum and minimum daily demand for each day of the year (right) (SSEN, 2020c)

Generator data was included for the same year from DUKES for thermal generation (DESNZ, 2023d) and REPD for renewables (BEIS, 2022d) (Figure 6-2). National Grid transmission constraint data was used for the rest of the UK (National Grid, 2018).

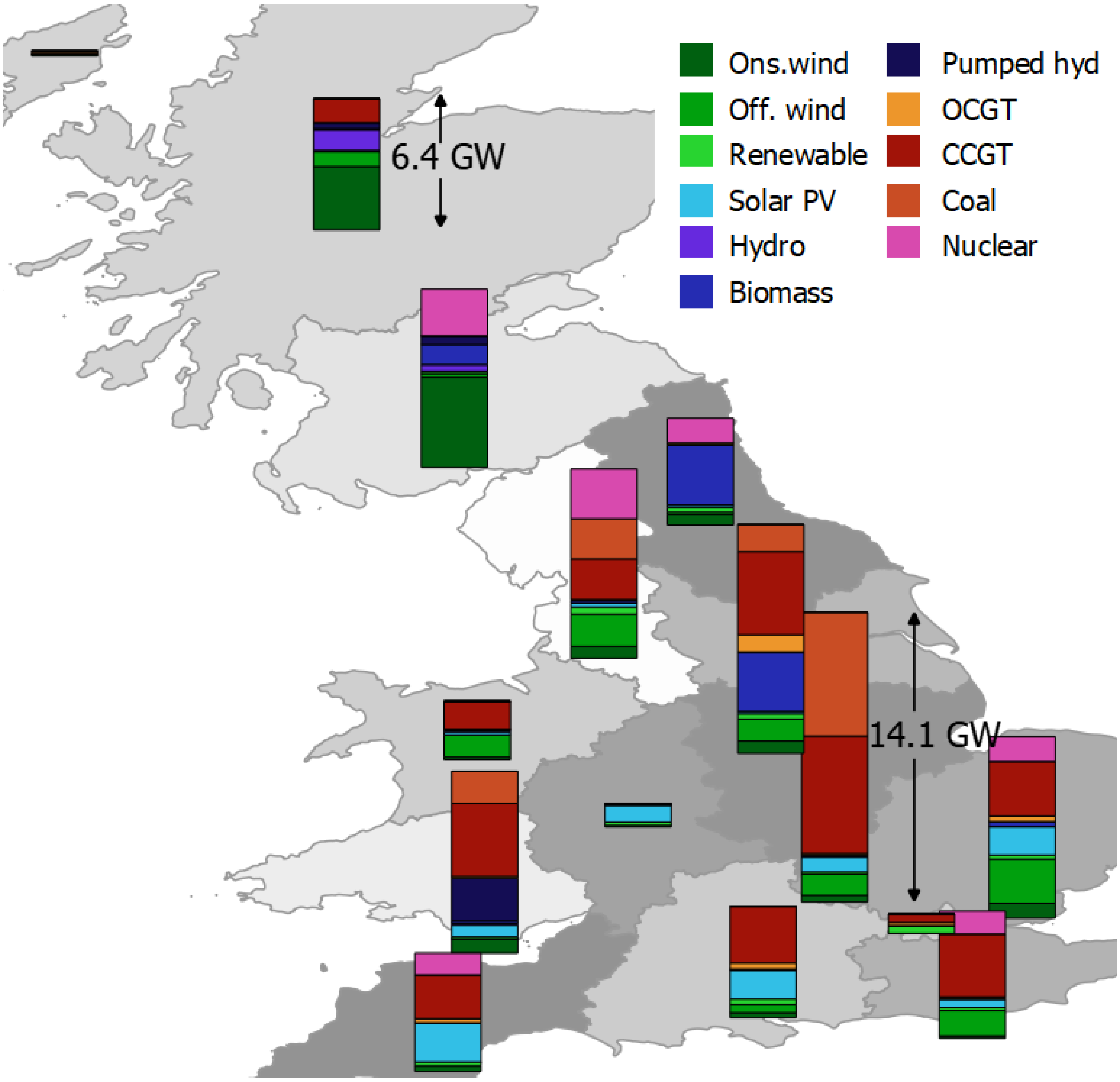

Figure 6-2: Renewable (BEIS, 2022d) *and thermal* (DESNZ, 2023d) *generation capacity for each node/DNO of the validation model (2017/18). Island capacity has been grouped for Lewis and Harris in the top left (0.25 GW total).*

The validation model incorporated renewable subsidies of CfDs, FiTs, and ROCs (Low Carbon Contracts Company, 2023). These were approximated as a capacity-averaged single payment band in £/MWh for biomass, wind, solar, wave, and tidal. Balancing (National Grid, 2019c) and transmission (National Grid, 2019a) use of system charges were also included for each DNO region. These were not applied to the final model for the reasons discussed in Section 3.4.4.

6.2.1 Comparison with recorded generator dispatch

The annual modelled generation by generator type can be compared with recorded data (DESNZ, 2023d) (Figure 6-3). This demonstrates that the model captures the merit order of dispatch and total generation of each to within ±13%. The overprediction of gas and underprediction of coal, nuclear, and biomass is likely due to the model only considering the spot electricity market and not any forward contracts that nuclear or biomass could have. The under-generation of coal could be due to other market structures, carbon pricing, or startup costs. Without coal in the Net Zero model however and nuclear/biomass (with CCUS in 2045) functioning as baseload, the effect on the resulting generation and surplus available to be exported to the islands is likely minimal. Overall, the balance of energy generated by source is captured by the model to the extent that is required for modelling interconnection flows with the islands as the focus of the study.

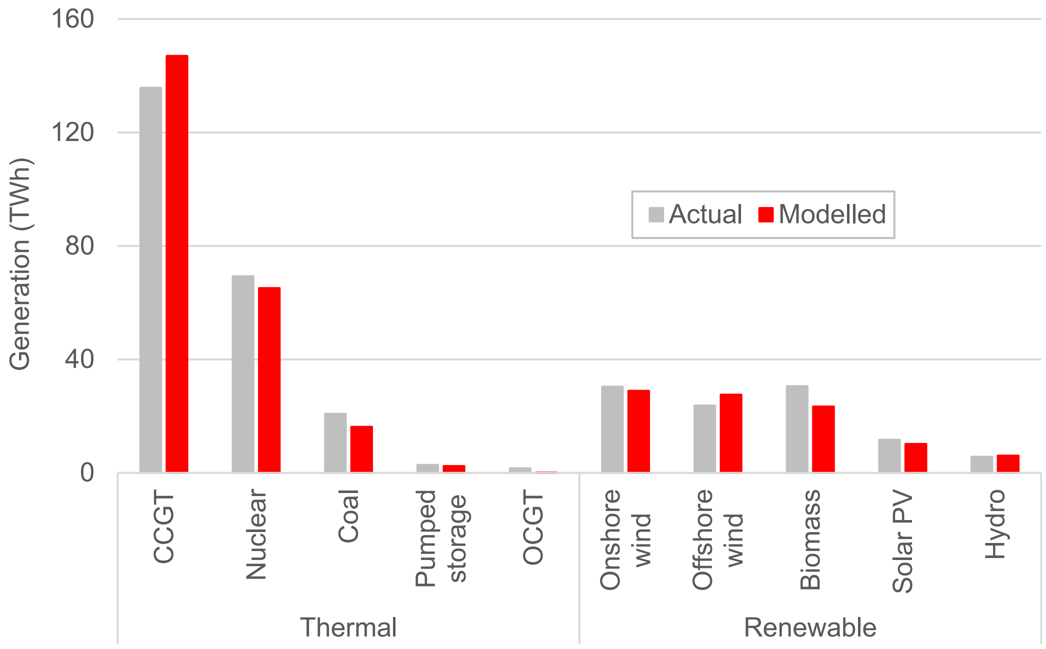

Figure 6-3: Comparison of actual and modelled annual generation data (Matthew and Spataru, 2021).

The capacity factor model for wind is compared with hourly generation data (Elexon, 2019) and is shown for a single month in 2017 (Figure 6-4). The model captures the temporal variability of generation with a RMSE of 0.85 GW, but over-estimates peak generation. As in other analyses using the Renewables Ninja API (Staffell and Pfenninger, 2016), a correction factor was applied, but this has failed to correct the over-estimation of peak generation entirely. This could be due to using idealised power curves for different wind turbines. The factor was also calibrated using BEIS statistics, which may differ in reporting methodologies from the hourly Elexon data used here. As the model error is much less significant for periods of minimum generation, peak renewable generation error should have minimal impact on the winter (high demand, low supply) period of extreme weather modelled in the Net Zero model (Section 3.4.5). Over-estimation of peak generation could however exaggerate generation during the summer (low demand, high generation) scenarios, the implications of which are discussed in Section 8.5.2.

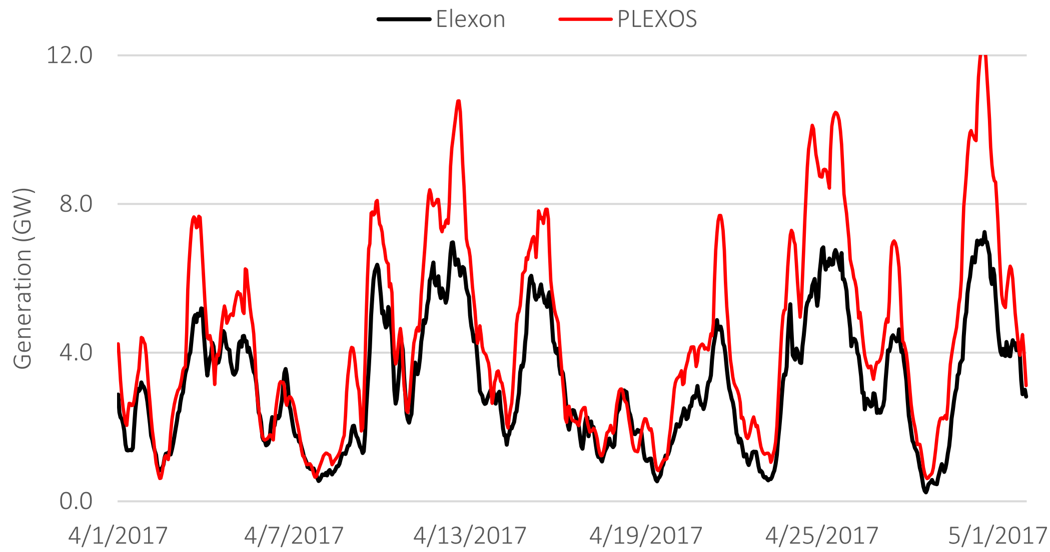

Figure 6-4: A representative month of national wind generation compared with recorded data (Matthew and Spataru, 2021).

To further interrogate the wind capacity factor model given wind is anticipated to be the most significant UK renewable generation in 2045, the spatial correlation of the model was also compared by looking at the Pearson correlation factor of hourly nodal generation and the distance between nodes. Modelled data has been compared with analysis of 2,080 actual wind farm locations across the UK (Figure 6-5). As the modelled data is for generation aggregated by node for multiple generators (whereas the trendline is for individual sites), difference in generation due to weather patterns is averaged out and the modelled correlation is exaggerated for the closer nodes. This difference decreases as the distance between nodes increases, indicating that the modelled capacity factors capture spatial weather patterns which would affect weather-based correlations in demand and generation for the Net Zero model.

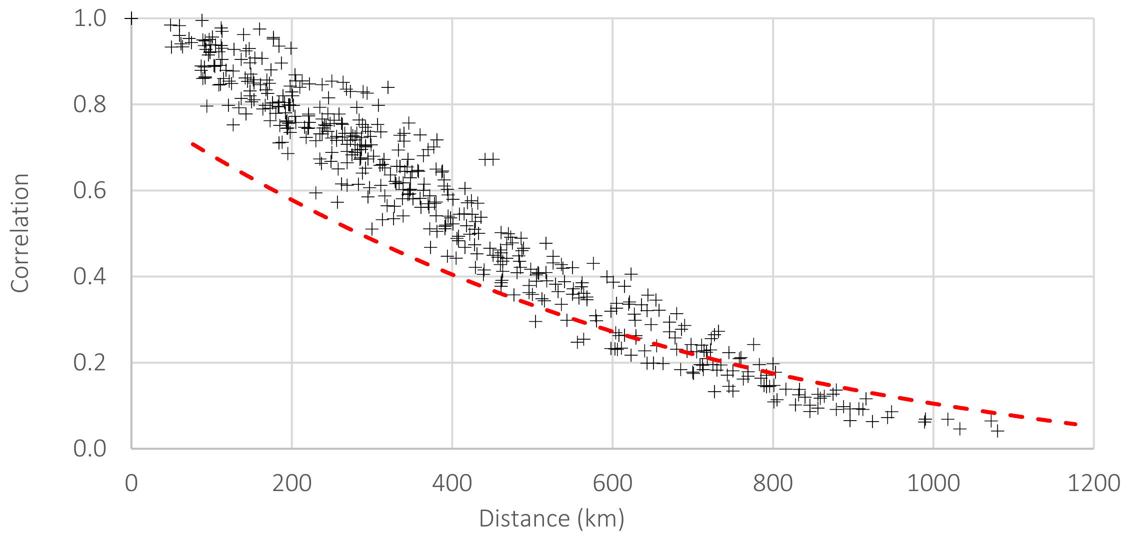

Figure 6-5: Correlation coefficient between modelled nodes, with the trendline from recorded correlation for wind farms across the UK (Matthew and Spataru, 2021).

6.2.2 Comparison of modelled electricity prices

Comparison of the modelled electricity price and recorded prices shows that the model does a good job capturing the average daily variation with demand, but not the absolute value (Figure 6-6). Due to resulting in much longer run-times (several days versus than less than a day), long-run marginal costs (or fixed costs such as insurance, financial costs, generator fixed costs, etc.) were not included in the model optimisation. These were considered as an average uplift to the price, which improved the model significantly, with a MAPE of 3.5%. This captures the key aspect of the merit order of dispatch needed to model net zero on the islands - as demand increases, more expensive generators are used to meet demand, increasing the price of electricity.

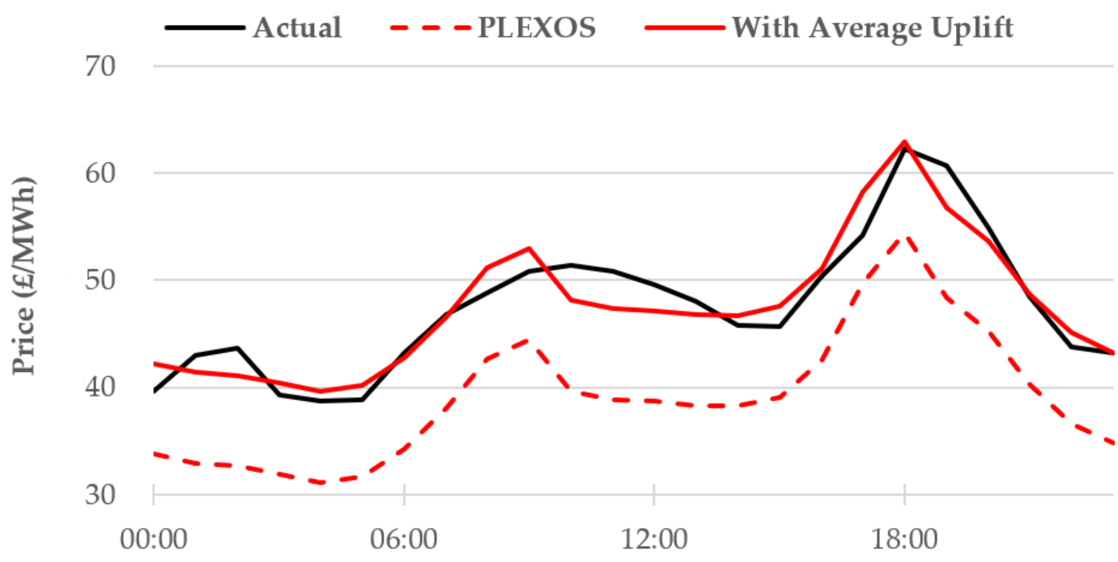

Figure 6-6: Average daily hourly electricity prices compared with recorded, with an average uplift included to reflect long-run marginal costs (Matthew and Spataru, 2021).

Monthly averaged electricity prices are also more representative with the same uplift applied (Figure 6-7). Between September and February, the model has a MAPE of 2.6%, however in the Spring and Summer months, the error increases to 18.8%. Overall demand in the summer/spring months and the winter/autumn varies by 22%. It may be possible that similarly sized perturbations (e.g. forecast errors, unplanned outages, etc.) in the summer/spring have a much larger effect on the average electricity prices, demonstrated by the much larger variability in these months. With further investigation of events affecting electricity prices in the period, the root cause of the discrepancy with the model might be better identified. However, given the model captures seasonal variation in electricity price caused by changes in demand, it adequately captures the mainland UK behaviour needed to model the islands.

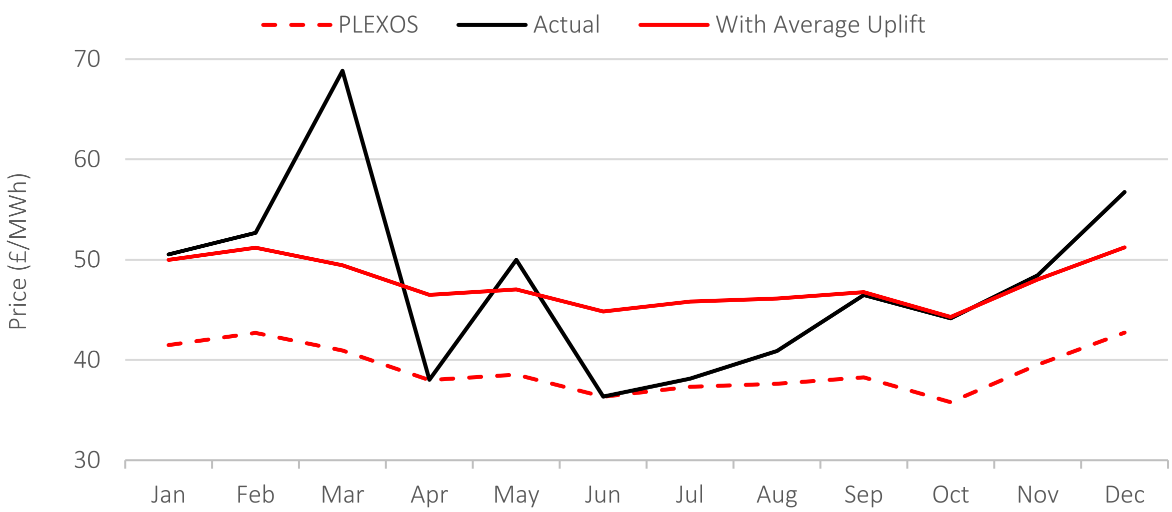

Figure 6-7: Average monthly electricity prices, with an average uplift also included to reflect long-run marginal costs (Matthew and Spataru, 2021).

6.3 Mainland supply, electrolysis, flexibility in the Net Zero model

The mainland has been modelled in more detail in the validation model to incorporate the effects of transmission constraints which could affect calculated generation. For the Net Zero model however, additional computational complexity made similar modelling infeasible. From the perspective of net zero on the islands, the main aspect related to mainland interconnections is the weather effects which influence renewable generation/demand, and so the price of imported electricity. This can be summarised (in addition to demand - Section 4.4) as variability of renewable generation, the merit order of dispatch, and electrolysis operation. As described in Section 3.4.5, interconnections with mainland Europe have not been modelled due to the additional complexity and focus on the Scottish islands. Electricity is the only export from the mainland to the islands requiring hourly balancing, therefore for simplicity, mainland hydrogen demand, heat, and DSR capacity were excluded. Hydrogen is modelled as a cost input (as described in Section 3.4.2, with results in Section 7.5.4); there is no scope to transport heat to the islands; and DSR is already included in the estimates of peak demand made by National Grid used for the mainland demand (Section 4.4). Electrolysis would affect electricity balancing so has been included (Section 6.3.1).

The average of the two highs and lows of capacity of 112.9 GW in Consumer Transformation and 100.8 GW in System Transformation (National Grid, 2023) (Figure 6-8) have been modelled. The FES contains data for the generation capacity of each GSP area, but as the mainland would be treated as a single node without considering transmission constraints, this has only been used for the calculation of capacity factors for onshore wind, offshore wind, and solar PV.

Wind and solar PV capacity factors were calculated per the island methodology (Section 6.1.2). To calculate the hourly capacity factors, onshore wind and solar PV capacity were assigned to DNO regions with FES data, while offshore wind was grouped by offshore region using maps of current and projected future capacity (Figure 6-9) (BEIS and The Crown Estate, 2022; Crown Estate Scotland, 2022). For offshore wind, assuming the same predicted locations, capacity was adjusted to match the totals given in the FES. The Renewables Ninja API was used to extract capacity factors for each of the points in Figure 6-9 over the extreme weather periods (Section 6.4.2). These were then averaged by the capacity of each point to give an averaged capacity factor for onshore wind, offshore wind, and solar PV for the Net Zero model.

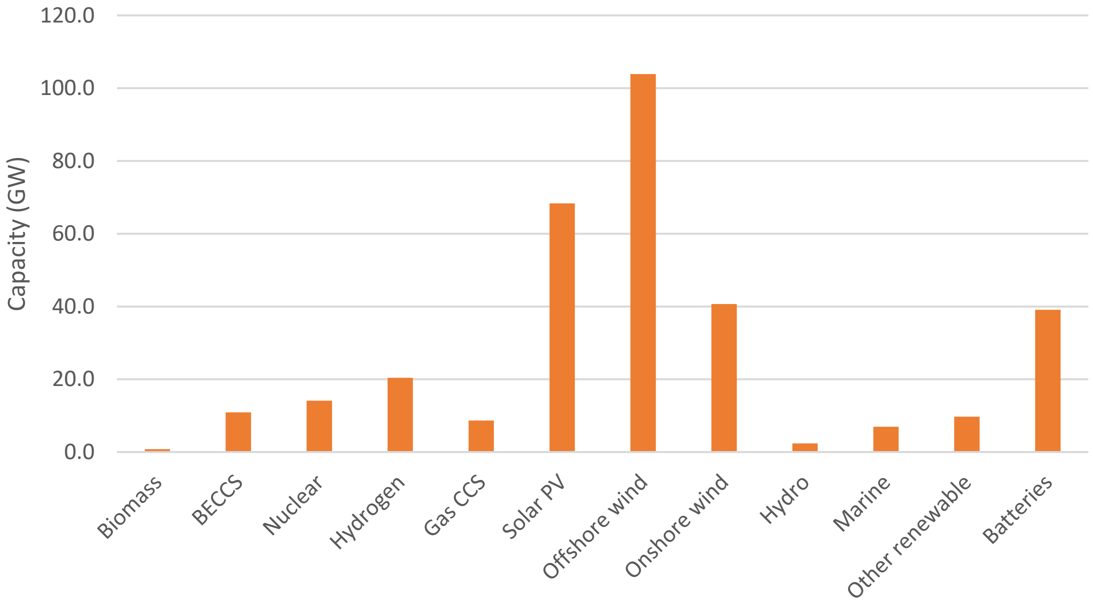

Figure 6-8: Modelled mainland generation capacity, taken from the FES (National Grid, 2023).

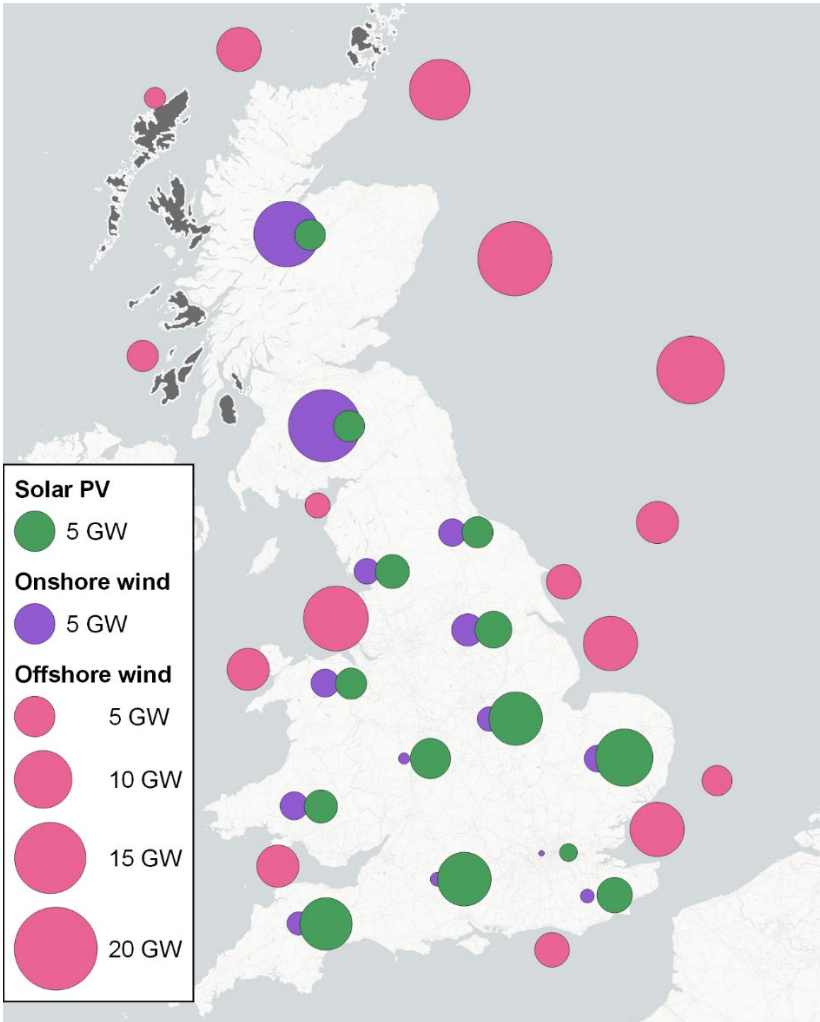

Figure 6-9: Modelled mainland wind and solar PV generation from the FES (National Grid, 2023) *and Crown Estate offshore wind* (BEIS and The Crown Estate, 2022; Crown Estate Scotland, 2022).

6.3.1 Mainland merit order of dispatch

Using the techno-economic characteristics in Appendix B.4 and the previous capacities, the merit order of dispatch can be analysed (Figure 6-10). Baseload is provided by nuclear, BECCS and other renewables (including tidal current, hence the diurnal wave in the orange band). Wind (blue) and solar PV (purple - noting the winter month, hence low solar generation) operate as much as possible. When there is excess generation, the electrolysis (the black hatched area) will operate to produce hydrogen (as controlled in PLEXOS by the prices set in Section 3.4.2) - essentially, the black line shows demand without electrolysis. This results in greater demand (up to the 24 GW of mainland UK electrolysis capacity) both during the day and overnight on the lefthand side of Figure 6-10.

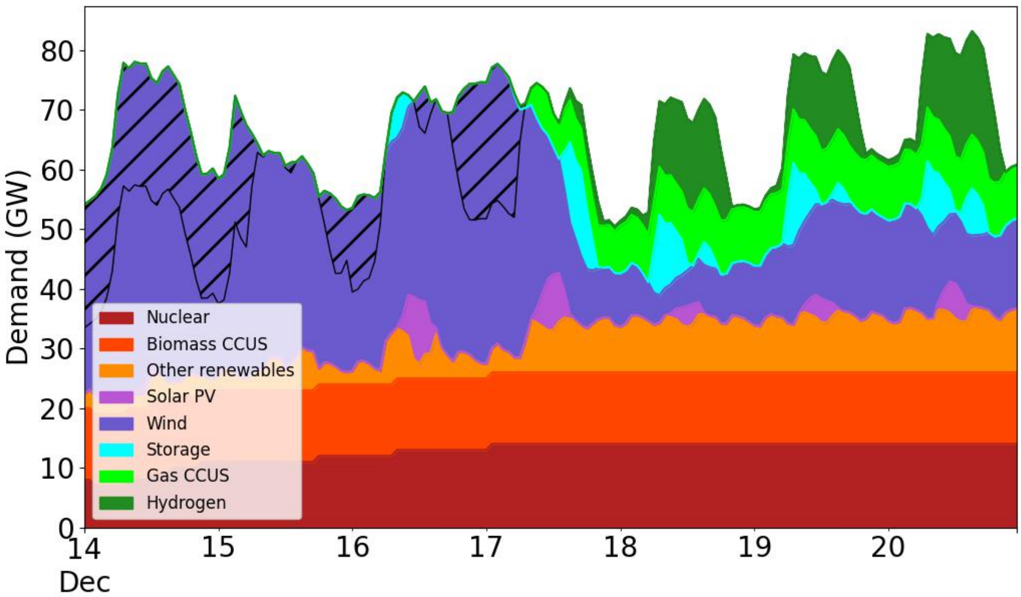

Figure 6-10: Representative week of generation for the mainland in the winter scenario, where the hatched area represents electrolysis demand from otherwise curtailed wind generation. This mainland generation is the same for all island scenarios.

When there is not enough renewable generation to meet or exceed demand (the righthand side of Figure 6-10), then BESS, gas CCUS, or hydrogen generation is required. The modelled BESS can operate for short periods at peak demand only, reducing the need for the more expensive hydrogen generation in the model. Gas and hydrogen are last as the most expensive. It was assumed that gas CCUS would operate first, followed by hydrogen, but in reality this would depend on the LCOE of each, which is highly sensitive to the cost of CCUS and hydrogen as a fuel. If the hydrogen is blue (i.e. produced from fossil fuels), essentially the difference would be whether it is cheaper to store the CO_2 before or after it is combusted for generation. If the hydrogen is green (i.e. produced from renewable energy), the cost will depend more on the cost of electrolysis and electricity. Modelling of hydrogen costs have shown this to vary significantly depending on the configuration, assumed capacity factors, and availability of electricity (BEIS, 2021a). Again in either case, as the prices of hydrogen or gas CCUS are greater than renewables, the main aspect captured for modelling the islands is when wind is price-setting and reflecting what the net electricity transfer would be.

6.4 Supply, network, flexibility, and electrolysis scenarios for the Net Zero model

This section will outline the scenarios used in the Net Zero model for supply, networks, flexibility, and electrolysis. The logic outlined for the whole model (Section 3.5) will be expanded here and how assumptions are used to convert the scenarios into model inputs described.

Scenarios for these aspects are designed to compare two ranges of potential net zero technology configurations (summarised in Table 6-2). The first, for the BAU and Export scenarios, considers that the islands undergo more limited renewable development focusing on smaller-scale capacity and host BESS, DSR, and electrolysis capacity to enable greater energy independence, while reducing the need to upgrade local networks. The second, for the Independence scenario, assumes a greater expansion of large-scale renewable capacity, along with the requisite network upgrades, but considers only BESS, DSR, and electrolysis on the mainland, with all hydrogen being imported. The third Middle scenario not shown in Table 6-2 considers an average of the two. The BAU/ Export scenario is essentially considered a continuation of the Government's policy commitment (discussed in Section 2.5), whereas Independence represents a different direction, with greater emphasis on small-scale, dispersed technologies.

Table 6-2: Summary of the scenarios for each aspect - the Middle scenario is in all cases an average of both capacities.

	Independence	*BAU/Export*
Supply	Limited expansion of island renewables; more household kW-scale generation	Greater expansion of larger, transmission-scale island renewables
Network	No network upgrades required except planned	Networks are upgraded to accommodate more renewables
Flexibility	Distributed BESS and DSR on the islands	BESS and DSR only modelled for the mainland
Electrolysis	Local electrolysis is used to produce hydrogen, either to meet local demand or for export	All hydrogen is imported to the islands

6.4.1 Supply scenarios

Generation in the final model has been treated differently to the validation model. Scenarios of island generation are included in the final model, but to simplify the number of scenarios and avoid additional complicating factors in the results, only one scenario of mainland generation is included based on an average of the FES scenarios (National Grid, 2023) (Section 6.3).

As discussed in Section 2.5, the UK has had relative success in net zero policies targeting large scale renewable generation. Aside from issues with rising development costs holding back recent projects, the mechanism has been largely successful, with 30 GW of capacity awarded a contract over the five auction rounds since 2015. Although the majority by capacity has been offshore wind, recent rounds have also awarded contracts to specific categories such as remote island wind and tidal stream (Low Carbon Contracts Company, 2023), indicating the recognised importance of generation diversity. At the distribution-scale though, the FiT has gradually reduced in scope and payments and was closed to new applicants in 2019, reducing the incentives to households which could install small renewables (Castaneda *et al.*, 2020). Other schemes offer support for low-income households, but as mentioned, their implementation has reduced in the last ten years (CCC, 2023). Although the forthcoming future homes standard promises 75% reduction in greenhouse gas emissions, given the slated technology neutrality, it seems unlikely that requirements for specific generation will feature (Kleiner, 2023). It is not clear if the only currently planned policy promoting small-renewables (a VAT rate of 0%) (DESNZ, 2023i) will significantly impact distributed generation.

Due to the limited capacity of the islands' grid to accommodate additional renewable generation, larger generation (defined as >50 MW) (DESNZ, 2023d) would be connected from the point of generation to the mainland (transmission) interconnection rather than local (distribution) networks. Whilst the interconnection would be connected to the distribution network, inter-island distribution network capacity constraints might restrict the transfer of electricity to remoter parts of the islands. If local distribution capacities are limited, increased large-scale generation might not benefit local energy networks and energy-users. The supply scenarios of have been set up to compare the implications with respect to wider energy demand and network infrastructure decisions in the Net Zero model. Thus, the main goal of these supply scenarios is to better understand whether the higher costs of smaller, distributed capacity can be offset by reduced infrastructure and stress on the network at periods of high demand. It could alternatively be more efficient to upgrade the grid to handle higher demand, which will be compared in Section 7.

Distribution and transmission generation, based on two separate datasets, is assigned based on different criteria and depending on its capacity. For large, MW-scale generation, this is using REPD, which tracks the development status of renewable generation from the planning application stages through to operation (BEIS, 2022d).

To consider scenarios at the different ends of potential large-scale generation capacities, the status of projects in the database was used as a filter (Table 6-3). Projects with the status given in the table were included for either scenario.

Table 6-3: REPD development status used to filter between the Independence and BAU/Export scenarios.

Scenario	Independence	BAU/Export
REPD development status	"Operational" "Under construction" "Planning permission granted"	As for Distributed plus: "Planning application submitted" "Revised" "Appeal granted"

Smaller (<50 MW) and distributed domestic generation has been included from several databases. Megawatt-scale generation was also included from the REPD (BEIS, 2022d). FiT (kW) scale generation has been considered using the EPC database (Scottish Government, 2021b), which details where properties are suitable for domestic wind and solar PV generation.

In the model, the location of this new large and small generation is assigned differently. As discussed, large generation on the islands with planned interconnections (Orkney, Shetland and Na h-Eileanan Siar) would be connected to the node where the mainland interconnection reaches (indicated in red in Figure 3-6), not the node it is physically located in. The electricity generated will still be usable for local energy systems, but only within the constraints of local distribution networks (which in many cases are already at capacity, without increased demand). Smaller generation is assumed to connect to the local networks directly, meaning that it is effectively assigned to its geographic node in the PLEXOS model.

Non-renewable capacity on the islands has not been modelled. As per National Grid, SSEN publish a FES report (SSEN, 2023a). 131 MW of island fossil fuel capacity is currently used purely as backup if mainland interconnections fail. FES projections anticipate that through to 2050, this capacity is to be replaced by equivalent biomass capacity to be used as backup. This would be included irrespective of the supply or demand scenarios and would be identical for all scenarios. If maintained by the DNO, it would uniformly increase costs and there would be no difference between scenarios. Therefore, this it has not been included in the model.

To achieve the stated generation capacities in all scenarios, separate categories for unique generation types should be continued, supporting the development of new technologies and maximising whole-system benefits (Matthew and Spataru, 2021) rather than just a "race to the bottom" for electricity prices. This large generation may not necessarily benefit communities affected by them though. Ensuring that large-scale generation (and transmission) projects are developed in not only consultation with local communities affected by them, but that the benefits are fairly allocated would help to maximise development.

For the Independence scenario, with a greater focus on distributed generation, there would be additional requirements. Including generation in the Future Homes Standard (Section 4.6.2) could provide resilience to local networks and better involve households in the benefits of net zero. Energy communities (European Commission, 2023a) are a policy which can support knowledge sharing and best-practice for local deployment of renewables (but also potentially demand-side measures). Barriers from local network capacity would also need to be addressed, which could be through smarter, digitalised solutions and changes to planning regulations. Lastly, research has shown that the benefits of distributed generation tend to go to those more able to afford the up-front costs (Stewart, 2021). Targeted support would be needed to ensure the greatest roll-out and distribution of benefits.

6.4.2 Network scenarios

An essential difference between the main scenarios (Section 3.5) is how the islands energy systems can accommodate additional renewable energy capacity to meet local demand and export energy to the mainland. In three of these (Export, Independence, and Middle Way), this is through electrolysis, flexibility, and efficiency. Additional expenditure in these areas is intended to be offset by reducing or eliminating network upgrade costs. Therefore the modelled networks are the same for these scenarios as the current network (described in Section 6.1.3). This includes existing infrastructure but also the three planned cables from the mainland to Shetland (600 MW), Orkney (300 MW), the Western Isles (600 MW). For the BAU scenario however, it has been assumed that further generation would be developed (without local electrolysis), which would require upgrades to distribution and transmission infrastructure. Interconnections with the mainland would crucially not address grid constraint issues within the islands. Wind farms >50 MW were assumed to connect directly to the transmission network at these mainland interconnections (Section 3.4.5), but this means that any smaller generation on the islands will still contribute to inter-island constraints.

The extent of these upgrades was calculated using initial runs of the model (see Section 3) with planned infrastructure, but increased island demand and renewable generation. This resulted in significant curtailment of local generation as existing networks (already at capacity) were unable to export additional energy produced locally. For each node and associated interconnections (which per Section 3.4.5 were chosen as grid constraints), the increase in capacity of the interconnection was calculated as the average curtailment with existing grid capacity for that node during the summer peak generation scenario. The resulting network capacity allows local generation to export more electricity but does not eliminate curtailment as this would result in over-sized and underutilised capacity. Completely eliminating curtailment is unlikely to be desirable or economical in a net zero energy system, but reducing the island generation curtailment currently of up to 50% (Orkney Renewable Energy Forum, 2014) would surely be beneficial.

Interconnections have been the main limiting factor in the last 20 years of renewable development on the islands. They will therefore have a high marginal value, as they affect the overall capacities of other technologies (mainly generation but also electrolysis). The total proposed capacity of onshore wind for the islands in the REPD (2.4 GW- see Section 6.4.2) is not far off the technical potential of an earlier resource assessment for the islands of 2.8 GW (Baringa, 2013). The suitable land available for generation therefore imposes a hard limit, which is not far off the modelled capacity. Additionally, considering the islands only as the model does (e.g. a single node for the mainland) would support greater interconnection capacity, as the electricity generated could be immediately exported to the mainland node with greater demand. In reality though, electricity exported from the islands is still dependent on congestion on the network in Scotland and Northern England (implications of this for results are discussed in Section 7.5.3). The imbalance of renewable generation (currently mainly onshore wind, but increasingly offshore wind) in Scotland that exceeds local demand (mirroring the situation in the islands) makes the North-South transmission network a crucial congestion point (National Grid, 2023). Building additional islands interconnections would be of little use if the mainland network infrastructure could not cope with transmitting electricity to demand further south. Therefore, the required network upgrades on the mainland to facilitate island capacity will likely be taken up by the huge increase in generation capacity on the mainland before additional island expansion would be considered.

The majority of the interconnections modelled are already under construction (or have become operational since the start of this project, such as the Shetland interconnection) (SSEN Transmission, 2024a). This would therefore not require any further policy support for the Export, Independence, or Middle Way scenarios. For the BAU scenario, with upgraded network capacity, it would only require a continuation of the current approach to building out more renewables, namely constructing greater network capacity.

6.4.3 Electrolysis and BESS scenarios

Electrolysis and BESS capacity for the islands are considered together due to being based on the same constraint - available land area for development. The other modelled aspect of flexibility, DSR, is discussed in the demand chapter - Section 4.7.5 Land area was used as an upper limit on the potential for distributed BESS or hydrogen for each node, so capacity would not be assigned to areas without the land required, which might for example be flagged for nature conservation purposes. Some nodes did not have any available land area for development, so would not be modelled as having distributed capacity. A lower limit for each node was applied of 500 kW for electrolysis and 500 kWh for storage.

Land classification shapefiles were used for all local authorities via their LDPs (Shetland Islands Council, 2014; Orkney Islands Council, 2017b; Argyll and Bute Council, 2019; Highland Council, 2020; North Ayrshire Council, 2020; Comhairle Nan Eileanan Siar, 2021). These categorise areas of land, including suitability for industrial or commercial development. This data was processed in Python and QGIS to split the LDP areas into areas which might be suitable for BESS or hydrogen production. This was used as an upper limit per node to ensure that development was in line with local land availability. To narrow down areas after keeping only the categories in Table 6-4, three constraints were added to the LDP shapefile data (see labelling of Figure 6-11). The resultant constrained land areas were then assigned to the island nodes (Section 3.4.5) to give the total potential land area for each which could be used for BESS or hydrogen production capacity.

(i) *LDP categories:* only LDP areas labelled as related to business, industry, infrastructure, potential development areas, economic, or mix use were included.

(ii) *Existing grid infrastructure:* only areas less than 250m from an existing substation on the distribution network (SSEN, 2019) were included.

(iii) *Distance from existing buildings:* only areas more than 100m from existing building polygons (Geomni, 2020) were included.

Table 6-4: Categories of LDP land use considered suitable for development.

Business and Industry	Infrastructure	Proposals
Established Business and Industry Area	Potential Development Area	Mixed use proposals
Economic	Consultation infrastructure	Infrastructure

Implementing distributed electrolysis and flexibility would require a change or expansion in policy approach. Currently, policy is geared towards large-scale development, which sensible will have the biggest effect in terms of reducing technology costs and developing the nascent market. This could however miss out on the benefits that smaller-scale deployment could have. If hydrogen transport costs exceed reductions through economies of scale, localised hydrogen could improve local energy systems resilience. This would require targeted financial support to compensate electrolysers for wider energy system benefits, such as alleviating network stress or minimising curtailment payments. The second strand of the Net Zero Hydrogen Fund provides CAPEX funding for electrolysis (Innovation Funding Service, 2023), which should encourage investment. This should be continued and could be set up as regular auction rounds for consistency, perhaps with sub-categories for smaller projects which can demonstrate local benefits such as reducing curtailment. For remote communities, funding to support demand and supply simultaneously could help to develop local hydrogen economies. Existing competitions cover industrial demand (Industrial Energy Transformation Fund) or supply of hydrogen (Net Zero Hydrogen Fund) separately and exclude funding used for the other. Given the synergies through co-locating supply and demand, combining or expanding the scope of the funds could help support more optimal and local projects.

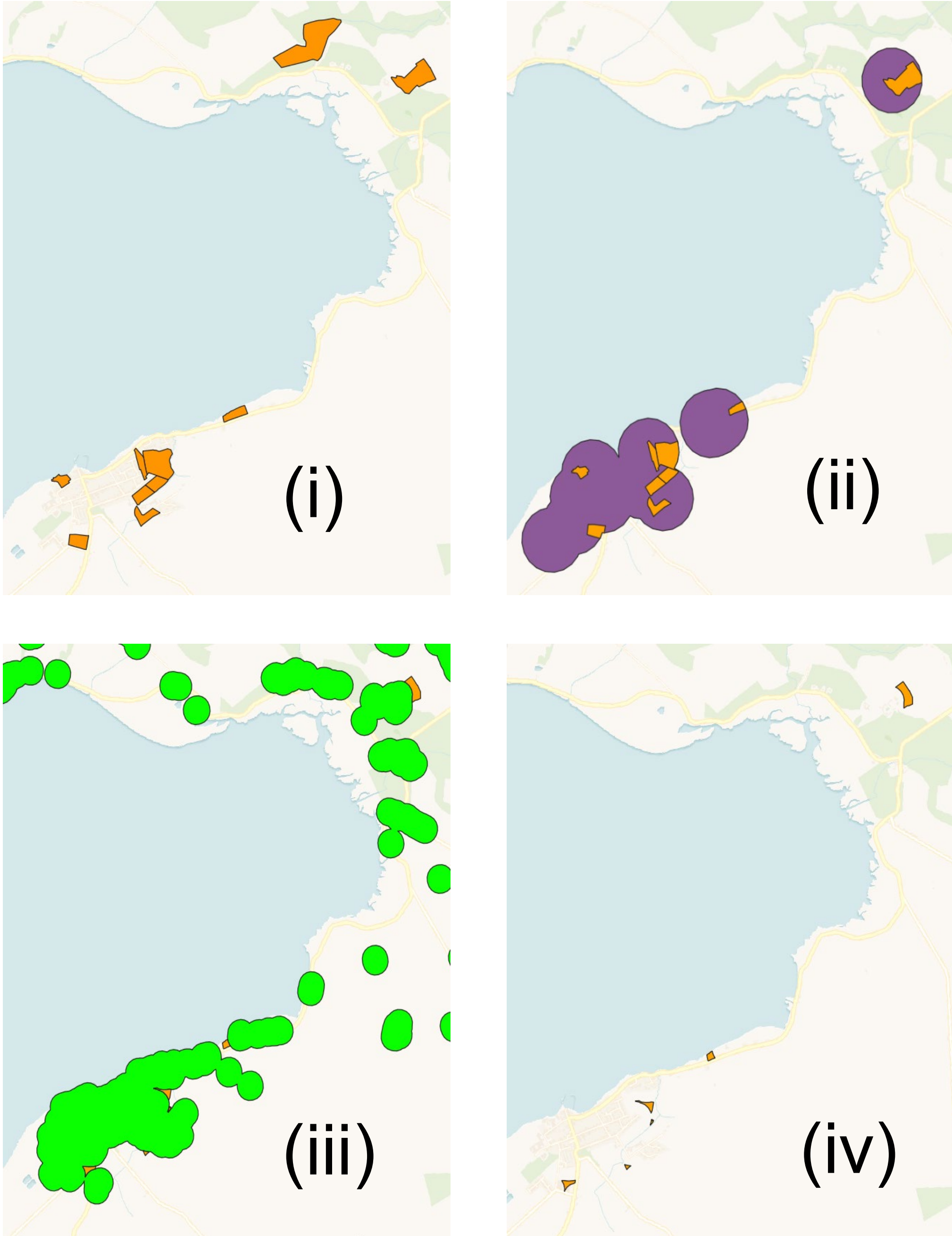

Figure 6-11: Illustration of the constraints applied to calculate the land available for BESS and hydrogen expansion on the islands, where in each step the viable area is shown in orange.
(i) The initial LDP areas labelled for industrial development;
(ii) Areas within 250m of an existing substation on the distribution network (purple);
(iii) Areas more than 100m away from an existing building (green);
(iv) The final constrained LDP areas.

This was used as an upper nodal limit on electrolysis and BESS capacity - other constraints were applied separately. For BESS, the proportion of capacity to peak demand from the FES was used - equivalent to a total of 42 MW for the peak demand of 106 MW in the Low demand scenario. For electrolysis, capacity was assigned according to the following logic:

(i) *BAU:* no local electrolyser capacity - excess renewable energy is exported as electricity.

(ii) *Independence:* based on local hydrogen demand and a capacity factor of 60% (National Grid, 2023), electrolysis capacity was calculated such that local demand could be met by local production.

(iii) *Export:* in addition to local demand, the average local curtailment in the summer peak generation scenario (with electrolysis) was calculated using initial runs of the model. For each node, whichever was greater between this curtailment and the local hydrogen demand was used.

(iv) *Middle Way:* the average of the Independence and Export scenarios.

6.5 Capacities of supply scenarios for the Net Zero model

This section describes the applied results of the logic from the previous section, presenting the modelled capacity for each aspect of the Net Zero model. The logic of the scenarios is described in Table 6-5.

Table 6-5: Reiteration of the scenarios defined in Table 3-3.

	Definition	*Scenarios*	*Description*
Supply	Planned and potential renewable generation capacity on the islands.	BAU, Export	Reliance on energy imported from the mainland, e.g. offshore wind, nuclear, CCUS. Greater stress on transmission and distribution infrastructure.
		Independence	Greater investment in local, small-scale solar PV and onshore wind. More complex balancing of system but less stress on transmission.
Electrolysis	Local electrolyser capacity on the islands; hydrogen used locally or exported.	Independence	Electrolysis capacity for each node is dictated by local demand, assuming a capacity factor of 60%. This is also constrained by the available Local development plan (LDP) area.
		Export	Where average local curtailment of renewable generation due to grid constraints is greater than the electrolysis capacity from demand, this has been used to dictate capacity.
		BAU	There is no islands electrolysis capacity - hydrogen-based fuels are imported fuels.
Flexibility	Nodal capacity for BESS and DSR on the islands.	Independence	Nodal BESS is assumed at the proportion of demand to BESS from FES, subject to LDP constraints. DSR is assumed at a 50% uptake rate for certain categories of demand. This will help to balance local networks and deal with grid constraints.
		BAU, Export	No distributed flexibility is considered for the islands. Meeting demand will be entirely dependent on the capacity of local networks to transmit electricity at the required time.
Networks	Transmission network upgrades between nodes.	BAU	Electricity networks are upgraded by the minimum required to displace the average curtailment of initial model runs. This does not eliminate curtailment but will reduce it.
		Export, Independence	Existing infrastructure is used as an input to the model with no alteration. In cases with increased demand, there could be unserved energy.

6.5.1 Megawatt-scale renewables for the islands

From the criteria used to filter the REPD, the total capacity by scenario is given in Table 6-5 and the spatial distribution in Figure 6-12. Between the High and Low scenarios, the generation capacity connected to local networks is largely the same, highlighting the potential effects of greater transmission scale generation on local networks. This is modelled as being connected to the point on the islands which returns to the mainland (shown in red in Figure 6-12). While the generation capacity of all scenarios greatly exceeds peak demand (about 200 MW in the High demand scenario; Section 4.7.3), periods of low generation could be insufficient for local demand. Additionally, transmission connected infrastructure will not improve energy access for the island areas connected by grid constraints.

Table 6-6: Total modelled island MW-scale renewable capacity by scenario.

	Scenario	BAU/Export	Middle	Independence
Transmission (>50 MW)	*Onshore wind*	2,000	1,552	1,103
	Tidal current	304	204	104
Distributed (<50 MW)	*Onshore wind*	152	137	122
	Tidal current	4	4	4
	Total	2,460	1,897	1,333

Figure 6-12: Total generation capacity for the BAU/Export (top) and Independence (bottom) scenario for Shetland and Orkney (left); Na h-Eileanan Siar and Highlands (centre); Argyll and Bute and North Ayrshire (right). Codes refer to each node of the final model (Section 3.4.5), with tranmission networked nodes shown in red.

6.5.2 Kilowatt-scale renewables for the islands

Between the BAU/Export and Independence scenarios, the extremes of potential capacity for wind and solar PV have been included. However, analysis of the EPC recommended improvements data used reveals an oversight in the SAP used to calculate EPC ratings. It appears that generation is over-recommended as an improvement to EPC ratings, as it is unrelated to local weather conditions. Comparing the recommended installation of wind and solar PV in the EPC database with statistics for actual installed generation from FiT statistics (BEIS, 2020d) demonstrates this discrepancy (Table 6-6).

Table 6-7: Difference between the EPC recommended (Scottish Government, 2021b) *and installed FiT* (BEIS, 2020d) *capacities for wind and solar PV (MW).*

	Local authority	Orkney	Shetland	Na h-Eileanan Siar
Wind	*EPC*	17.2	20.1	25.2
	FiT	18.7	6.8	9.7
	Difference from FiT	-8%	+195%	+160%
Solar PV	*EPC*	16.5	18.3	22.3
	FiT	1.4	0.2	1.2
	Difference from FiT	+1079%	+9050%	1758%

For wind on Orkney, the installed (FiT) capacity exceeds the recommended capacity from the EPC database, which indicates that perhaps favourable local planning laws facilitated higher uptake. High wind capacity factors (Orkney Renewable Energy Forum, 2014) also allow greater generation (and so return on investment) for households relative to SAP predictions. Similar levels of urbanisation across the islands are not likely to limit deployment in Shetland or Na h-Eileanan Siar compared with Orkney, so it seems the EPC capacities could be treated as an upper limit, which has been fulfilled in Orkney but not elsewhere.

For solar PV though, the difference between the installed (FiT) and recommended (EPC) capacities is enormous - up to 9050% for Shetland. The SAP used to perform EPC assessments, recommends wind or solar PV based on average UK weather conditions (BRE, 2014), not local ones. For the islands, with exceptional local wind resources but lower solar irradiances at the northern extremities of the UK, the potential for wind is underestimated, while the potential for solar PV is highly overestimated.

To address this discrepancy in the EPC dataset, the existing FiT capacity was used to scale for more representative wind and solar PV capacities (Table 6-7). Although the capacity appears significant relative to local demand (with peak winter demand of about 120 MW currently) (SSEN, 2021), the modelled wind capacity for Orkney (17.2 MW) is actually lower than the current installed FiT capacity (19.0 MW) (Table 6-6).

This capacity has been applied according to the households detailed in the demand model (Section 4.1), then grouped into the nodal areas (Section 3.4.5) and combined with large-scale, distribution connected capacity to use as an input to PLEXOS.

Table 6-8: Modelled distribution network connected scale renewable capacity (MW).

Scenario	BAU/Export	Middle	Independence
Wind	39.2	66.6	93.0
Solar PV	4.0	10.0	16.0

6.5.3 Scenarios of network capacity

For all except the BAU scenario, interconnection capacity has been modelled based on network shapefiles (Section 6.1.3) and the nodal structure for the final model (Section 3.4.5) to highlight constraints in the network. Planned expansion of interconnections for the three main island groups (Orkney, Shetland, and the Western Isles) has been included for all scenarios. For the BAU scenario, additional capacity to reduce curtailment has been added based on the method described in Section 6.4.2. Upgraded capacity is shown in red for Figure 6-13.

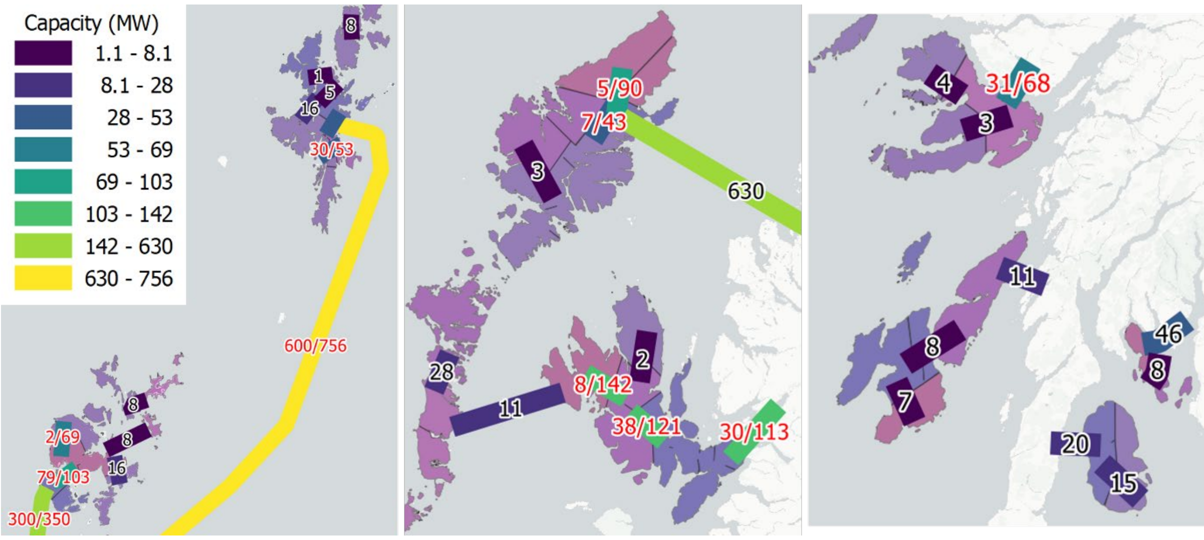

Figure 6-13: Modelled interconnections for all scenarios - where capacity has been upgraded, the label is shown in red, with the greater of the two values being the BAU scenario capacity. All others are the same between scenarios.

This has resulted in the summary changes in Table 6-8: although the three main planned upgrades are more significant, the BAU scenario requires more widespread upgrading in twelve nodes. How this compares with other distributed technologies and at what cost, will be analysed in the Net Zero results (Chapter 7).

Table 6-9: Modelled interconnection upgrades.

Aspect	*Value*	*Units*	*Scenario*
Existing capacity (SSEN, 2019)	978.7	MW	
Planned capacity	**2178.7**	**MW**	**Export, Independence, and Middle Way**
Number of connections upgraded	12	-	
Existing capacity to be upgraded	1304.4	MW	
Capacity upgraded by	633.6	MW	
Percent upgraded by	49%		
New total capacity	**2812.3**	**MW**	**BAU**

6.5.4 Scenarios of electrolysis and BESS capacities

The total capacity for island electrolysis and BESS are given in Figure 6-14, noting that the BAU electrolysis, BAU BESS, and Export BESS capacity is zero. Assuming an energy density of 55 kW/m^2 (as for lithium-ion) (BEIS, 2018b) would result in 0.13% of the constrained LDP land area being used. The proportion of local land area available varies significantly between local authority areas though, with some having an excess and others being constrained by available space. Some nodes had no available land area for development and so no potential for BESS or electrolysis.

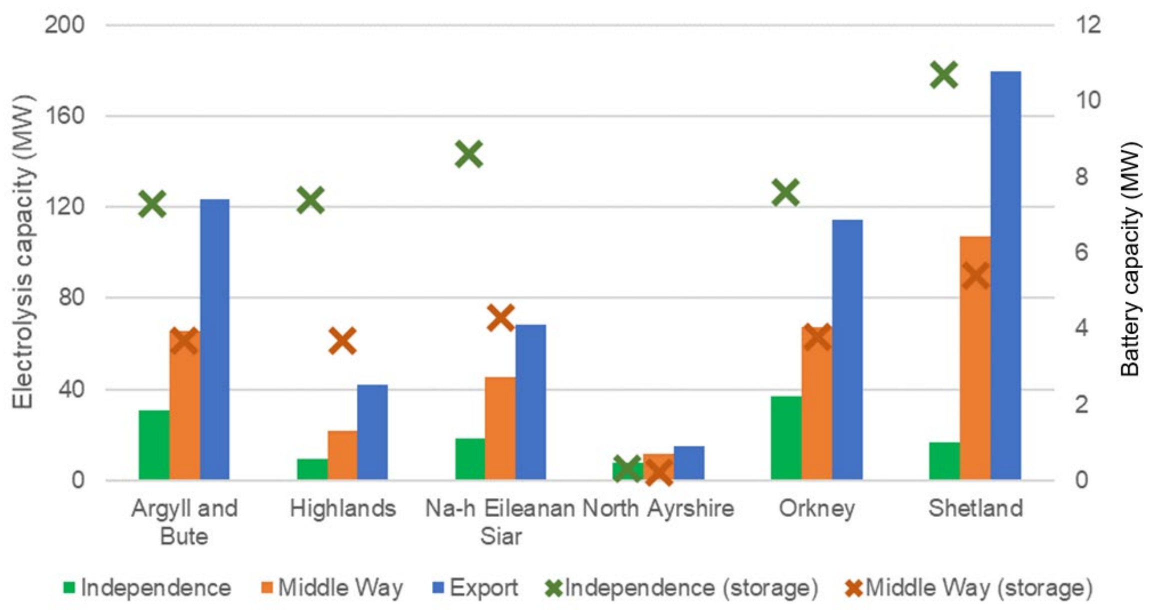

Figure 6-14: Electrolysis and battery capacity per local authority and scenario – BAU does not have capacity for BESS or electrolysis.

6.6 Discussion of supply, networks, and flexibility modelling

The supply models presented in this chapter have been developed for two purposes: to validate the electricity model (Section 6.2) and to be integrated with the Net Zero model (Chapter 7).

The validation of the model demonstrates the supply model captures key behaviours needed to represent mainland generation for the final Net Zero model focusing on the islands. In terms of the merit order of dispatch, total annual generation matches the actual to within ±13%. This could be improved with further work, perhaps through better capture of long-term contracts for certain types of generation. Average monthly electricity prices demonstrate how the seasonality of demand causes changes in prices due to moving up or down the merit order but clearly lacks representation of the irregular spikes in electricity prices. As gas was price-setting 98% of the time in 2021(Maximov *et al.*, 2023), it seems highly likely this discrepancy is due to the assumed day-ahead gas prices, which greatly simplifies the gas market.

Projecting forward to 2045 though, greatly increased renewable capacity should mean that gas (or any other thermal generation) spends much less time setting the electricity price, which might minimise the effect of gas prices. In terms of the merit order of the mainland generation (including electrolysis which is assumed to only operate with excess renewable energy), future changes in fuel prices could affect the predicted price of electricity, but the lack of “fuel-on-fuel” competition in the UK makes the merit order less likely to change (Maximov *et al.*, 2023).

Wind generation timings are captured by the Renewables Ninja based wind capacity factor model. However, the model tends to over-predict peak generation, even after application of a correction factor. It is unclear how this could be improved, but it could be related to the approximated power curves, grouping of generation by node, or underlying wind data from the ERA5 dataset that the API is based on. This could be interrogated with further work but would require more generation data for specific wind turbines to compare with the modelled output. Additionally, overprediction of peak generation only affects the results of one of the two extreme weather scenarios (discussed in Section 7.5.4). In the summer (high wind, low demand) scenario, generation could be exaggerated, but the winter (low wind, high demand) has been selected due to minimum wind production, which would make estimation of peak generation inconsequential. The recorded data has a better match looking at the correlation factor between nodes, with the over-correlation at closer distances expected due to the nodal grouping. Further modelling would likely improve results, but in the context of the final Net Zero model, the essential behaviour required to represent renewable generation is adequate.

The additional value of island and other generation types have been recognised by the Government via separate CfD categories for “remote island wind” and “tidal stream”. Despite the well-publicised failure of the 2023 CfD round to attract any bids for offshore wind, it was a success for tidal stream, with twice as many projects as the previous round for a 17% lower price (Low Carbon Contracts Company, 2023). Having a separate category for island wind recognises that island projects can face different challenges to mainland equivalents, which should help to encourage development. This may not however mitigate other development risks. The 443 MW Viking wind farm on Shetland (planned for completion in 2024) has been the main condition for 600 MW interconnection going ahead. The planning application was beset by six years of legal challenges, with the ultimate developer only deciding to go ahead in 2020 (Viking Energy, 2023). Although Orkney particularly has a more favourable disposition to renewable energy development (with the highest FiT capacity in the UK), Shetland and Na h-Eileanan Siar are less so, with large developments appearing to run into longer delays. The distinction between large, hundreds-of-megawatt projects should be made though, as larger projects with greater footprints and impact could attract greater opposition. Additionally, despite the separate CfD categories, its not clear if they will be enough to allay Ofgem’s fears of underutilised interconnections that has continued to delay projects on the islands. More detail on the specific factors that could limit further development of generation (or potential BESS and electrolysis for that matter) is not clear from this research and would require further investigation. The supply capacity scenarios have been set up to consider how differing levels of infrastructure requirements could be traded off with other investments in the energy system, and are discussed in the whole model context in Section 8.2.

The ultimate purpose of this chapter is to integrate with the islands’ Net Zero model, representation of the mainland need not capture the exact generation behaviour. To simplify, the only aspect of behaviour needed is to capture island interconnection electricity flows and electricity price. As only wind and tidal stream are modelled on the islands, the direction of interconnection flows will depend mainly on whether generation exceeds demand in each modelled node. If local generation is greater than mainland demand in both locations, it will be curtailed; if island generation is in excess, electricity can be exported; vice versa and the islands will import. The main thing the mainland model needs to do is represent when there is an excess of generation and whether electricity would be imported or exported. Through the daily variability in prices, timing of wind generation, and geographic correlation of generation, the validation model captures this behaviour. Other factors could however affect this balance for the mainland. Only one scenario of mainland generation capacity is considered for simplicity, which is heavily dependent on wind. It is not clear from the FES how feasible the total increase in wind capacity of seven times (National Grid, 2023) is in terms of physical space or infrastructure capacity. If the Government's commitment to CCUS and/or nuclear is successful, perhaps net zero would be even more reliant on these technologies. This would alter the marginal cost curve and so what balance of generation is suitable for the islands, would need to be considered in analysis of the Net Zero model results (Section 7.5.4).

In terms of supply-side technology capacities by scenario, relevant constraints have been applied to ensure the technical feasibility of capacity for each node. Only generation either operational, under construction, or with planning permission approved is included. This does not cover the "chicken and egg" dilemma that developers, the DNO, and Ofgem have been stuck in for the last two decades with respect to minimum generation required for new interconnections. This assumes that developers would be willing to invest in developing new projects, even if grid connection was not guaranteed without a wider threshold capacity being met. In reality, the process has involved more than a decade of to-and-fro with regulators. Implications of this in terms of the trade-off between larger and smaller generation capacity, as set up in the two scenarios, is discussed in Section 8.2.

For electrolysis and BESS, three constraints were applied: only using land area available for industrial development, land less than 250m from an existing substation, and land more than 100m from any existing building. UK Government guidance on buffer zones for energy projects, used by local councils to develop their own plans, recommends flexibility rather than setting a specific minimum distance, therefore these constraints are likely excessive (Department for Levelling Up Housing and Communities, 2023). Despite this, the total available land area used for storage and electrolysis proportional to that assumed for the whole UK in the FES (National Grid, 2023) would be only 0.13% of the total. Basing the capacity on the LDP available land area means nodes without space for development will not be over-developed. However, these constraints only cover technical and not economic feasibility. Whether or not they are economically feasible would depend more on the market appetite for investment, policy support, local government acceptability of development, and other factors are be discussed in Chapter 8.

7 What could net zero look like for the islands?

Through a combination of the modelling methodologies described, the final Net Zero model has been set-up to improve understanding of how the islands could eliminate greenhouse gas emissions. Scenarios of technology and weather are considered in order to understand to trade-off between different energy system technologies, scales, and structuring. The structure, optimisation process, and scenarios for the model are described in Chapter 3. The three sub-models' methodologies of Demand (Chapter 4), Biogas (Chapter 5), and Supply (Chapter 6) have been discussed, along with initial results and scenarios for the Net Zero model. The Net Zero model is set up in detail for the Scottish islands in 2045, with some simplification for the mainland (Figure 7-1). The representation of electricity dispatch, the Electricity Market object in PLEXOS, is similar to the validation model (Section 6.2), albeit with a different nodal structure due to focusing on the islands and computational time constraints. The Net Zero model expands upon the Electricity Market only model, to also include balancing of supply and demand for hydrogen, biogas, and heat. Electricity and Gas (hydrogen and biogas) Markets are interlinked through hydrogen production ("power2x" objects in PLEXOS); heat, biogas, and hydrogen are interlinked through boilers used to meet heating demand.

Inputs to the Net Zero model from outputs of the other models (Demand, Biogas, and Supply) have eight configurations of the four scenarios and two extreme weather periods (summer - high wind, low demand; and winter - low wind, high demand). This represents the extremities of demand and supply under weather conditions most stressful to the stability of a UK-wide renewable energy-dependent energy system. These configurations of the model are facilitated through using the PLEXOS API in Python (Energy Exemplar, 2023b), allowing for data outputs from the other models to be added to PLEXOS more easily than the manual process used in the validation model (Section 6), as well as automating the execution of models.

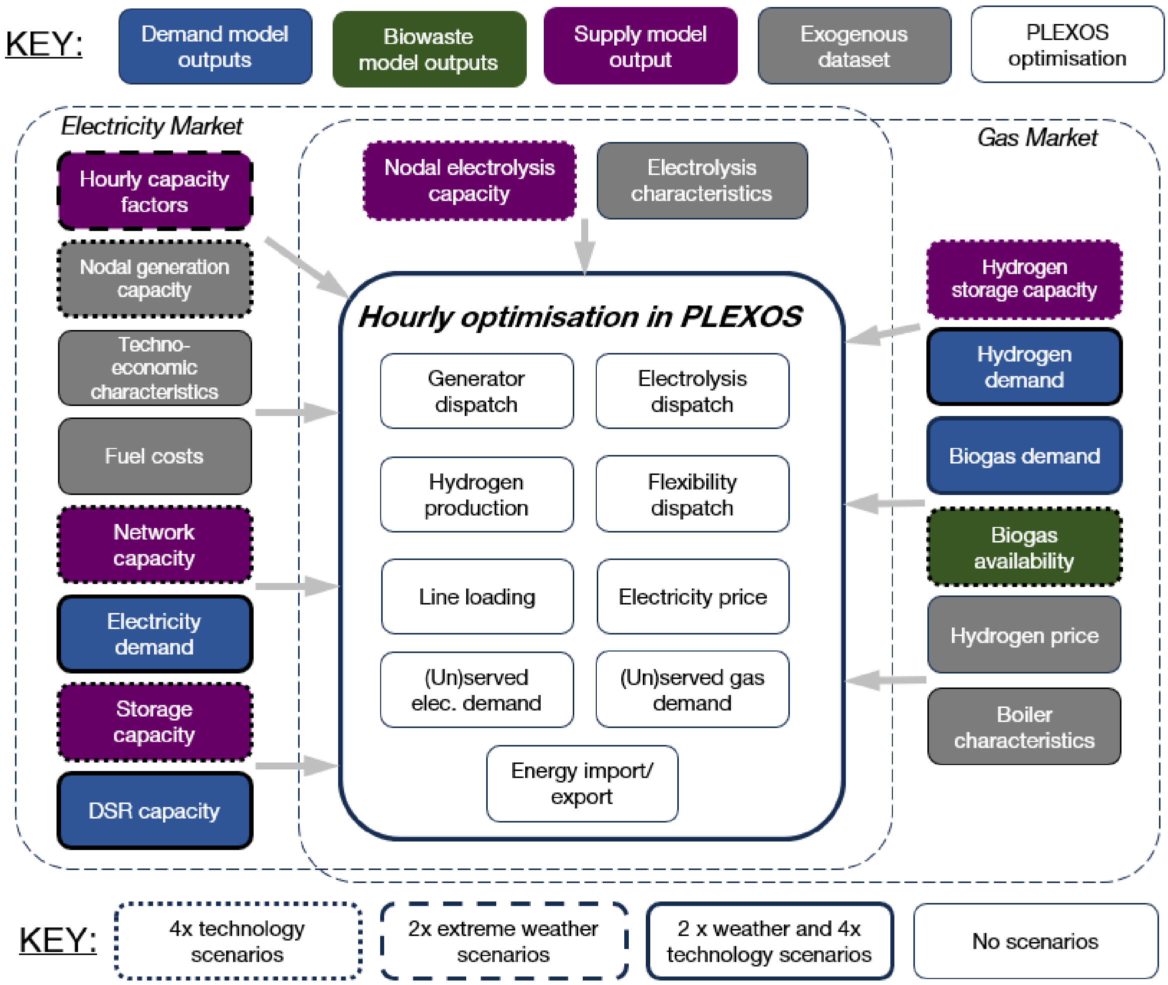

Figure 7-1: As shown in Chapter 3, the structure of the Net Zero model in PLEXOS, Inputs from other models are colour coded and scenarios are indicated by the outline of the box. Electricity and Gas Markets here refer to the model structure in PLEXOS, with the two being connected through electrolysis. Only the hourly dispatch of energy is optimised in PLEXOS- all data categories outside the centre bubble are set up according to the deterministic scenarios outlined in Section 3.4 and described in Section 4, 5, and 6.

The four main scenarios have been set up to compare different configurations of technology deployment. To summarise the key results of these scenarios:

BAU: upgraded network capacity, island generation, and lack of electrolyser efficiency losses allows for the greatest energy exports, but also the highest absolute and relative curtailment. Due to a lack of efficiency investment, it has the second highest network stress and higher winter (low generation) electricity imports – but not in the summer when generation is highest. The overall cost is dominated by network upgrade and hydrogen import/storage costs, which as well as being the largest categories are also very uncertain.

Export: island electrolysis allows for greater utilisation of local generation, reducing curtailment without network upgrades. Although total energy exports from the islands are not the highest, the export value is dependent on the assumed price of hydrogen. Network stress is the highest, highlighting that although electrolysis could utilise curtailed electricity, it could increase the complexity of network balancing. The costs of storing hydrogen, for local demand or export are high, raising further questions about the suitability of hydrogen as a commodity for remote communities.

Independence: the combination of efficiency, flexibility, and distributed generation allows for the highest proportion of energy to exported and lowest curtailment. Minimal network stress indicates that the conservatively modelled generation capacity could be increased. Local electrolysis could technically meet local demand to minimise uncertain hydrogen import and storage costs, which contributes to the scenario having the smallest uncertainty in overall cost. This again raises questions though about the economic feasibility of small-scale electrolysis and hydrogen demand. Even with costs scaled to match the balance of generation and demand measures on the mainland, this scenario has the lowest CAPEX and OPEX.

Middle Way: as a midpoint of the other scenarios, results highlight that incremental changes in model inputs would result in similar outcomes, e.g. that the correlation between inputs and outputs is likely linear. Electrolysis capacity sized between matching local demand and minimising curtailment could be feasible but again depends on assumptions which will be discussed.

7.1 Monthly balances of electricity, hydrogen, and heat energy

With the addition of hydrogen, biogas and heat demand in the Net Zero model, the first step to examine is the overall energy balances (Figure 7-2). For electricity and hydrogen in all scenarios (excepting BAU, which has no islands electrolysis capacity – Section 6.4.3), the islands are net exporters of energy, but this varies by energy type. The BAU and Export scenario, with identical electricity and hydrogen demand (based on historic efficiency policies – Section 4.6), are differentiated by the electrolysis demand and supply of locally produced hydrogen produced in sufficient quantities to be exported in either summer or winter. The net energy export is lower in the Export scenario due to electrolysis efficiency losses (the BAU scenario has no island electrolysis demand), but the value of this would depend on the price of hydrogen, which is discussed in Section 7.5.1.

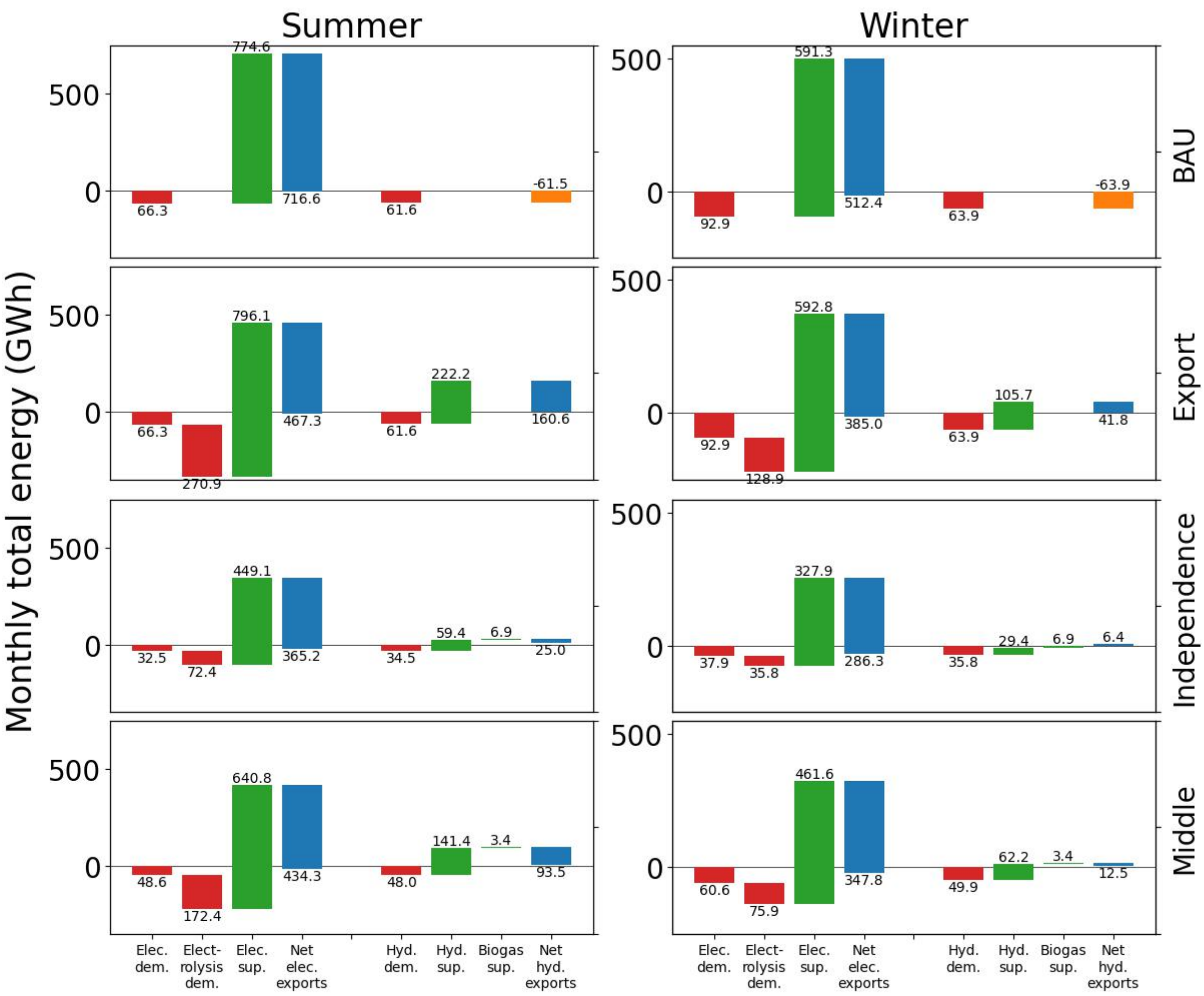

Figure 7-2: Overall energy balances for electricity, hydrogen, and biogas for the four technology and two weather scenarios. Island demand is red, production is green; net exports are positive (blue) and imports are negative (orange).

Essentially, the Independence and Middle Way scenarios have similar overall energy balances, but with a lower capacity relative to the Export scenario in excess hydrogen production. The combination of reduced demand and biogas however allows proportionally greater export of electricity or hydrogen. The potential for biogas varies by scenario- it could displace up to 7% and 20% of hydrogen demand for the Middle Way and Independence scenario respectively. Depending on the configuration of policies though (i.e. the biowaste and demand efficiency scenarios are not co-dependent), it could be as low as 5% of hydrogen demand for the Middle biogas scenario and BAU demand scenario. Reduced reliance on imports will help to improve the energy independence of the islands but needs to be considered against other aspects such as the overall cost (Section 7.4), curtailment (Section 7.2), network loading (Section 7.2.1), hydrogen storage (Section 7.3.1), and flexibility (Section 7.2.2).

7.2 The role of the electricity system in net zero

Electricity is the energy type likely to have the most significant role in the overall energy balance. To summarise, the main aspects varying by scenario are generation (island capacity of 1.4-2.4 GW), demand (76-138 MW average in the winter), curtailed generation, imports, and exports (both to the mainland). This is shown by scenario in Figure 7-3 (noting that the top half of demand in dark orange denotes electrolysis electricity demand - data callouts indicate the proportion of generation for that scenario).

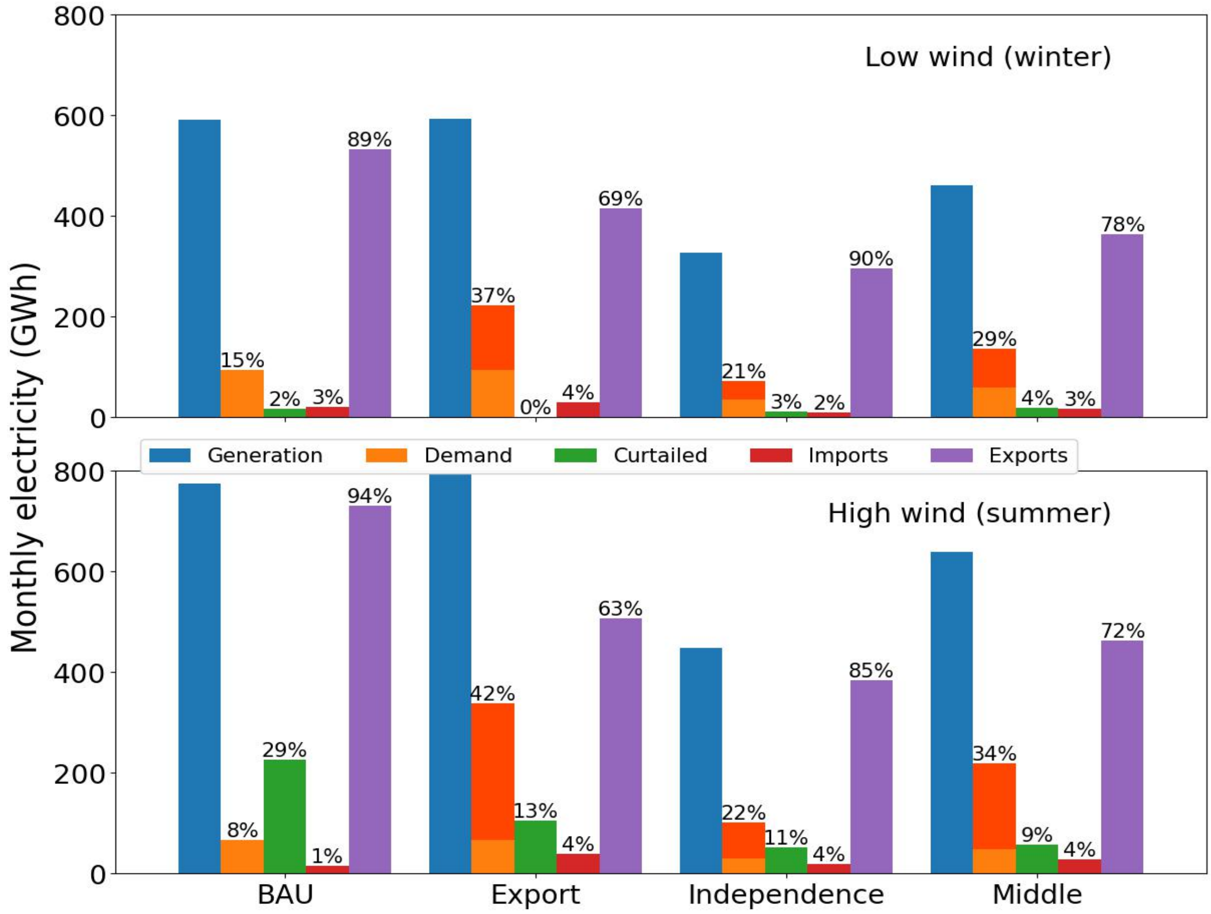

Figure 7-3: Main aspects of electricity generation only for the islands, where the callouts give the proportion of that aspect relative to generation (shown in blue). Demand is split into electricity (light orange - bottom) and electrolysis (dark orange - top).

Common to all scenarios is planned islands renewable capacity (Section 6.5.1) greatly exceeding local demand, facilitating 63-93% electricity exports. Electricity exports of up to 12 times monthly demand in the BAU summer scenario. However, it still does not allow the islands to be completely independent of the mainland. Electricity imports are required totalling 10-18% of demand in the modelled worst-case winter month. Even in the independence scenario, with maximum local flexibility and minimum demand through efficiency measures, electricity imports from the mainland are still needed, particularly in local authority areas with lower generation capacities. Apart from these commonalities, scenarios have different approaches to managing the net zero electricity balances:

BAU: the greater generation capacity (2.4 GW) allows for nearly double the electricity exports of the Independence scenario (1.4 GW), but even with a 29% higher network capacity, absolute and relative curtailment is the highest. The 28% summer curtailment is consistent with reports that certain generators in Orkney are curtailed more than 50% of the time under the ANM system (Urban Foresight, 2015). Although seemingly inefficient, high curtailment might not be a sign of a sub-optimal power system depending on the overall system configuration.

Export: electrolysis capacity sized for exporting hydrogen reduces curtailment in the summer and eliminates it in the winter. In the summer (high wind, low demand), electrolysis demand is 4.0 times greater than the base electricity demand (1.3 times in the modelled worst-case winter month). When local generation is not available, but wind is price-setting on the mainland, the islands' electrolysis also runs, resulting in the highest electricity imports. For the islands with generation in excess of local demand, electrolysis helps maximise the use of the electricity without requiring network upgrades – discussed in Section 7.2.1.

Independence: with the lowest electricity demand; highest flexibility and BESS; and electrolysis sized to meet demand; this scenario has the lowest absolute electricity imports and higher export potential as a proportion. Although hydrogen demand is reduced through efficiency, electrolysis demand is 2.4 times the electricity demand in the summer (high wind, low demand). Even with greater focus on demand-side measures, imports from the mainland are required 2.5% for of the time for regions with higher renewable capacity (but much less than the 30% for BAU and Export scenarios), highlighting the necessity of interconnections, dispatchable generation, and/or longer-term storage.

Middle Way: the last scenario displays similar results to Independence, but with reduced extents of all aspects - higher proportional and absolute demand, imports, and exports. As this scenario was included mainly to consider the balances of costs, it will be discussed in more detail in Section 7.4.

7.2.1 Interconnection loading, flows, and unserved energy

Network upgrades are one of the key trade-offs between scenarios. Existing networks are already constrained with less generation and demand electrification than modelled, so it is critical to understand behaviour under increased load. More island renewables will make the network limiting electricity export to the mainland more likely and demand electrification will increase network stress at periods of peak demand.

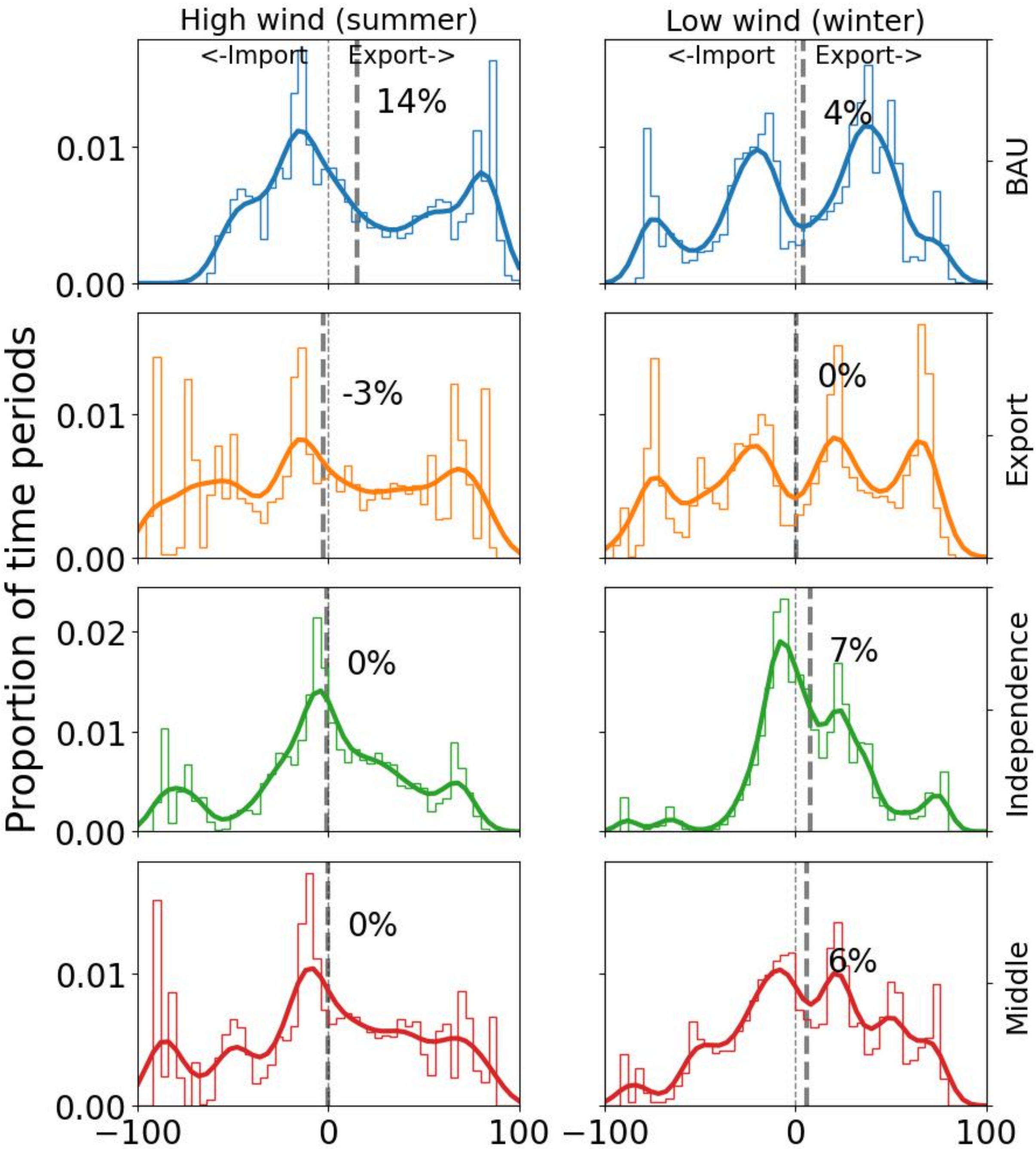

Figure 7-4: Distribution of island area grouped line load, where negative (left) is importing from the mainland and positive (right) is exporting. The average line flow is shown by the dashed line and callout.

This can be analysed as the net flow between nodes grouped for each distinct island zone connected to the mainland (Orkney, Shetland, Lewis & Harris, Arran, Mull, Islay & Jura, Bute, Skye, and Uists – see Figure 3-6) in terms of imports (flow away from the mainland) and exports (towards the mainland) (Figure 7-4). The shape of each density curve (the solid line) reveals the differences in network behaviour between the four scenarios under the same weather conditions. Essentially, density clustered at the far right (exporting) or left (importing) of each graph denotes peak line stress, whereas density in the middle of the graph denotes underutilised interconnections. Greater time spent under peak loading increases dependence on the interconnection to meet the islands electricity demands.

To reiterate, network upgrades are only included for BAU; Export uses electrolysis for excess generation; and Independence combines efficiency, flexibility, and BESS. With the largest generation capacity, BAU has the highest export of electricity (largest clustering on right-hand side) in the high-wind summer weather period - also in the winter scenario, with a peak of export at about 50%-line loading. The Export scenario also has a large peak close to 100% due to it having the same renewable capacity as BAU without an upgraded grid. When electrolysis is at peak capacity, the excess wind can still exceed grid capacity, resulting in the twin peaks on the right-hand side of the orange plot. Electricity exports for the other two scenarios are still sizable with lower renewable generation capacities, but without peaks close to 100% network capacity, indicating that network stress is much lower.

Despite the excess local wind generation in the summer (high wind), all scenarios except BAU have large imports spikes on the left side close to 100% network capacity due to local electrolysis. For the main island groups, the largest generation is connected to the transmission network at the mainland connected nodes (Section 6.4.1). Even if the generation was physically located in another node, connection to the grid would be direct to the mainland interconnection, meaning electricity generated would have to pass through this substation to meet demand in that node (see Section 3.4.5 and Figure 3-6 for the specific nodes). This means that if the large-scale generation is at peak generation, the line flow would be shown as importing as it is dispatched (away from the mainland being importing in Figure 7-4) from the main node towards the outer nodes. This could also be occurring when island generation is lower but there is excess wind from the mainland node which could be imported. Electrolysis puts significant additional stress on the networks which would need to be managed.

In terms of imports, the effect of demand-side aspects (efficiency, distributed generation, BESS, and flexibility) is clear, particularly in the winter scenario. They essentially have the effect of shortening the tail on the left side - lower peak and average demand will reduce electricity imports. This is clear in the left side of the Independence scenario graph clustering towards the centre (0% - e.g. import/export neutral) more than other scenarios. This also allows the more resilient Independence and Middle Way scenarios to have higher average net line capacity exports of 7% and 6% respectively - despite lower generation capacities. With lower local demand, reduced network stress in Figure 7-4 indicates that a higher than modelled renewable capacity could be feasible without further network upgrades. This makes the two demand focused scenarios more resilient to the worst-case winter scenario. Although more generation can improve resilience, at periods of low generation without diversification, demand-side options could be more effective.

The upgraded network of the BAU scenario reduces peak network stress (time spent at >95% of capacity), whereas the Independent and Middle Way scenarios achieve this through demand-side measures. The greater electrolysis capacity in the Export scenario again increases the stress on the network, which would require management, particularly regarding in balancing the network. The converse of the demand-side measures in both the Independence and Middle Way scenarios is that the proportion of underutilised network time (defined as <25% loading) is much higher. Distributed technologies can minimise network loading by allowing localised balancing of supply and demand within each model node. The nodal structure of the model does not however capture the burden of network stress on more localised networks, particularly at peak generation. The potential implications for this shift in infrastructure utilisation are discussed in Section 8.2.

Network upgrades have only been considered for generation (Section 6.4.2). As such, with limited commitment to energy efficiency in the BAU and Export scenarios, there is unserved energy in the model 14-51% of the time in the winter scenario for four nodes. Two of these are located at the outer edge of their islands with very limited network capacity, whilst the other two are both on the island of Islay, which has higher local demand from whisky distilling (Section 5.6). None has any modelled generation capacity. Clearly areas with limited network capacity or greater demand would require network upgrades under the current trajectory of energy efficiency policy described in Section 4.6. The Middle Way scenario, which still does not achieve all stated efficiency targets but has more modest improvements (as well as some BESS and flexibility), has no unserved energy for any of the nodes.

7.2.2 The contribution of local flexibility and BESS

Flexibility is modelled with nodal BESS, DSR, and V2G charging potential for the Independence and Middle Way scenarios - it is not included in BAU or Export. Its contribution can be assessed in several ways.

Looking at the (wholesale) price paid for and the total cost of electricity (Table 7-1). Reducing electricity costs through shifting demand away from peaks (of demand or fossil fuel generation) is the main mechanism currently used to encourage distributed flexibility. In this model though, additional renewable generation in the BAU and Export scenarios outweighs these effects, with the Independence scenario (e.g. lowest overall generation capacity) having the highest average prices. Particularly in the Winter scenario, national electricity prices are dominated by periods of unserved energy on the mainland, which sets the price at £6,000 /MWh. The additional 1 GW of generation in the BAU reduces the number of hours with unserved energy, and this has a significant effect on electricity prices. Excluding periods of unserved energy at this extreme price results in the same order of scenario prices.

Table 7-1: Average (wholesale) prices and total cost of electricity for the islands (excluding electrolysis demand and negative load caused by distributed generation).

	Winter		*Summer*	
	Price (£/MWh)	*Total cost (£M)*	*Price (£/MWh)*	*Total cost (£M)*
BAU	506.9	40.5	64.5	3.7
Export	469.5	37.5	64.5	3.7
Independence	657.8	6.8	66.4	0.9
Middle	506.4	19.2	66.9	2.3

The winter month consists of two weeks with sufficient renewable generation (i.e. wind) to meet demand, followed by two weeks of wind drought and hence unserved energy (see Figure 6-10 for illustration of this shift in wind patterns). In the summer period, there is excess renewable the entire month (i.e. peaking generation is not needed, only curtailment of renewables). In either case, there is no variability in the generation mix at the resolution which the flexibility is available (several hours for DSR or up to a day for BESS). This appears to show that how DSR is assumed to operate currently (avoiding daily peak demand) might be less viable during future periods of high renewable generation. This is not to say that other services not factored into the model would not have value, such as higher resolution balancing or frequency control.

The total cost per scenario is however much lower in the Independence and Middle Way scenarios, due to a combination of efficiency and distributed generation. Monthly demand in the Independence scenario is 40% of the BAU or Export scenarios, but with the distributed generation (assuming there is no payment for excess generation), the total cost of meeting demand is 76% lower for Independence. Distributed generation results in reduced bills for local households and businesses (Section 4.7.4) - to a greater extent than larger-scale generation reducing wholesale prices (Table 7-1).

Flexibility has a clear effect in reducing line stress, particularly for nodes with no modelled generation capacity (Figure 7-5). Excess local renewable generation, rarely less than local demand (Figure 7-2), makes flexibility effects clear. Independence, followed by the Middle Way scenario, are less dependent on imports (the left side of Figure 7-5), with hardly any of the time in the Independence scenario spent at more than 50%-line import capacity. There is also less time at peak line stress importing or exporting (defined as >75% and shown as red hatching). Periods of exporting energy here, despite the nodes having no generation, is likely due to energy passing through from the outer nodes towards the mainland. Flexibility, combined with lower demand, can clearly reduce the import dependency of isolated communities, reduce network stress, and increase regional energy export potential.

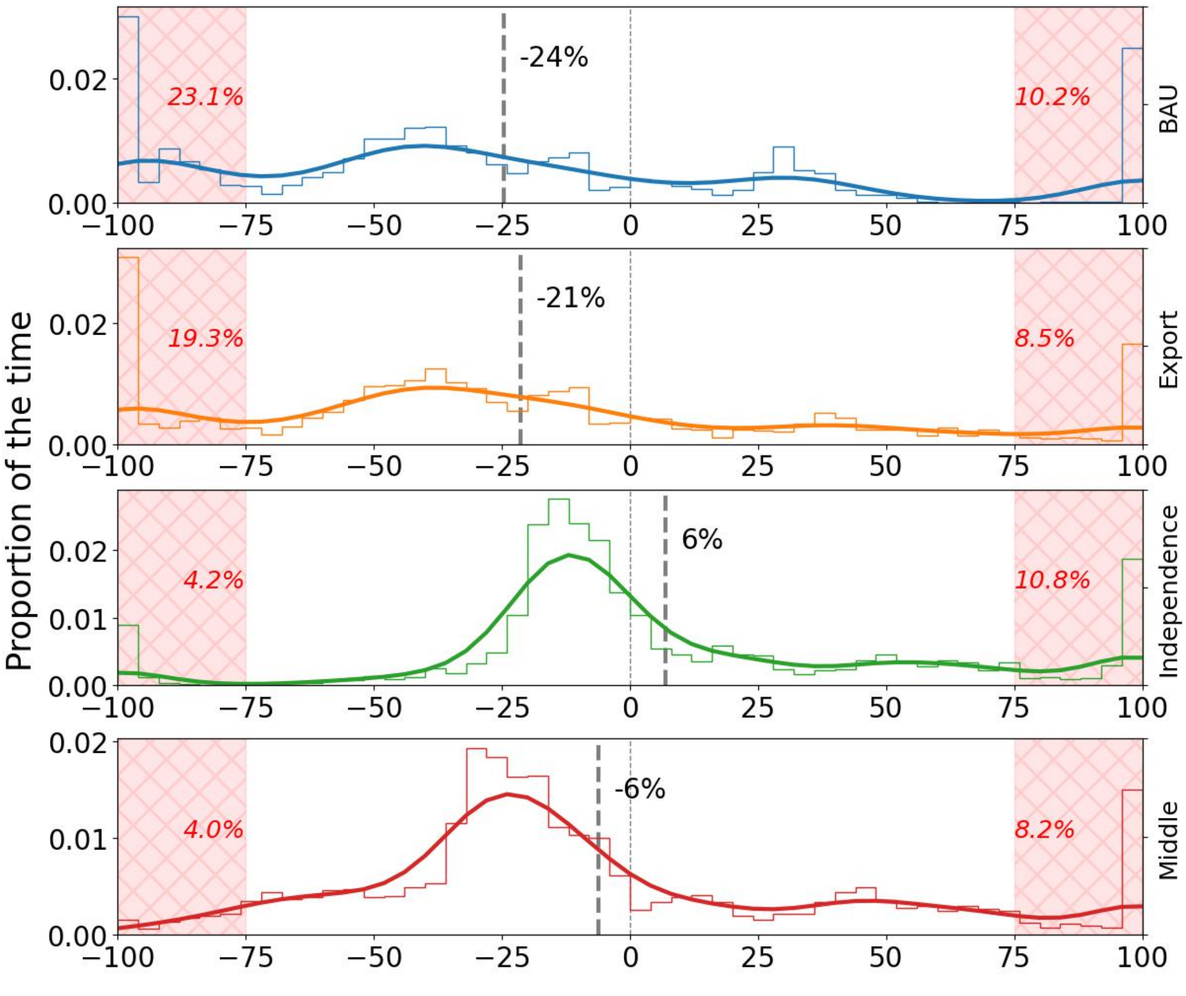

Figure 7-5: Line load for nodes without generation capacity during periods of peak generation on the mainland (defined as whenever the most expensive mainland hydrogen generation is running). Negative load here is defined as electricity imported to the node from the direction of the mainland.

7.3 Non-electrical energy balances: hydrogen, biogas, and heat

For non-electrical energy, hydrogen is assessed first as the second largest energy type. The BAU scenario has no electrolysis, so demand (blue in Figure 7-6) is entirely imported (negative in the figure). Despite upgraded transmission infrastructure, the amount of summer curtailed generation is roughly equal to hydrogen demand. Although offset by electrolyser efficiency, it demonstrates the dual role electrolysis could have in reducing both curtailment and import requirements. Curtailment in the winter BAU scenario is lower at 9% of total generation, but still significant. What electrolysis capacity is optimal given available generation, demand, network capacity, and import costs is one of the key features discussed in assessment of overall system costs (Section 7.4).

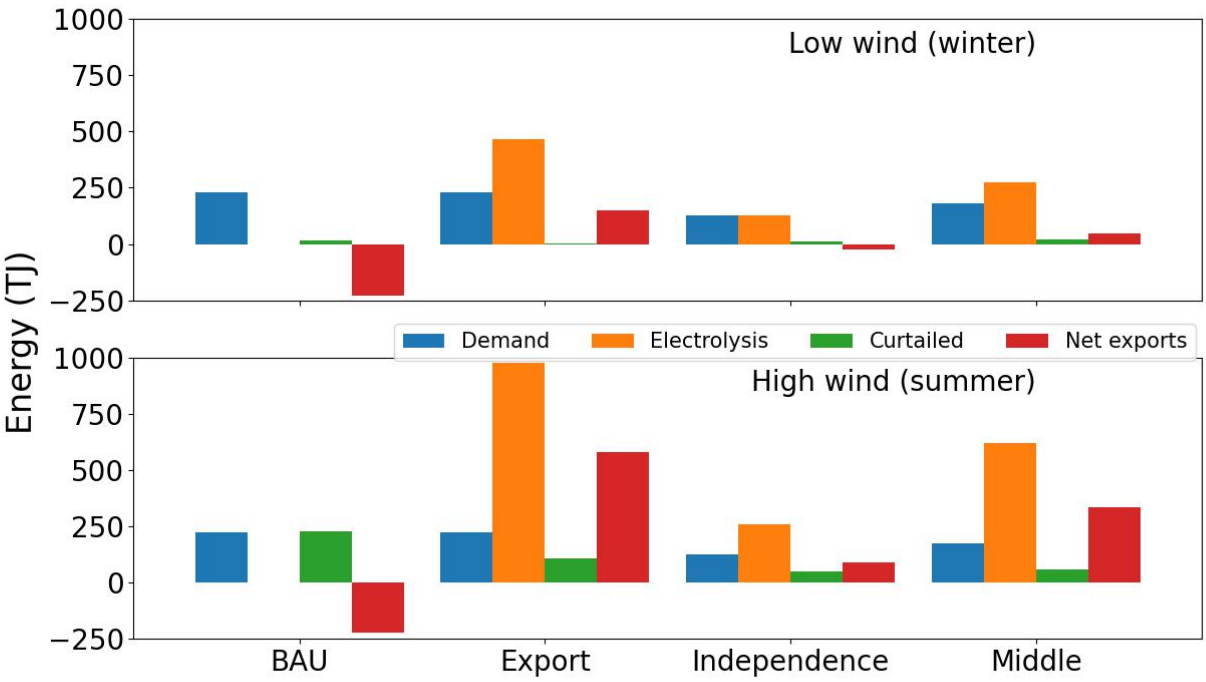

Figure 7-6: Hydrogen demand and electrolysis operation by scenario for both weather periods. Negative net exports (red) denote that hydrogen is imported.

For scenarios with electrolysis capacity, balances vary by weather scenario. In the summer (high wind), local electrolysis exceeds local hydrogen demand, which could then be exported or stored. Essentially in the summer, the relative proportions of supply, demand, and exports are similar between scenarios: both renewable generation and electrolysis exceeds local demand, enabling excess hydrogen production. For the Export and Middle Way scenarios, this is expected given electrolysis capacity is sized to meet average curtailment, which is reduced relative to the BAU scenario where only network capacity is upgraded. However, for the

Independence scenario (sized to meet local hydrogen demand in the winter period), there is still an excess in the summer, highlighting the seasonality of electrolysis being useful as longer-term energy storage. Depending on production in the remaining months of the year, it might be that modelled electrolysis capacity exceeds the islands annual requirements.

For the winter month (worst-case wind drought for the UK), the Export and Middle Way electrolysis capacity can produce hydrogen exceeding local demand. This should however be offset against the scale of local generation capacity which is much higher than local electricity demand without electrolysis. Scenarios have a proportion of local electrolysis to wind generation of 15% (Independence) to 29% (Export), mostly exceeding the 17% modelled for the mainland (24.5 GW electrolysers against 145 GW of wind) (National Grid, 2023). The islands, with limited local demand relative to generation, will likely be able to export more energy than elsewhere. This will however depend on energy market structures - the implications of the proposed LMP (BEIS, 2022i) is discussed in Section 7.5.4. In the Independence scenario though, there is a small net import balance, because generation and electrolysis are not evenly distributed.

This disparity is clearer comparing local authority area hydrogen balances (Figure 7-7, noting the differences in y-axes scales). Regions can be categorised depending on the local generation capacity on the left and right sides of the figure. For lower generation capacity regions, electrolysis more than local demand is possible, but dependent on imports and the capacity of mainland interconnections rather than availability of local curtailed wind. This is demonstrated by the Independence scenario producing proportionally the same excess hydrogen as the Export scenario, despite having much lower electrolyser capacity. This highlights potential synergies between electrolysis, efficiency, and flexibility, which appears to free up more electricity to produce hydrogen. As the cost of green hydrogen is highly dependent on the load factor (BEIS, 2021a), greater efficiency would have a significant effect on the cost (discussed in Section 7.3.2).

For the regions with higher generation capacity, local hydrogen production can more easily exceed local demand. The Export summer scenario could produce up to 5.3 times local demand, whilst reducing curtailment 39% from the BAU scenario (which uses only interconnections to reduce curtailment). If this scenario were technically feasible (steps to realise scenarios are discussed in Section 8.4), then it implies that electrolysis should be co-located with generation. Although excess wind is also imported from the mainland for island regions without generation (the left side of Figure 7-7), the potential imports are limited by grid constraints. Again, despite the

Independence scenario capacity being sized to meet winter demand, it could potentially export or store excess hydrogen in the summer period. With adequate storage capacity, this would allow the islands to be more resilient to the extreme weather conditions which will have greater affect on net zero energy systems.

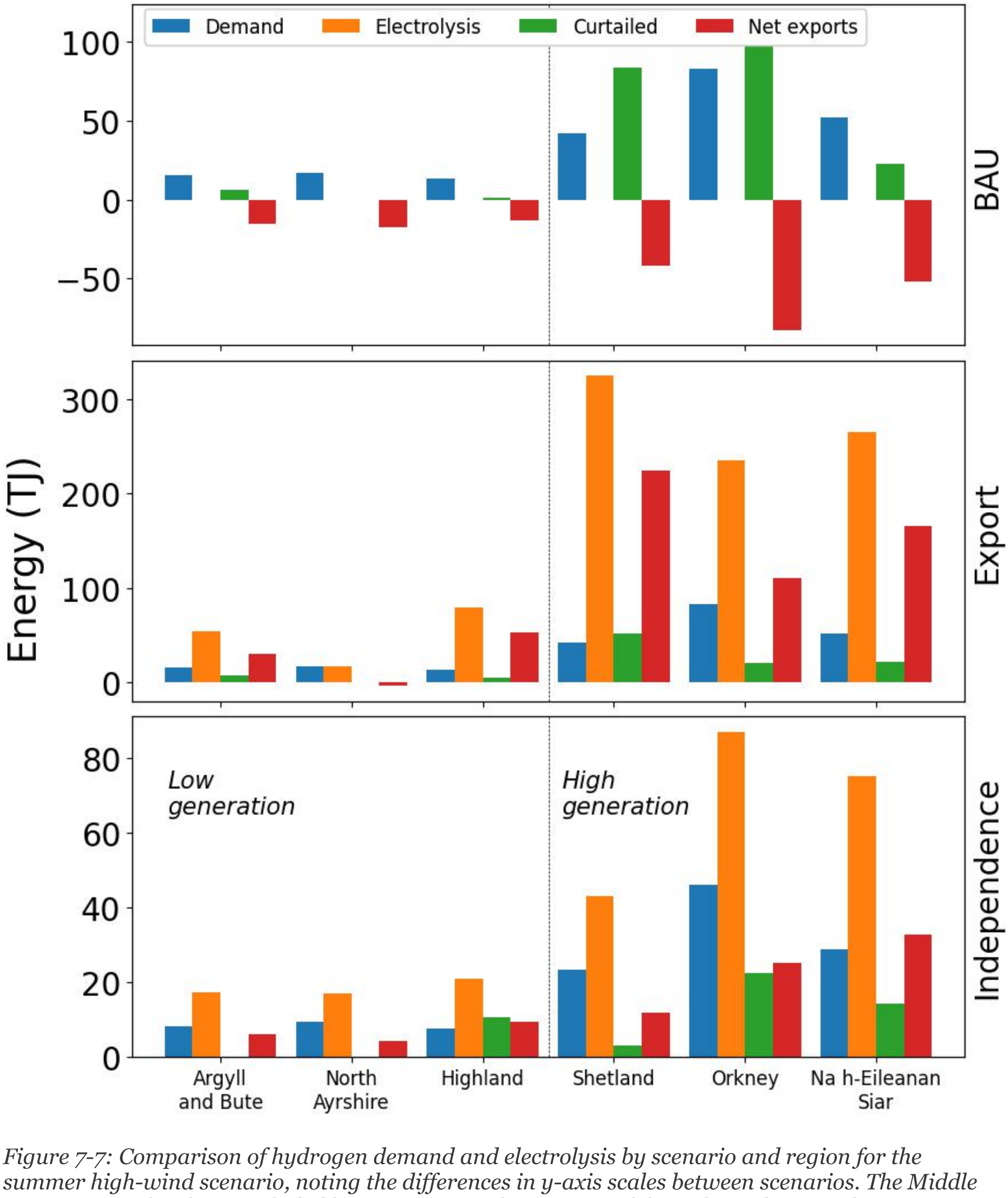

Figure 7-7: Comparison of hydrogen demand and electrolysis by scenario and region for the summer high-wind scenario, noting the differences in y-axis scales between scenarios. The Middle Way scenario has been excluded here as it is just the average of the Independence and Export scenarios.

7.3.1 Hydrogen storage capacities

Estimated hydrogen storage capacities (Section 3.4.2) can be compared (Figure 7-8). These are calculated based on the storage requirements needed to meet local demand considering local electrolysis (i.e. imports or the total winter demand less local production) and the size needed to store excess hydrogen produced (i.e. the total produced in the summer above local demand). The suitability of either option will depend heavily how hydrogen markets develop, which as discussed is uncertain. It is assumed that for the BAU scenario, there would be a market for hydrogen as a commodity which could be transported to the islands; the other scenarios assume a supportive regulatory and policy environment for small-scale electrolysis. Implications for this are discussed in Sections 7.5.1 and 8.2.3.

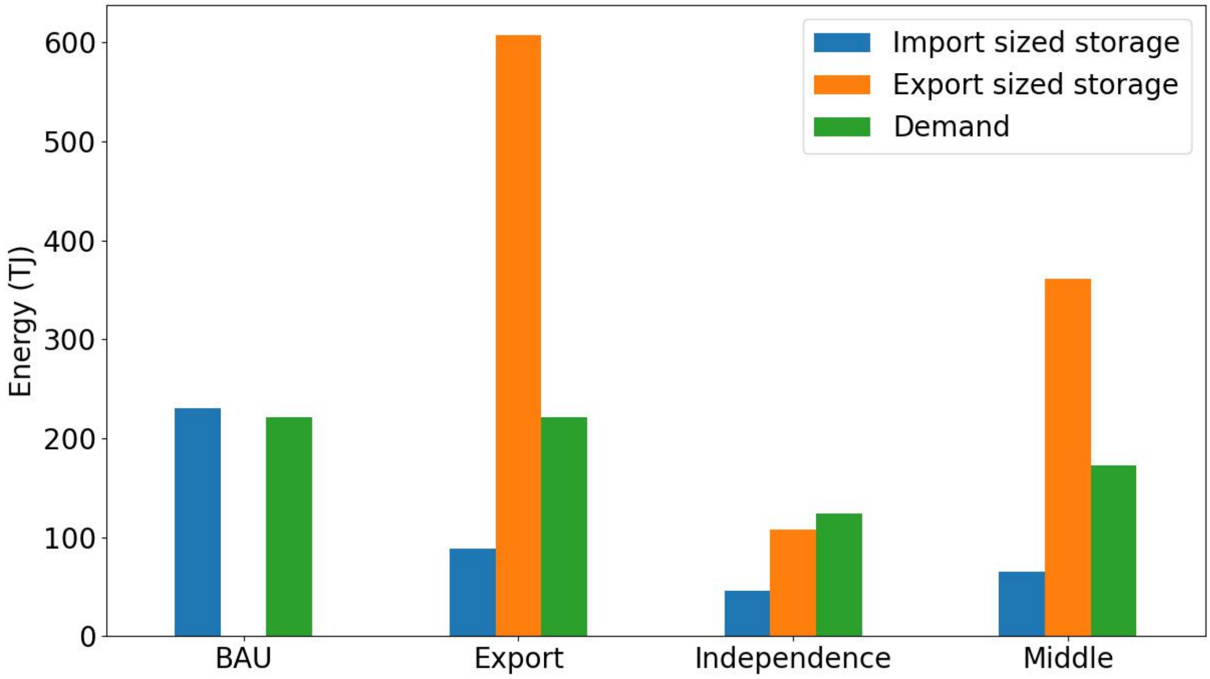

Figure 7-8: Hydrogen storage requirements, noting that import-sized storage is calculated from the winter scenario (when demand is higher and supply lower) and the export-sized storage is calculated using the summer scenario (when demand is lower and supply higher).

Without electrolysis, the BAU scenario is entirely dependent on storage. The other scenarios storage requirements are 62-80% lower due to electrolysis and reduced demand (Independence and Middle Way). For these scenarios, storage size equals 36-38% of monthly demand, or about 11 days worth. The FES assumes hydrogen storage equivalent to approximately 44 days worth of averaged annual demand for the whole UK (National Grid, 2023) (which could be less if winter demand is higher). The margin of safety with respect to the hydrogen storage capacity (e.g. the amount of fuel required in the event of non-delivery or electrolysis capacity breaking down) would depend on the site-specific context, the criticality of the hydrogen supply to business continuity, and the cost-benefit of additional storage costs. It is not clear what margin of safety would be suitable, so this has not been included in calculations of storage sizes, but it highlights the relative reliance on imports between scenarios. It does denote that storage capacities and costs here are a lower bound, which is discussed in Section 7.4.1.

The Export scenario has the largest export-sized storage requirements - more than three times greater than local demand. Although the Independence electrolysis is sized for winter demand, the summer can produce almost as much again that could be exported or stored. The cost of storage and implications for the type of hydrogen fuel or electrolysis technology could be suitable are discussed in Section 8.2.3.

7.3.2 Electrolysis load factors and ramp rates

Load factor and ramp rates are two key characteristics of electrolyser technologies that affect the cost of hydrogen and the technical suitability of different electrolyser technologies (BEIS, 2021a). An average of three technologies was modelled - alkaline, proton membrane exchange, and solid oxide electrolysis. The model only considers the efficiency as a technical constraint to simplify the number of scenarios, but results can be interrogated for specific technology implications.

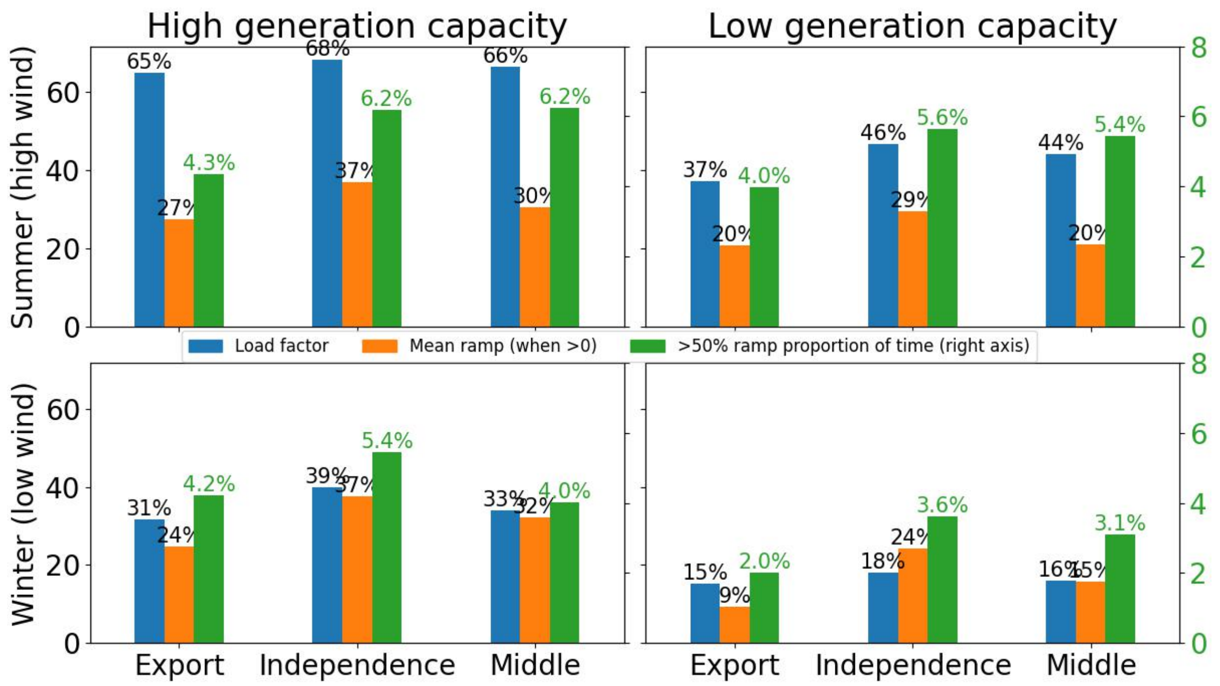

Figure 7-9: Average load factors, ramp rates, and proportion of the time the hourly ramp rate exceeds 50% of the maximum capacity by scenario and regions (see Figure 7-7 for classification; y-axis is in green on the right).

For regions with higher generation capacity (Figure 7-9), modelled load factors of up to 68% in the summer, and 48-54% in the winter average greatly exceed the 25% assumed in BEIS hydrogen cost estimation (BEIS, 2021a). This indicates the electrolyser capacity could be undersized based on either modelled demand or curtailment. Whilst it could also be a symptom of an over-exaggerated peak wind production (identified in Section 6.2.1), this is unlikely to entirely explain the more than double difference between the BEIS assumptions and results. For regions with lower generation capacity (right side of Figure 7-9) the difference with the lower capacity factors of 26-32% could be attributable to the over-predicted peak wind generation due to dependence on mainland electricity imports.

The Independence scenario has the highest load factor for both weather conditions in High and Low generation regions. This could be due to several factors, which would require further work to isolate. It could be that having the lowest demand and highest flexibility increases the availability of curtailed wind for electrolysis. Alternatively, the electrolysis capacity in proportion to generation capacity is lowest (14.9% in Independence, 24.7% in Middle, and 29.8% in Export), which would also increase the load factor. The effect of these can be interpreted through the different generation and weather scenarios. In the summer, areas with high wind differ in load factor by approximately the proportions of electrolyser to generation (with the Middle Way scenario 66% being closer to the Export with 65%), indicating that at peak wind production, this has a greater effect on the load factor. However, in the same weather but areas of low generation, that the Middle Way scenario has a much higher load factor (44% compared with 37%), indicates that reduced demand enables higher load factors. Irrespective of electrolyser technology, higher load factors will reduce the cost of hydrogen production.

Ramp rates are also consistently much higher in the cases with higher load factors, which does have specific technology implications. Average ramp rates are 10-13% higher by scenario with increased load factors. While the average ranges are within the limits for each technology, the proportion of the time with ramp rates >50% could be more problematic for solid oxide electrolysis, which has lower maximum ramp rates than particle exchange membrane or alkaline (Martinez Lopez *et al.*, 2023). Feasibility of these results will depend on electrolyser economies of scale and other hydrogen assumptions which are discussed in Section 7.4.

7.3.3 Scope of water stress from electrolysis demand

Water demand for the islands (Section 4.1.3) can be compared against electrolysis water demand (Figure 7-10). It shows, that although electrolysis water demand is notable at up to 12% annually and varies by scenario, the amount should be manageable relative to current capacity. Other factors, such as managing grid constraints (Section 7.2.1) are more likely to be a limiting factor and is addressed in Section 8.2.3.

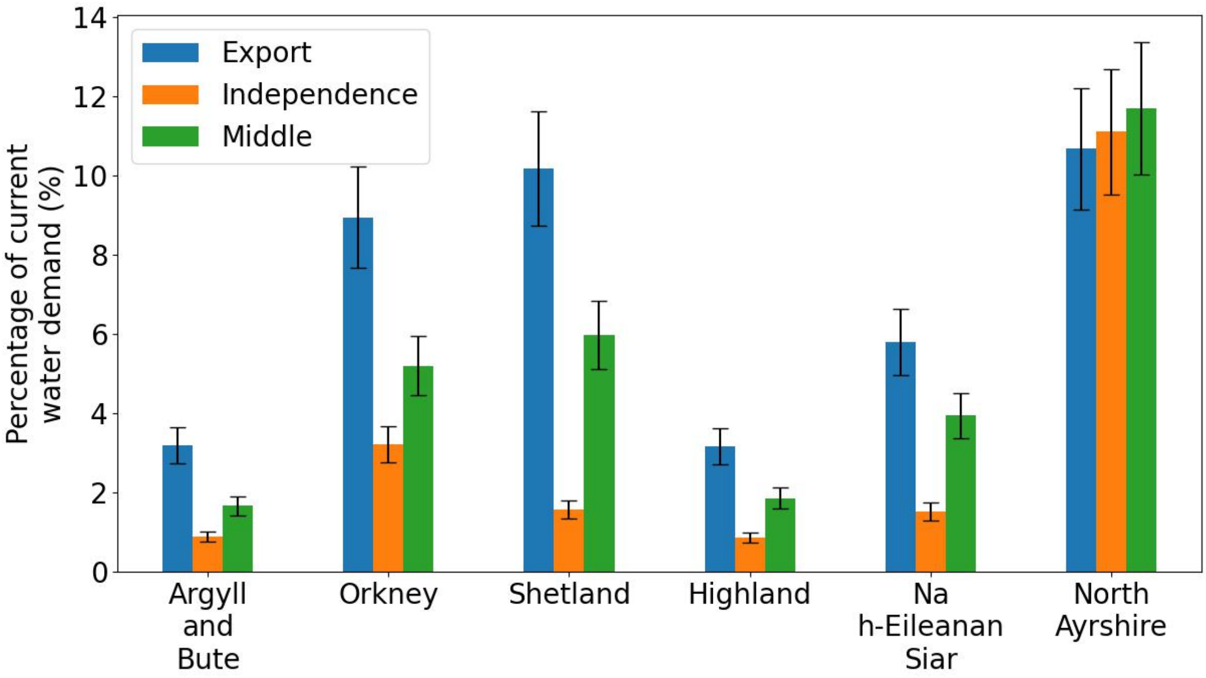

Figure 7-10: Proportion of current (2018-19) annual water demand (Scottish Water, 2022a) *required for hydrogen electrolysis, assuming 330-440L/MWh* (Rushton-Smith, 2023).

7.3.4 Biogas and heat balances

Comparing regional industrial heat demand, biogas, and hydrogen balances for the Export (hydrogen only) and Independence (hydrogen and biogas) scenarios in the winter highlights the potential for biogas in more detail (Figure 7-11, noting the different y-axes). For Export, higher generation areas can produce hydrogen much more than local demand, however areas with less generation are unable to meet local hydrogen and heat demand. Particularly in Argyll and Bute, the concentrated whisky heat demand (Section 5.6) exceeds the local capacity for electrolysis based on local curtailment. This is masked in the whole island results (Figure 7-6) by the excess generation elsewhere (right side of Figure 7-11). This implies electrolysis capacity should be co-located not just with demand, but also generation (unless grid capacity is under-utilised - which could be less likely after demand electrification). Improving biogas utilisation in regions with lower generation potential (due to concerns about landscapes or protected areas) could therefore be more beneficial if local electrolysis would also have lower load factors.

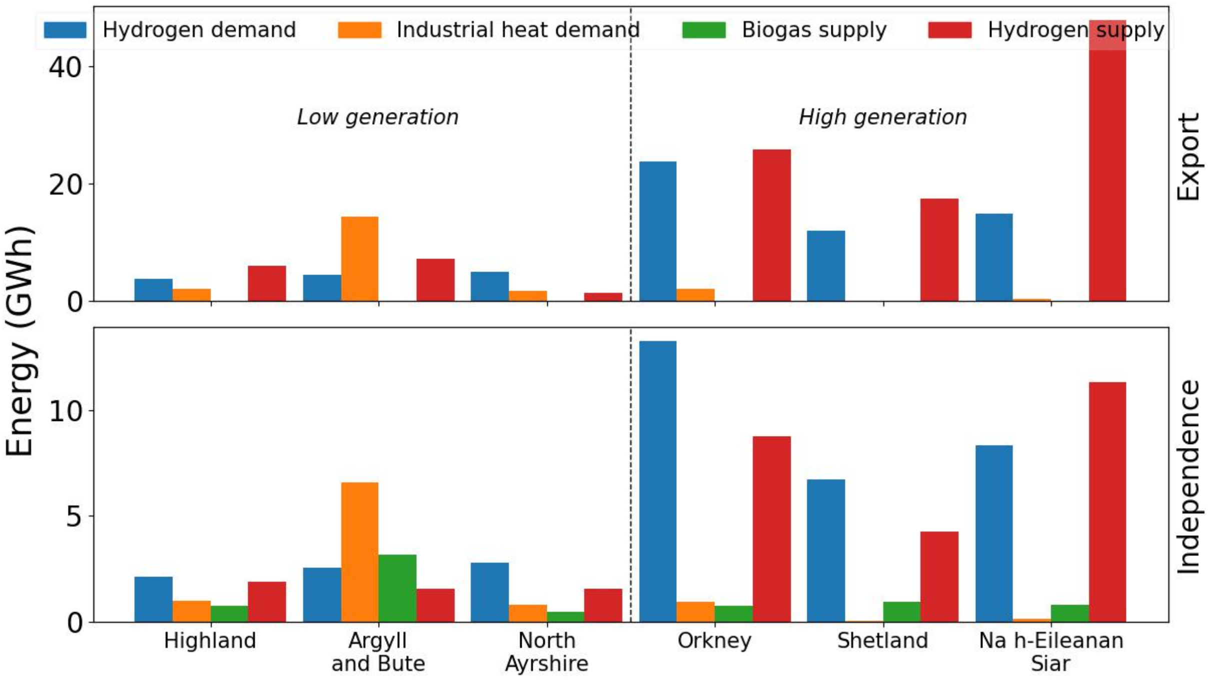

Figure 7-11: Comparison of regional industrial heat demand, biogas supply, and hydrogen availability for the Export and Independence scenarios during the winter month. BAU is excluded due to relying entirely on imported hydrogen (shown in Figure 7-7) and Middle Way is the average of the two shown here. Note the differences in y-axes between the two plots.

The role of biogas in the Independence scenario is more prominent in regions with less potential for renewable and electrolysis capacity. In the Highland, North Ayrshire, Orkney local authorities, biogas could help meet greater heat demand. In Argyll and Bute, it could meet approximately half of heat demand (combined with industrial efficiency improvements - Section 4.6.5). The main difference though is that Argyll and Bute have a high industrial demand (distilleries) relative to a smaller local population, whereas other regions have biogas potentials much less dependent on industry (i.e. higher food waste or farming), hence a higher proportion of biogas potential relative to the industrial heat demand. The cost of energy from biogas (Section 5.6) with industrial biowaste only could in some cases be reduced with additional domestic and commercial waste streams included. This is reinforced by energy balances here, as industrial heat demand could be entirely replaced by biogas if all potential biowaste (not just industrial) is utilised. As also determined in Section 5, biogas would appear to have the greatest potential in industrial applications for the islands, but this could be supplemented by additional waste streams from other sectors as shown by the split between regions in Figure 7-11.

7.4 Comparing the distribution of system costs

Ultimately, the cost of net zero will, to some extent, need to be borne by everyone - as well as being enabled by private finance. Whilst net zero systems could result in lower costs in the long run, the capital-intensive nature of the change in technologies required will likely mean higher costs in the short term if the external costs of climate change are not factored in (CCC, 2023). This could be directly paid by households; through businesses passing on costs to consumers; through network operators collecting regulated revenues from suppliers or bill-payers; or as tax-payers (Institute for Government, 2021). What differs though is how these costs are distributed. Paying for something through increased electricity bills is regressive, whereas taxes are progressive. This means that the relative burden of the bills is much heavier for lower income households than taxes (IEA, 2017). Similarly, those able to invest in different technologies will likely receive the benefits. Different balances of these costs and benefits are not intrinsically better or worse but understanding their structure could help analyse the implications for net zero and how different stakeholders might support changes that will be required. Before examining the economic balances of net zero for the islands, several caveats should be stated:

(i) Costs for some technologies are currently highly speculative, particularly hydrogen due to lack of demonstration at scale. While it seems that hydrogen-based fuels are likely to have a key role in decarbonising demand sectors which technically cannot be electrified, how these fuels are produced and in what form is less clear. The two major approaches (green - produced from low-carbon electricity; and blue - produced from fossil fuels and CCUS) are not mutually exclusive, but the national and international scale of each will affect costs and is considered in the uncertainty of modelled costs.

(ii) Scenario costs are not directly comparable due to outcomes varying significantly. The structuring of each scenario reflects differing distributions of economic and technical aspects which cannot be compared through per capita or per unit cost metrics. Loosely grouping whether costs are recovered through electricity bills, taxes, or directly has implications for the distribution of their recovery. Additionally, some costs are effectively shown twice - e.g. the cost of producing hydrogen from the perspective of suppliers vs. the price paid by consumers for energy.

(iii) Costs have only been presented as the total CAPEX and annual OPEX, which does not consider the time-value of investment. Whilst this might make

comparison of scenarios clearer if condensed into a single figure, it would also obscure the distributional aspects of the costing exercise. In any case, different technologies deployments would likely happen at similar rates between scenarios - e.g. heat pump deployment spread over each year until 2045, with hydrogen technologies more concentrated in the years closer to 2045.

(iv) Only direct costs and incomes from the Net Zero model are considered - other benefits, such as the multiple benefits of energy efficiency (Section 4.7), environmental impacts, or local job creation, are not quantified here. These are discussed in Section 8, but further work would be needed to quantitively incorporate these indirect aspects into this section.

(v) Island results are illustrative but not indicative of net zero costs for the whole UK. The islands have very small populations relative to UK-wide proposed renewable capacities, with about 14.0-24.0 kW of generation per person, whereas by 2050 the whole UK could have a population of about 68 million and a renewable capacity of 137-236 GW (National Grid, 2023), or 2.0-3.5 kW per person. This difference in generation relative to population (which scales demand side costs but also the cost of energy) is considered in generalisation of island results (Section 7.4.3).

(vi) Estimates of energy savings assume that behaviours do not change with changing technologies and efficiencies. This is not necessarily observed (see introduction of Section 4) and will likely exaggerate the potential energy saved from efficiency improvements.

7.4.1 Costs by sector

Costs are grouped into four categories, indicating from whose perspective the cost would be initially incurred (Figure 7-12). Demand and Fuels represent households, businesses, and industry directly through the cost of building upgrades or payment of bills; Supply covers the energy producers, generators, and operators; and Networks is network operators. Depending on the levels of government policy support, all might be supported by taxpayer-funded subsidies. This essentially makes Fuel costs the same as the Supply group, but from the perspective of consumers based on average fuel prices (Section 3.6.4) rather than the cost of energy produced. The total column is not shown in the OPEX plot to reflect this.

The most significant CAPEX categories by scenario are generation and network upgrades (BAU scenario only). Generation is around half of total CAPEX in each scenario. Between the BAU and Export scenarios (identical generation capacities) the difference in Generation costs (Figure 7-12) with the Independence scenario is evened out by additional distributed generation (in the Demand category of Figure 7-12).

Network upgrades have by far the greatest single cost but also the greatest uncertainty bound. The nodal model structure cannot identify specifically which lines would need upgrading (Section 3.6.3), other than the bare minimum of lines that connect nodes highlighted as constraints in the ANM systems. At the upper end, given the large uncertainty around the assumptions used to calculate this (such as not including unserved energy affecting network upgrades - Section 7.2.1), the real cost could be much higher.

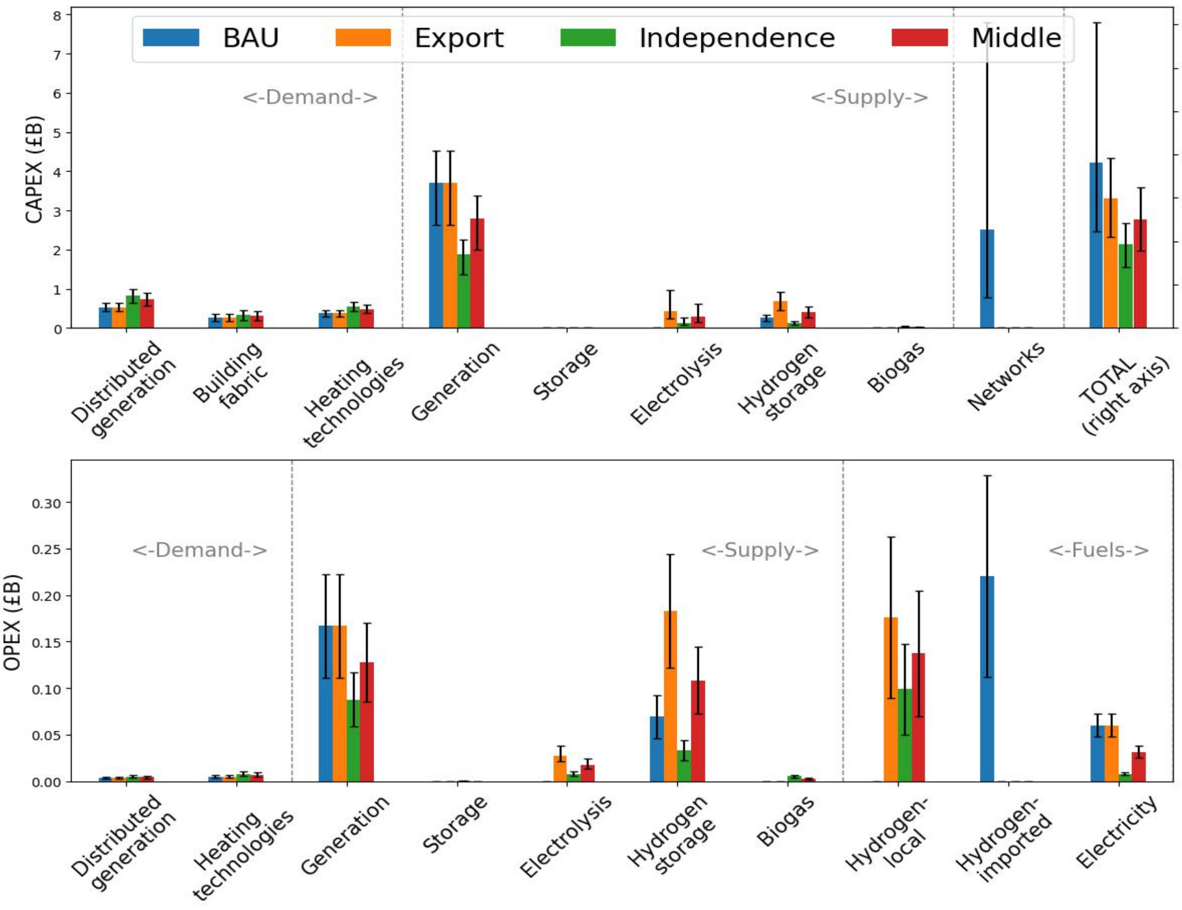

Figure 7-12: Costs by sector (demand, supply, networks, fuels, and total - separated by dashed lines) and subsector. Error bars denote the variation between the modelled high and low-cost estimates.

The scale of overall hydrogen costs highlights the challenge of replacing fossil fuels for non-electrified sectors. More regular fuel imports or cheaper geological storage options (Section 3.4.2) are unavailable for the remote islands, so reliance on compressed or liquified (as modelled) storage is more expensive. Modelled storage sizes do not include a safety margin (assuming the weather conditions would be worst-case for the islands), so the actual costs could be several times higher. Coupled with the fact that imported hydrogen has been modelled as 25% more expensive than on the mainland to capture additional transportation costs (Section 6.1.1), this indicates that (without unabated fossil fuels) it would likely be more cost-effective to first either reduce demand or use alternatives such as biogas or heat pumps.

The greatest cost categories highlight areas where alternative solutions could be more cost-effective. The significant upper bound of the network costs (combined with reduced fuel costs for the islands) supports demand-side measures being a better investment from an overall cost perspective. Similarly, potential costs for biogas (as the most cost-effective configurations on the islands - mainly industrial locations in Section 5.6) are an order of magnitude lower than other supply side costs. For the BAU scenario, with the highest share of biogas investment, it makes up 2% and 4% of the Supply grouped CAPEX and OPEX respectively but could contribute up to 7% of the islands' total energy demand in the BAU scenario (or 5% in BAU or Export scenarios with reduced demand efficiency investment). This suggests that biogas could form a cost-effective part of a net-zero energy system, particularly for the islands where hydrogen storage and import costs are much higher than the mainland.

7.4.2 Balance of annual costs and incomes

Looking at the balance of annual OPEX and income generated by energy produced on the islands (Figure 7-13), the distribution of expenditures can be compared. The balance is shown for the whole islands, with costs split into groups of which party would be responsible for them. The total does not imply that the net cost or benefit remains within the islands but indicates the distribution between scenarios.

Looking at Demand (green, but barely visible) and Supply (purple), the OPEX required is of a different order of magnitude. The outcome is clear. Looking at the fuel costs (orange) - efficiency improvements combined with DSR, local BESS, and distributed generation mean consumers could pay dramatically less between the BAU and Independence scenarios. The modelled total paid for electricity is just 13%, which although as described in Section 4 is likely an optimistic lower bound, highlights the maximum potential.

Difference between the two scenarios also highlights the different distribution of expenditures. In Independence, costs to reduce demand would likely be borne by households and businesses, which might be directly supported by government subsidy (likely for the greater CAPEX than the OPEX shown here - see Figure 7-12), but they would also receive the benefits of reduced bills, in addition to other multiple benefits not modelled, such as warmer homes and health outcomes (Citizens Advice, 2023). Conversely in the BAU scenario, the greater generation and fuel import costs would be borne by developers and operators, with correspondingly greater incomes due to lower investment in efficiency, resulting in higher bills than the Independence or Middle Way scenarios.

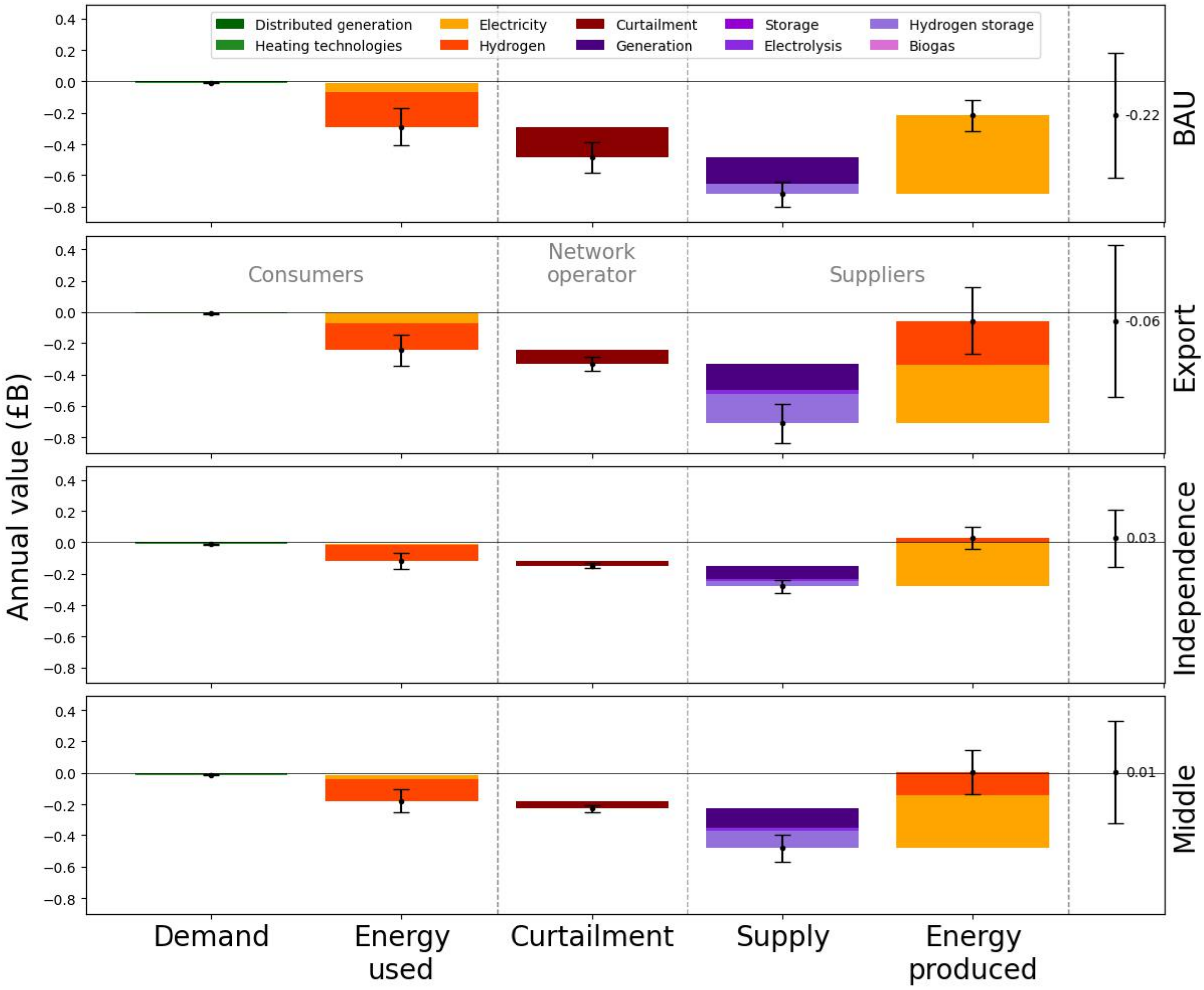

Figure 7-13: Annual costs (negative) and income (positive) for the islands, with error bars for the range of high and low costs. Note that energy produced shows the value of exported energy (i.e. total generation less demand). The rightmost error bar shows the potential range for the inverse of high-low costs vs fuel prices.

Even with expansion in the BAU scenario of the transmission system the cost of curtailment in this scenario is £98-294 million per year at current curtailment prices (Section 3.6.4). This is approximately equal to the difference between the average net balance, which is negative, indicating that overall energy costs on the islands would be more favourable with minimal curtailment. Electrolysis in the Export scenario (the only difference with the BAU scenario) clearly helps in this regard, but the combination of electrolysis and demand side measures in the Independence and Middle Way scenarios has a greater effect. Curtailment costs at this scale could make the modelled scale of generation unfeasible depending on criteria used to assess its development.

Inverse combinations of high-low costs and income are shown on the right of Figure 7-13. This illustrates the case if estimated costs were low but income from energy sold (i.e. fuel prices) was high, or vice versa. This could depend on market fluctuations such as international hydrogen prices. BAU and Export scenario balances have the widest range due to being more dependent on energy prices. Despite BAU exporting 78%

more electricity than Independence, the maximum potential positive outcomes are similar. With the greater BAU exposure to electricity prices though, the potential lower bound is three times lower. Although the potential upside is highest in the Export scenario with lower curtailment costs and higher share of hydrogen income, the spread in Independence is lowest. This indicates that under the great uncertainty and potential outcomes in reaching net zero, the combined approach with a greater commitment to distributed and demand-side technologies could provide greater resilience.

7.4.3 Demand costs scaled to mainland proportions

The islands have a proportion of proposed renewable generation relative to the population roughly 4-12 times greater than the mainland. This has the effect of lessening the scale of demand side measures relative to the overall investment. To better compare the trade off between the scenarios on similar scale to the mainland, the costs which are directly proportional to the population (demand, biogas, and the cost of energy used) have been scaled by factors of 4 and 12 (Figure 7-14).

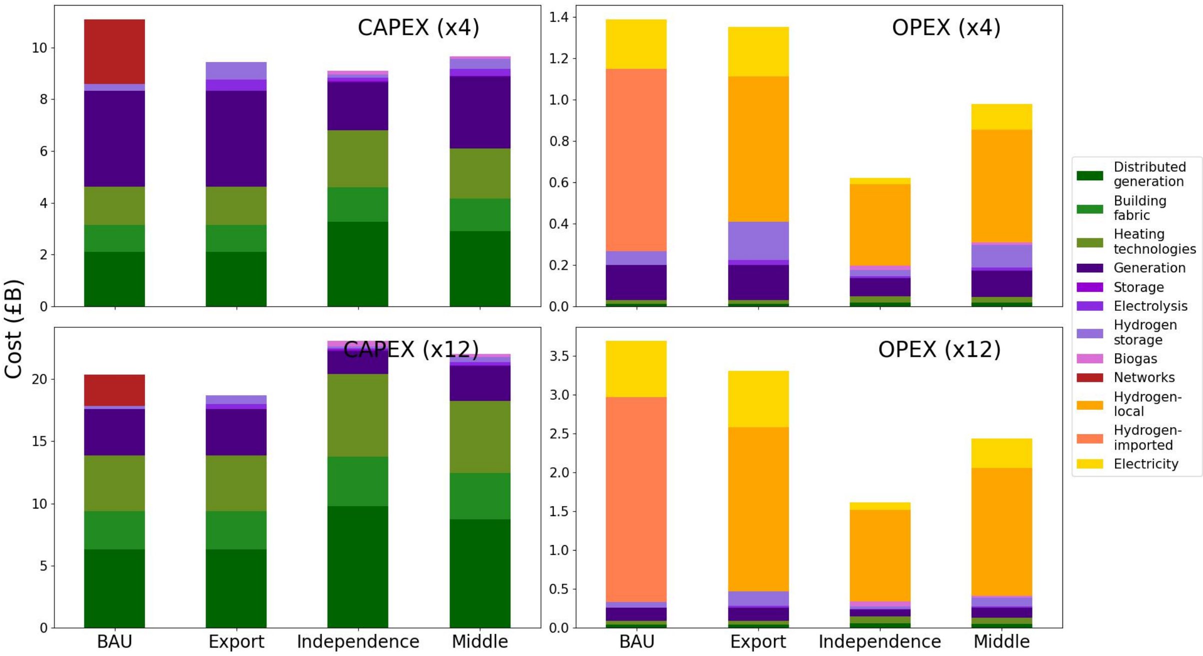

Figure 7-14: Mean costs where costs for demand (green), biogas (pink), and energy used (orange) are scaled by 4-12 times (labelled on each graph) to match the proportions of the mainland population - see the introduction to Section 7.4.

Relative to the mainland, this will likely understate the scope of supply side costs due to only onshore wind being modelled for the islands (e.g. excluding balancing costs or more expensive generation such as BECCS or nuclear). Similarly, network costs have not been adjusted as the proportionality to population is less clear than in demand costs. Depending on the scaling, the Independence scenario has either the lowest or highest CAPEX, but in all cases the lowest OPEX. The difference in OPEX for the BAU and Independence scenario of £2.2B per year means that in just a few years the difference in CAPEX costs is covered. Additional uncertainty in fuel prices and network upgrade costs could make the Independence scenario much more cost-effective overall, but extrapolating this analysis to the wider UK is highly speculative.

7.5 Sensitivity of results to major assumptions

Results have been described in this section as the outputs of the net zero model in PLEXOS. Like any model, this requires assumptions to simplify the computational complexity of the problem and reduce uncertainty in aspects which cannot be accounted for. The assumptions used for this model were highlighted in Section 3.5 and have been mentioned briefly in the preceding Sections of Chapter 7. This section will now address how sensitive and robust the results are to these assumptions.

7.5.1 Hydrogen technology assumptions

As discussed, uncertainties for hydrogen in the model are perhaps the greatest. This section deals with technical hydrogen assumptions (excluding demand, discussed in the following section)– assumptions about prices and market structures are described in Section 7.5.2.

For simplicity, hydrogen has been used in this work as a very broad term, which could include a range of fuels. It is assumed that green hydrogen produced by electrolysis would be the basis of these other fuels (such as ammonia), therefore producing hydrogen would still need to be the first step in producing them. It could be that other sources of hydrogen were available, but they would be unlikely to be produced on the islands. Converting pure hydrogen to other fuels incurs an efficiency reduction which might make production on the islands less attractive to produce it, but this might be offset by the reduction in transportation costs that a non-gaseous fuel would have. If the capacity factors modelled of more than 31% in the worst-case winter month were achievable, then the price of hydrogen could be sufficiently low enough to offset the costs in conversion to another fuel type. Further economic modelling would be needed to understand this trade-off, which is discussed further in the following section. An alternative case that could occur is if blue hydrogen is more successful than green (e.g. oil and gas producers can successfully transition to CCUS). This could facilitate cheaper low-carbon fuels that would be much more suitable to store and transport to remote regions than pure hydrogen. This however would not have the additional benefits green electrolysis could have in reducing curtailment, demonstrated in the results, which could be supported through policy in other ways such as participation in balancing markets.

Results highlighted how hydrogen storage costs were one of the highest categories of costs (also with the greatest uncertainty, which does not capture this trade-off between efficiency and costs), which would indicate that there is likely the greatest scope for improvement through other technology types that are not captured by this simplification. Other technology types could emerge that would be cheaper or more practical - as or when hydrogen starts to have a more stable role in decarbonisation plans. Given the remoteness and relatively low demand of the islands, it seems unlikely that the cheapest method of transport, a pipeline for import or export, would be developed for any of the regions. The modelled difficulty and high cost of storage and therefore transport to the islands highlights issues with pure hydrogen being a viable fuel source for remote communities. Without natural gas infrastructure or cheaper options emerging, they would be dependent on more expensive storage technologies such as the liquefied type modelled here. As the model does not capture technology switching where it might be less economical than alternatives, it highlights that perhaps other fuel types could be more suitable.

That hydrogen production is viable for the islands is also highly dependent on the assumption that there is a business-case for it. Investment in the technology would require coordination of supply and guaranteed demand to purchase the fuel. Local government planning would need to be supportive of developments, which as shown in the LDPs for each local authority (used as a constraint of the electrolysis and BESS capacity per node- Section 6.4.3) varied significantly. The economics of hydrogen production for remote communities would also need to be positive, which as discussed will take much more work to become clear. Obviously without any of these conditions for success, electrolysis for the islands would be unlikely to be viable. Again if this were the case, it would further support the need for other means of local flexibility to help reduce curtailment and manage the variability of renewable generation (Figure 7-4).

7.5.2 Demand modelling and rebound effects

The literature highlighted that the demand model could overpredict energy savings due to the rebound effect (Section 4.8). The demand model has been set up such that there is no modelled change in behaviour (save for a modest change in transport usage with increased public transport- Section 4.6), but this does not mean that behaviour would not change under different efficiency scenarios. Where identified, efforts were made to make sure that the model captured the savings which could be lower than expected, such as through the heating model being calibrated using recorded heating demand classified by EPC rating (Section 4.2.4).

However, the potential impact of the rebound effect should still be considered. This can be assessed through calculating the size of rebound effect required for the overall cost balance of scenarios from Figure 7-13 to be equal (Table 7-2). This simple analysis only accounts for the rebound effect for each specific scenario when it would also occur for the one compared against. It demonstrates the percentage rebound effect required to alter the ordering of results regarding changes in annual costs. For example, if the actual savings were 87% less than modelled here, the Independence scenario would be breakeven with the BAU scenario in terms of the annual bill savings. At an economy-wide level, the rebound effect has been estimated as up to 10% for transport and up to 30% for heating (UKERC, 2007). Values greater than 30% are in bold in Table 7-2 to indicate where the cost differences between scenarios is more robust to the demand excluding the rebound effect. The Independence and Middle scenarios, with the greater efficiency investment are more robust to underestimated savings and could still be more cost-effective relative to greater fuel price uncertainty (Section 3.4.1 and 3.4.2).

Table 7-2: Size of rebound effect required for the scenario in the top row to match the total shown in Figure 7-13 for the scenario in the left column. A negative rebound here indicates that demand would increase by the amount shown. Omitted values were >100%, e.g. demand of zero would still not breakeven with the indicated scenario - other savings would be required.

%	*BAU*	*Export*	*Independence*	*Middle Way*
BAU	0	**-57**	**-87**	**-79**
Export	**68**	0	-**35**	-26
Independence	**-**	**78**	0	20
Middle Way	**-**	**37**	-13	0

The deterministic nature of the scenarios has meant that fuel switching due to energy prices is not modelled. In this respect, the assumption that all demand less likely to be electrified would be replaced by hydrogen could bias results towards supporting hydrogen. The reality would depend on the relative prices of hydrogen and other alternatives, which for the most part given the nature of demand on the islands would be electricity. For example, high-temperature industrial heat pumps could be suitable for distilleries, or electrified ferries. The focus of the demand model was in demonstrating the potential for time use survey and synthetic populations to represent behaviour in energy demand, but this has precluded more detailed work in modelling alternatives for the heterogeneous sectors of industry and heavy transport. Furthermore detailed work would be needed to understand the more technical, industry-specific technologies, their comparative costs, and how suitable they might be for the region.

If these sectors were suitable for electrification, localised electrolysis would be completely unviable (the alternative case that hydrogen based fuels were available much more cheaply than could be produced locally is discussed in the following section) unless exporting from the islands were viable due to sufficient demand in a regional market and a competitive price was achievable. This could be achieved if greater capacity factors were to reduce hydrogen prices enough and transport costs were not too great (discussed in the following section). Without electrolysis, curtailment in all scenarios except the BAU would be increased significantly, but to a lesser extent in the Independence scenario due to the greater focus on demand and flexibility. Although higher rates of curtailment are not necessarily a problem in achieving net zero, if they are too high, they indicate where the design of energy markets could reduce prices depending on curtailment prices. If electrolysis is not viable as a flexible demand to reduce curtailment, then this should reinforce the case for other methods of flexibility which are key to maximising utilisation of renewables.

7.5.3 Supply, network, and biogas issues

To simplify scenarios and improve model run-time, representation of the mainland was simplified relative to the validation model (Section 6.2), with one node and scenario of supply and demand. As the maximum generation capacity required is dictated by demand, if mainland demand was altered, the result would likely be similar for the islands for the modelled extreme weather periods. In terms of generation, an average of the two extreme generation scenarios was used from the FES, which could be wildly different from what it looks like by 2045 (recall the difference in generation capacity between the 2019 and 2023 FES in Figure 2-2). It assumes a seven-fold increase in wind capacity, with a significant proportion of BESS, DSR, and V2G (National Grid, 2023). The aspect of this that could have the greatest effect would be the scale of wind generation and its location. With a lower proportion of wind on the system, curtailment would probably be lower for the islands due to less total wind on the system increasing the price received by generators. This could make the scenarios involving electrolysis less attractive due to having lower capacity factors. Conversely, with more wind on the system, there would be more opportunity to import wind from the mainland which could be used to produce hydrogen in periods of low generation for the islands (subject to the main issues discussed for hydrogen). Much of this though would depend on the issue of network constraints on the mainland.

Simplification of the model excludes mainland transmission constraints, which are already a limiting factor for generation in northern Scotland. This would result in higher curtailment of renewable generation at times of peak generation but given the location of the island wind at the extremities of the UK network, excess generation on the mainland would be less likely to coincide with peak generation on the islands (Matthew and Spataru, 2021). This could lower the disruption to island generation, but the extent to which this occurs would depend on the correlation between generators and the effect of grid constraints. If at the furthest extremity of the UK network island generation would be sooner constrained than mainland capacity, then the curtailment modelled here could be dramatically understated. This assumes that market changes such as LMP were not implemented, as any measures to encourage local energy demand through lower energy prices would help to reduce curtailment- this is discussed in more detail in the following Section. If curtailment here was understated (at an annual average of around 15% for the BAU scenario), it would surely make a stronger case for distributed technologies like electrolysis, BESS, and DSR. This would also depend on how curtailment payments are structured, which could change depending on how much a burden the costs become with significantly more renewable generation on the system. Further work would be needed to compare different representations of the mainland to better understand this effect.

There are also other issues for the simplification of networks. At the larger scale, interconnections with the EU are not modelled, but are likely to play a significant role in decarbonising electricity supply. For the high wind scenario, they could reduce curtailment, but this effect would likely be less significant than the above issue of North Scotland constraints increasing it. In the low wind, it would probably have the effect of reducing the unserved energy in the model given the potential to import electricity, but this effect could be reduced depending how wide-ranging the weather system affecting generation could be.

At a smaller scale, the network model also simplifies local network constraints, which are only captured for the main areas of the regions with ANM schemes (Figure 3-6). This could have the effect of understating local network issues and could mean the estimates of network upgrade costs are understated. If this was the case and more generally for results though, the extensive cost to upgrade transmission and distribution networks would surely encourage alternative and less costly solutions. This could for example include digital technologies to better utilise existing electricity lines though enabling more precise and real-time understanding of capacity constraints (data which the network operator did not have available for the region- Section 6.1.3). Although there is huge uncertainty in the cost results, that network costs are among the highest highlights some of the better scope for reducing overall costs through innovative and smarter alternatives to the historic option of just expanding network capacity. This also supports the need for the incentivisation of network operators to minimise network barriers to achieving net zero, a responsibility which should partly fall to the new system operator.

The model has not considered CCUS or carbon removal technologies for the islands, both of which were deemed unsuitable on grounds of technical and economic suitability. The effect of these technologies on results might not necessarily be confined to their deployment on the islands though. If any demand for the islands was considered as the final, hardest, and therefore most expensive percentile to decarbonise then it could make nature-based carbon removals suitable. If this was through a credit system though, the source of carbon removals would be unlikely to be the islands (given the economic issues discussed in Section 3.5). Given the lack of high temperature processes (which as discussed in the above section could well be electrified), it would be unlikely that decarbonising whisky would be more complex than steel or concrete. If the scale of removal technologies, nature based or anthropogenic, is such that is could enable the hardest to decarbonise sectors on the islands (distilling and the ferries) to continue to produce emissions, the role for local electrolysis would be greatly reduced given the higher costs to export hydrogen from the islands.

Comparing the renewable supply model with recorded data showed it tended to overpredict peak generation (Section 6.1.2). For the islands, this could have the effect of over-exaggerating curtailment and network stress. This would reduce the electricity that could be exported in all scenarios and likely reduce the energy that would be available for electrolysis. This effect would be more pronounced for the BAU and Export scenarios with the highest generation capacity - 2.4 GW compared to 1.3 GW in Independence. With less generation available, it would probably make the Middle Way and Independence scenarios more attractive due to the higher efficiency and would minimise dependency on imported energy. Although electrolysis load factors would be reduced, the estimated winter load factors would be less affected due to wind not being at peak capacity. With load factors of up to 39% in the winter, they are still significantly higher than the 25% estimated by BEIS modelling (BEIS, 2021a), likely meaning that the modelled price of hydrogen from the FES is overstated, which is discussed in the following Section.

For biogas, there are several assumptions that could have affect results. The literature highlighted instances where co-digestion was observed to increase the biogas yield of anaerobic waste digestion, but due to a lack of data or more detailed anaerobic digestion model, this was not accounted for. If the energy from biogas was improved through co-digestion, the results here could understate the potential biogas resource. However, given the dispersed nature of the islands and main finding that industrial demand would be best suited (in most cases except for the smaller islands – Section 5.6), a difference in biogas yield of say ±20% would be unlikely to change this result, at least relative to the other scenarios. It would however improve the case for policy to support cross-sectoral cooperation on waste utilisation.

Another issue is that of competing resource demand for biowaste. Care was taken to only select resources that either did not have competing demands, or that could be complementary (Section 5.5). If other demands were to affect resource availability, then depending on the waste stream, energy from biogas could be completely unviable for the islands. The existing literature for the bioresources of the islands highlights that this should not be the case, but if innovative non-energy uses were found that were more economic (and in the absence of policies to support distributed and more remote biogas production), this would clearly make the technology less viable.

7.5.4 Market and price assumptions

A major assumption in the model that could change in the coming years is the electricity market structure. The model was set up assuming uniform mainland and island electricity prices, but this could be altered under the Government's ongoing electricity market reform proposing LMP (BEIS, 2022i). Given island network constraints and excess generation, LMP would likely have a greater effect than many places in the UK. Given the planned (and in some areas such as Orkney, existing) renewable capacity exceeding local demand, the scale of curtailment could massively depress electricity prices and incentivise local demand - likely to be industrial or electrolysis (the latter subject to the issues discussed in Section 7.5.2). Households would in theory be less sensitive and/or exposed to these prices. This would have the effect of encouraging the Export scenario via reduced electricity costs if electrolysers would pay for curtailed energy (again discussed in the following section). If households and businesses were exposed to lower local prices, it could also disincentivise investment in efficiency, making a lower demand scenario less feasible, but likely encouraging flexibility measure such as DSR. If there is no business case for electrolysis on the islands at whatever price of electricity, then if the low electricity prices caused by the surplus of generation relative to local demand did not incentivise the growth of other demand, then it would make any further expansion of generation on the islands extremely unlikely given the high existing proportion of curtailment. This dramatic change to the UK's electricity market will clearly have a disproportionate effect relative to the rest of the country given its energy landscape. Whether or not it is implemented will only become clear in the coming years.

In modelling hydrogen production for the islands, due to time constraints it was assumed that electrolysis would operate whenever there was excess renewable generation on the system (e.g. that would otherwise be curtailed). This was done by setting the market and shortage price in PLEXOS as equal to offshore wind (Section 3.2.3), assumed to be the most expensive generation type used to produce hydrogen. The price of hydrogen produced for cost calculations was instead considered as the range specified in the FES (Section 3.3.1). The price paid for electricity could therefore constitute part of the price of hydrogen used in the model (for reference, the assumed price of offshore wind – £50/MWh – would make up 14-42% of the £120-350/MWh assumed hydrogen price) depending on the payment structures in place. This will be affected by what curtailment arrangements there are for generators, as it seems unlikely electricity producers will be unwilling to provide electricity for free to electrolysis versus receiving curtailment payments.

The price paid was not however considered in the optimisation process of PLEXOS, meaning that the operation electrolysis for the islands is based on assuming that either there is demand local or a wider hydrogen market willing to purchase it. It is likely that at the capacity factors modelled (a minimum of 31% in the low-wind winter scenario and up to 68% in the summer, compared with an average of 25% assumed in Government modelling) (BEIS, 2021a), the price of hydrogen produced could be much lower than assumed. Quantifying the this though would require further analysis to compare the techno-economic characteristics of electrolysis technologies in a similar manner to the calculations of bioenergy prices (Section 5.4). This could include comparing technologies such as alkaline, proton membrane exchange, and solid oxide electrolysis, along with the payment structures and availability of low-carbon electricity (whether available directly from the local grid or paired directly with a specific generator). This could be combined with economic modelling of transport costs, storage costs, and potentially conversion into other fuel types such as ammonia. This would give a better estimate of the potential price of hydrogen for the region based on these parameters, which is one of the key determinates how viable the technology might be for remote communities.

The main point of including electrolysis in the model has been to demonstrate how it can support local decarbonisation though minimising curtailment, hydrogen import costs and support a localised approach to net zero. For the islands specifically, in the case that hydrogen was available at an extremely low price (e.g. underground hydrogen reserves prove to be as abundant as natural gas), hydrogen for the islands would still be subject to transportation costs (or require conversion to alternative fuel types which would incur a loss in efficiency as discussed above). If these were also not reduced, then the case for island electrolysis would depend on the trade-off between the local production (as well as the valuation of local network benefits of the flexible demand). Further analysis of this hydrogen uncertainty could compare the required minimum price of imported hydrogen required to match the above local production scenarios compared with transportation costs (which could include a pipeline to the mainland being built) and how local benefits are considered. Being able to more quantitively compare the price of hydrogen produced locally would give greater confidence in how feasible electrolysis for the islands would be but would require further analysis.

Other prices assumed in the model are also subject to uncertainty bounds. For generation, the main issue could be if the merit order of dispatch were altered. For example, a case for this would be if the price of electricity produced by SMRs could be similar or cheaper than offshore or island wind, as some technology developers claim it will be (Matthew and Walker, 2022). Given the greater locational flexibility (assuming they would be allowed to be built near centres of demand), this would dramatically disadvantage island generation at the far edges of the UK electricity network. However given the development timescales and pace of development already underway (with most of the proposed interconnections under construction or operational now) or proposed (wind farms taking much less than a decade to build), the slower pace of emerging technologies such as nuclear (likely not until the end of the 2030's) would be unlikely to affect the development of the islands by 2030. It is almost certain that no new generation technologies will emerge to contribute to the Government's goal of decarbonising the grid by 2030, therefore as much capacity of current technologies like onshore wind will be needed in the shorter term. By the time new technologies are available though, they could have a role in reducing the value of renewable generation on the islands. Given the scale of generation in all the modelled scenarios, this would make them similarly unlikely to occur, given the low local demand relative to higher interconnection capacity. If there was no need for local generation, local demand could easily be met by imported electricity.

Costs for demand-side measure are also uncertain, being based on EPC data which has been highlighted in numerous ways in the literature (as well as here with respect to solar PV recommendations- Section 6.5.2). It was attempted to adjust the overall costs to proportions more representative of the wider UK (Figure 7-14) to better compare the scenarios, however the uncertainty bounds here are still very large given the uncertainty in the underlying prices and further extrapolation required. Comparisons of the overall cost of the different scenarios is therefore less robust. The main point of comparing costs between scenarios though was to analyse the different distributions of costs and benefits throughout the various stakeholders (consumers, producers, network operators, etc.). Regardless of the magnitude of the different costs, how there are distributed is more robust. The economic structures of how different aspects are paid for (e.g. households or tax-payers financing efficiency improvements; bill payers financing generation) is much less uncertain looking forward to 2045, as well as the fact that someone with a better insulated home will benefits from it more than an energy supplier. In this sense, a main finding that there is a fundamental difference in how equitable a demand-led versus a supply-led net zero transition would be is more robust to the assumptions. How serious this difference is though is dependent on the magnitude of the costs assumed. If the levels of efficiency improvements modelled here (which to reiterate does not assume any change in behaviour, only technologies used to meet demand) would be too costly, particularly for example building fabric improvements, then for the islands specifically, less electricity could be exported and more would be needed locally. As a representation of larger energy systems, the overall size of the energy system would need to be larger, with more spent by households and businesses on energy. Given emergent unrest the last few years where groups have been unfairly disadvantaged by decarbonisation policies, it surely makes sense from the perspective of achieving a just and democratic net zero transition to try to factor this into the design of the energy system through energy policies.

7.6 Sensitivity analysis

Having examined the sensitivity of results to major assumptions, this section will examine the sensitivity of results to three main variables:

1. The price of electricity paid for by electrolysis and the effect on the overall price of hydrogen.
2. The extent of planned network upgrades, both to the mainland and on the islands.
3. Flexibility in electricity supply, from a demand (DSR) and supply (curtailment) perspective.

7.6.1 Price of hydrogen and electricity for electricity

The price of hydrogen was not directly modelled using PLEXOS, therefore understanding its price requires separate modelling of the overall price of hydrogen. To do so the UK Governments hydrogen production cost data has been used (BEIS, 2021a), as the most comprehensive and recent Government publication concerning hydrogen cost estimates. Although not the most up-to-date, electrolysis capacity globally increased from 0.57 to 1.39 GW from 2021 to 2023 (IEA, 2025), which although large in percentage terms is minimal in absolute terms, therefore the findings of the 2021 report are unlikely to have changed significantly. The cost data used from this are given in Table 20 of Appendix B- the LCOE formula used is given in Equation 5.4 of Section 5.4.

Levelised cost of hydrogen (LCOH) was calculated for 2045 based on an average of two technologies (alkaline and solid oxide electrolysis, as per Section 3.6.2) and compared with the estimates from the BEIS report (Figure 7-15). For each island scenario, the LCOH was estimated for a case where the electrolysis does not pay for electricity (left side of the figure) and another where it would pay the LCOE of generation on the islands (right side of the figure). For both cases, two options of transport costs have also been applied, for a pipeline (£6/MWh) and compressed hydrogen trailer of 1,3000 kg (£44/MWh) (DESNZ, 2023h). Note that the prices shown for both in green are the final prices (e.g. the trailer cost does not stack on top of the pipeline costs as for the CAPEX, OPEX and electricity costs). This allows for the economics of use cases for hydrogen to be assessed.

These prices were compared with the prices from the BEIS report in three cases (shown as lines on the figure): one assuming no price paid for electricity and a 25% capacity factor (based on average curtailment from modelling of 2050 electricity system); another assuming a direct connection with an offshore wind farm, paying the LCOE for the generation; and assuming baseload operation with electricity at the market price of electricity (BEIS, 2020c). The third case has not been calculated for the islands as given the same input parameters (a 95% capacity factor), the price would be the same. Note that the lowest cost shown (for no electricity costs paid) is comparable with the cheapest blue hydrogen production method in the same report (auto-thermal reformer and gas-heated reformer with CCUS at £55/MWh).

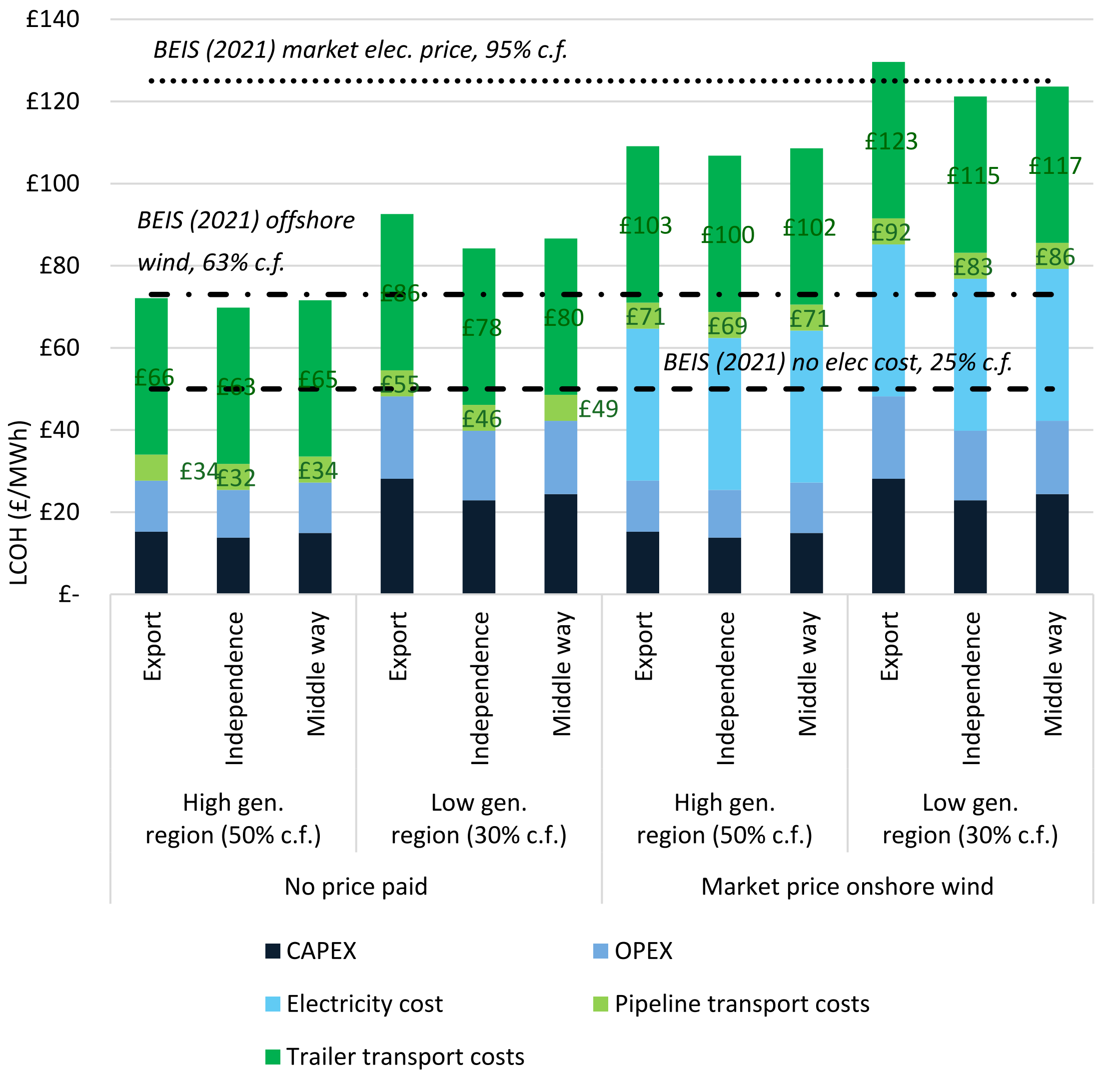

Figure 7-15: Modelled hydrogen prices in 2045 based on varied capacity factors (c.f.) and electricity prices for an average of alkaline and solid oxide electrolysis electrolysers. BEIS estimates are shown as lines(BEIS, 2020c). *Note that the prices shown for transport* (DESNZ, 2023h) *in green are the final prices (e.g. the trailer cost does not stack on top of the pipeline costs as for the CAPEX, OPEX and electricity costs). High generation regions refer to Orkney, Shetland, Na h-Eileanan Siar, and Highlands; low generation regions refer to Argyll and Bute, and North Ayrshire.*

Firstly, to consider cases excluding transport costs (blue bars only). Whether the electrolysis pays for electricity or not, the price of hydrogen is cheaper or in the case of the low generation regions, roughly comparable with the dedicated offshore wind BEIS price. Where electricity is not paid for (the left side of the figure), the high capacity factors resulting from a greater proportion of curtailment (30% in generation with low generation capacity, 50% in regions with higher capacity) than assumed in the BEIS modelling of 25% (BEIS, 2020c) correspond with a proportional reduction in the LCOH. In the case where electricity is paid for though, only for the higher generation regions is the price more competitive than the BEIS modelling. It seems that the small decrease in electricity price paid (onshore instead of offshore wind) is enough to offset the slightly lower capacity factor (50% for the islands, modelled as 63% for offshore wind in 2045). The larger difference for low generation regions is not enough though, resulting in a higher price for the case on the far right of the figure. This would indicate that if electrolysis is co-located with demand (e.g. transport costs are excluded), that island hydrogen would be cost competitive with imported green hydrogen sources, even if excluding the transport costs needed to bring them to the islands.

If compared with the cheapest source of blue hydrogen from the same report (auto-thermal reformer and gas-heated reformer with CCUS at £55/MWh), the islands would be competitive if they did not pay for electricity or else in the high generation scenario once transport costs were factored in for the imported blue hydrogen (£6/MWh for pipeline and £44/MWh for trailer). This again makes the case for co-location of production and demand- provided there is significant enough local curtailment. If hydrogen can be produced more cheaply in-situ than produced elsewhere, but transport costs remain significant, then the best case for hydrogen demand and supply on the islands would be to produce it locally.

The case for local production is especially so for the islands, as with relatively low local demand and non-existent natural gas infrastructure save for the Flotta terminal on Shetland, that the only transport option would likely be by much more expensive trailer. For this mode, transport costs make up an average 41% of total costs in the electricity price paid case, and 62% in the no electricity price paid case. Likely the only way that imported hydrogen would be cheaper than local production would be if the price of natural gas falls to near zero. Given the average LCOH for the high generation, onshore wind electricity price case is £64/MWh, the BEIS LCOH of £99/MWh would only be comparable if the gas component of £35/MWh was reduced to zero. Therefore, for remote regions without an existing gas network (irrespective of the uncertainty around whether or not natural gas infrastructure can be readily adapted to hydrogen) and unlikely to be worth construction of a new pipeline due to limited demand, for sectors that hydrogen is to feature in decarbonisation plans, it seems likely that the only cost-effective method would be for hydrogen to be produced and used locally. This would also indicate that where existing infrastructure and technologies are available (e.g. electrification of low-temperature industrial heat), the price and complexity of local hydrogen production would be much less attractive.

Regarding the differences between scenarios- in all four generation and price configurations, the Independence scenario has the lowest LCOH, but the extent of this effect varies. In areas with high generation capacity, the effect is more limited, with a 3.5% and 8.3% reduction in the price for the onshore wind price and no price for electricity cases respectively. While this difference is significant, it is unlikely to offset transportation costs. This would indicate that given the scale of onshore wind modelled for the islands (1.3-2.5 GW; see Section 6.5) relative to local demand (peak demand of 120-200 MW), the order of magnitude difference in the demand and generation capacity means that the relatively small improvements to demand efficiency have less of an effect on the capacity factors of local electrolysis capacity. For low generation regions though, the difference between scenarios is more notable at 9.8% to 17.4% by electricity price scenario. For these regions with low to no generation capacity, electrolysis will mostly operate using imported electricity from renewables. That the difference in prices is more significant here indicates that for the Independence scenario, the lower demand seems to effectively unlock additional interconnection capacity compared with the Export scenario, allowing the electrolysis to operate more frequently and so bring down the LCOH. This again highlights the complex role of electrolysis demand on electricity networks and how more work is needed to understand their effects on electricity systems.

7.6.2 Extent of network upgrades

To understand the effect of additional network capacity on results, the expected network upgrades modelled have been varied. This only includes network capacity where the model indicated network expansion would be needed (as shown in Figure 6-13), either to facilitate additional generation capacity or to meet growing demand. The capacity (MW) of these network interconnections, both within the islands and connecting to the mainland, were varied by +/-50% as shown in Figure 7-16. To make the most equivalent comparison, this was done for the BAU (without electrolysis) and Export (with electrolysis) scenarios, for which all other technology capacities (see Figure 3.7) are equal.

In the Export scenario (left side of Figure 7-16), electrolysis capacity rather than network interconnections is the main way the scenario addresses island curtailment. Hence, curtailment is minimally affected in absolute terms. For the range of network capacity -50% to -20%, curtailment is barely reduced at all, while the electricity exported from the islands increases. For this configuration, additional network capacity increases the amount of exported electricity at a similar rate to the BAU scenario (without electrolysis). This has the corresponding effect of reducing the electrolysis capacity factor slightly, as rather than being theoretically curtailed (what would be the case if there was insufficient network capacity to export the electricity) and instead used to produce hydrogen (see Section 3.2.2 for details on how electrolysis dispatch is optimised), the electricity is exported to the mainland.

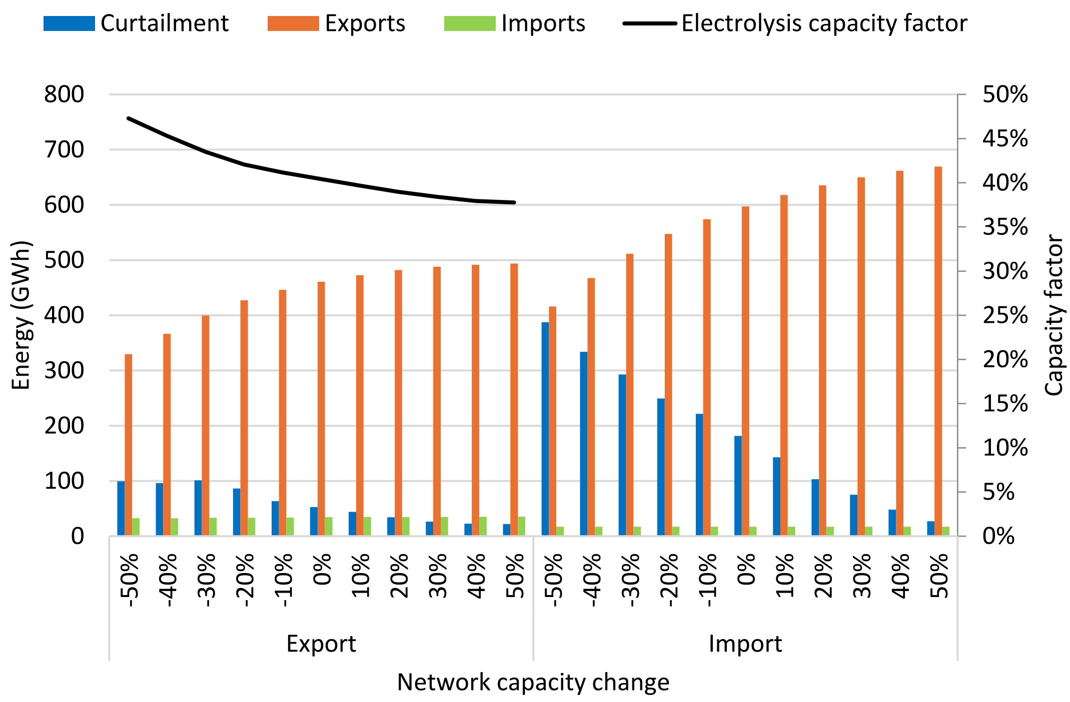

Figure 7-16: Sensitivity analysis of network capacity (+/-50%) for key metrics.

Beyond this though in the Export scenario, in the range of -20% to +50% network capacity, the effect on exported electricity is minimal, with curtailment decreasing from 9% to 3% of the total generation. The utilisation of the modelled generation capacity would appear to be maximised, whether through electrolysis or being exported to the mainland. Given the extent of network costs in the base case (Figure 7-12), it seems unlikely that additional network expansion would be economical without additional generation to boost the electricity produced, exported and/or used to hydrogen production.

Throughout the varied range of network capacity in the Export scenario, the imported electricity varies the least, by -5/+3%. As the electrolysis capacity factor also decreases proportionally to the additional electricity exported, the electrolysis capacity on the islands (the only source of demand that varies between the two halves of the graph) is clearly dependent on local generation. The increasing availability of network capacity to import electricity to the islands has a minimal impact on electrolysis production. This again reinforces the point that electrolysis will be most efficient if co-located with generation. If the additional network capacity here has a minimal effect on the load factors, then it would make it an ineffective way of attempting to improve hydrogen production.

In the Import scenario (right side of Figure 7-16), given the lack of electrolysis to utilised local curtailed electricity, the effect of additional network capacity is clearer. The additional network capacity directly increases the electricity that can be exported as it is the only way otherwise curtailed local electricity could be utilised. The relationship between greater interconnections and the amount of curtailed/exported electricity is not exactly linear however. Similarly to the Export scenario, there a slight inflection point at about -20% network capacity, where the rate of increased electricity export per unit increase in network capacity lessens. This could be due to high generation periods coinciding with the mainland, as curtailed generation in the mainland node would preclude island generation being exported. The marginal value of additional network capacity decrease beyond this point, which combined with the high upfront cost of additional network capacity would indicate that for the modelled generation capacity, local use of the otherwise curtailed generation would be a more cost effective option.

Obviously though this would depend on how generators are compensated for curtailment, as discussed in Section 7.5.3. This would also be heavily influenced by the extent of network constraints in Northern Scotland, as these could require that the generation modelled here as exported was actually curtailed. The newly constructed Viking wind farm, the largest wind farm on the Scottish islands, has been forced to curtail output around five-sixths of the time since it began operation (Shetland News, 2025). This combined with the expected growth in onshore and offshore wind in Northern Scotland and without an equal expansion of network capacity (SSEN, 2023a), would indicate that the curtailment experienced by the Viking wind farm foreshadow the fate of other large renewable generation on the islands. Incentivising local utilisation of the electricity produced would require reform to electricity markets, which are discussed in more detail in Section 7.5.4.

7.6.3 Demand side flexibility

Demand side flexibility was similarly varied by +/-50% to isolate the effect it had on the system for the Independence scenario. The variation for curtailment and line utilisation is shown in Figure 7-17. This base case assumes that 50% of electric vehicle charging, heating, and hot water demand could be flexible, so this analysis shows participation of these end users in demand response programmes varying from 25-75%. In the Independence scenario, this corresponds to 16-50% of peak demand (see Section 4.7.5 for demand response potential). While other technology types could be suitable for participation in flexibility programmes (particularly industry and commercial end-users), this range of peak demand reduction is already in excess of the most highest demand response case in the Future Energy Scenarios (39% of peak demand for the Consumer Transformation scenario) (National Grid, 2023). This is due to the higher proportion of domestic demand on the islands (roughly half- see Figure 4.15). Given the similar proportions of peak demand, the range from this set of technologies will be suitable for this sensitivity analysis.

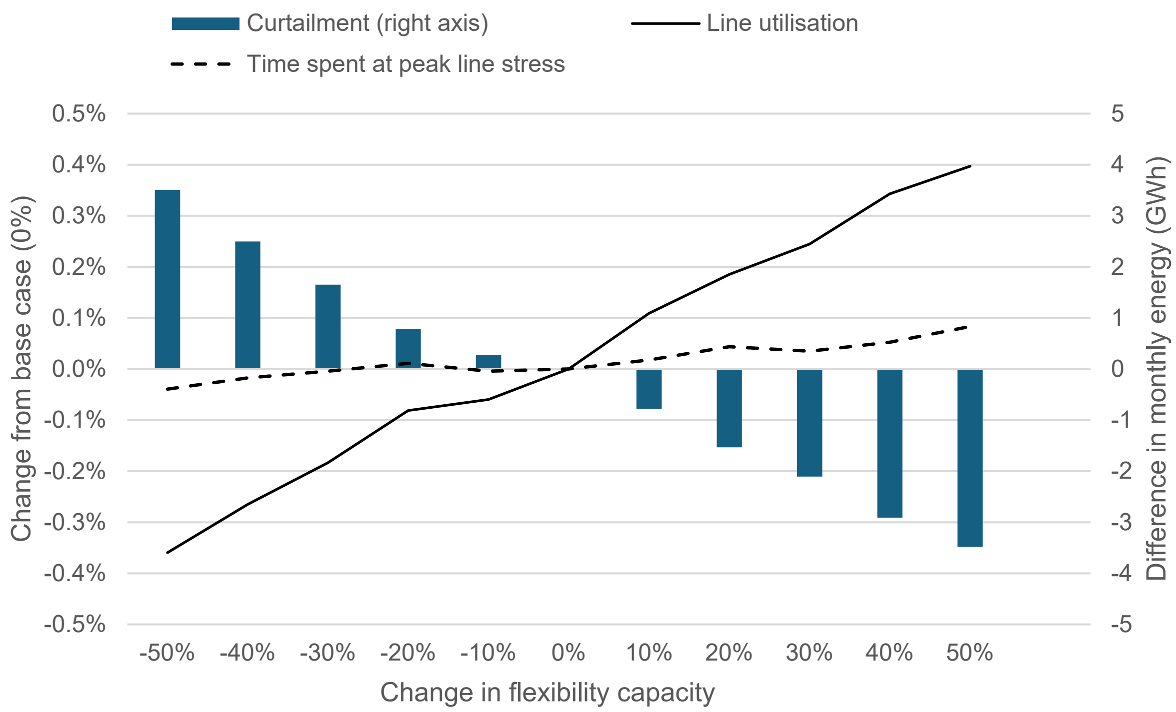

Figure 7-17: Sensitivity analysis of flexibility capacity (+/-50%) for key metrics.

The effect is clear of greater demand response capacity directly reducing curtailment, by enabling demand to be shifted to periods with excess renewable generation. It should be reiterated that the scale of generation on the islands (1.3 GW for the Independence scenario modelled here) outweighs the local demand (maximum flexibility of about 40 MW), so the relative scale of the difference in curtailment is minor at around +/-1%. Given the scale of demand relative to generation capacity, there is a clear linear relationship (e.g. the slope of the change in curtailment is constant), indicating that if there are limits to how much flexibility can reduce curtailment, they are not approached by the scale of potential demand response in the islands. In regions with greater demand relative to generation, the marginal value of additional flexibility might differ. For the islands though, or other regions limited by network capacity in the extent of low-carbon electricity they can import, flexibility of demand (once suitable demand such as heating or passenger vehicles have been electrified) has a clear role in minimising curtailment.

Similarly, given the scale of island generation and networks (for this scenario additional network capacity of 2.1 GW compared with 40 MW peak flexibility), the effect of flexibility network utilisation is linear for the varied range of flexibility. The additional potential of flexibility to increase demand during periods of excess renewable generation on adjacent island nodes of the model allows the electricity to be exported locally within the island group, which increases the utilisation of the network as shown. The scale of flexibility relative to the network capacity makes this effect minimal from -0.3% to +0.4%, but the increase demonstrates how demand flexibility can maximise the utilisation of renewable generation without the need for additional network capacity, maximising the usefulness of existing infrastructure.

The time spent at peak network stress (classified as >95% line utilisation) is also increased, but to a much lesser extent, which would indicate that although line utilisation can be increased through exporting excess generation to adjacent nodes, the extent of this at peak times can also be offset by flexibility in the same node in the model. Although time spent at peak network stress is not inherently an issue, it indicates a stress point in the model where an increase in the network capacity could provide a more optimal solution. If this is minimally affected, then it demonstrates that local flexibility can provide similar benefits to network capacity, but this effect can only be shown here for the case of much higher generation capacity relative to demand. In regions where the scales of technology capacities are more comparable, the relationship will likely be less linear.

7.7 Discussion of Net Zero model results

The overall energy balances of the scenarios demonstrate the feasibility of net zero within the technological constraints applied to the model as detailed in Chapters 3-6. In setting up scenarios, it was not intended that they be optimised, as this would depend heavily on assessment criteria and the perspective from which "best" is framed from. Rather, they present alternative perspectives on how net zero could be achieved for the islands and examined for the implications for getting there within the next two decades.

BAU and Export scenarios have the highest generation capacities, but even with additional network capacity, curtailment is highest in BAU, both absolute and as a proportion of the total generation. The sensitivity analysis of Section 3.6.2 show this could be reduced with greater network capacity, but as shown in Section 7.4.1, this likely be more expensive than developing local demand or flexibility. Whilst some curtailment is not necessarily incompatible with an efficient energy system, the 44% summer curtailment in the BAU scenario could surely be better utilised to produce a storable energy form - provided there was a demand for it. It means that despite electrolysis inefficiencies, the total energy exported in Export scenario is comparable with the BAU. Indeed, with hydrogen being more expensive than electricity, the total value of exports would be much higher with electrolysis. However, the proportion of energy which can be exported to the mainland is greater for the Independence and Middle Way scenarios - despite having lower generation capacity - through commitment to efficiency policies. Whether reliance on imported electricity and/or hydrogen is preferable will depend on factors external to the model such as the market for hydrogen, how feasible importing it is (Section 7.5.1), the perceived value of the additional security for the system, and from whose perspective the question is considered (Section 7.5.3).

Even with additional investment in network upgrades for generation, reduced investment in efficiency and flexibility for the BAU and Export scenarios results in consistent unserved energy for several nodes due demand electrification exceeding existing island interconnections capacity. This could however also be due to error in the equation used to predict network capacity (Section 6.1.3) which was used due to the line capacity data not being available from the DNO. In any case, investing in measures to reduce demand would minimise requirements for expensive network upgrades.

Scenarios have been set up with the differences in security that can be assessed qualitatively. The reduction in demand; addition of DSR, V2G, distributed storage and generation; and electrolysis capacity for local demand, makes the Independence scenario the most resilient. Distinction should be made between technologies contributing to local security that could benefit from economies of scale. Demand efficiency or flexibility through DSR and V2G are unlikely to be significantly cheaper elsewhere in the UK, which would make investing in them low-regret options as demonstrated by the sensitivity analysis of Section 3.6.3. Others though, such as distributed storage, distributed generation, and electrolysis are likely to be more expensive than other larger-scale alternatives, which could raise doubts about their suitability for deployment in remote communities. The benefits that they could have for local energy networks would need to be better understood and potential evaluated with additional costs - for example the relatively low resolution of the nodal model here could over-look local grid constraints that could be a limiting factor.

Resilience of scenarios can also be assessed through network stress. Even factoring in reduced electricity and hydrogen demand, electricity demand for electrolysis is significant at 99-134% in the winter low-wind scenario and 244-410% of local electricity demand (excluding electrolysis) in the high-wind summer. For the three scenarios with island electrolysis, this increases time spent at peak stress for nodal transmission lines, particularly for the Export scenario which imports more electricity to run electrolysers. Reducing demand in the more efficient scenarios leaves more capacity on the network for generation expansion and resilience in the event of an outage. Results show that balancing a net zero electricity network is much more complicated, particularly if electrolysis for green hydrogen is to take off as a way of utilising excess renewable generation. For the islands, demand flexibility has a clear role in reducing curtailment without adversely affecting network stress and so should be maximised. For more self-contained regions (e.g. where the balance of demand and generation is more equal), the marginal value of demand flexibility will however be different, and it is possible that the heavily network constrained nature of the islands exaggerates the value of local flexibility. Optimally incorporating new technologies which could create difficulties with existing regulation constrained network operators will be a crucial adaptation required to realise net zero. Digitalisation and communicability are crucial for removing the barriers faced by new technologies being approved to interact with electricity markets. With the expansion of Ofgem’s remit to include net zero targets in the 2023 Energy Act (UK Parliament, 2023), they will be responsible for regulation, but how this will be filter down to network operators is not yet clear.

7.7.1 The role of hydrogen and electrolysis

The largest uncertainty in the final model is the role of hydrogen. Whilst, hydrogen has been locked in hype-cycles since energy crises in the 1970’s (IPCC, 2022), it seems increasingly likely that it will be needed to decarbonise some categories of demand - specifically heavy land-based transport, industrial heat, and marine transport (IEA, 2022b). The extent and scope of this though, such as the efficiencies in final demand, need for electrolysis, local storage, imports of fuel, and more could vary widely. Examining the assumptions used for hydrogen and electrolysis likely raises more questions, but this can be used to analyse what the key policy and market structure decisions might be.

The results showed that localised electrolysis (Export scenario) can reduce curtailment by 30% in the summer high-wind scenario relative to increased interconnection capacity (BAU scenario). As the islands could export hydrogen at a higher value than electricity, this compensates for the loss in electricity exports and could result in a more positive net financial outcome for the islands taken as a whole. This is however highly dependent on the assumption from BEIS modelling of hydrogen costs (BEIS, 2021a) that electricity for electrolysis (otherwise curtailed) would be available at zero cost to electrolysers. The BEIS report found this to be the cheapest way of producing hydrogen using electricity, but assumed a load factor of 25%, whereas the modelled results showed regions with higher generation capacity had load factors 65-69% in the summer and 28-39% in the worst-case lows-wind winter month. This could massively reduce the price of hydrogen (discussed in Section 8.1).

In 2022, curtailment payments averaged £202/MWh including generator compensation and energy from back-up generation (de Berker, 2024). If electrolysis capacity is co-located with generation and demand (discussed below), existing renumeration for curtailment is surely in direct conflict with the assumptions of the BEIS report. The alternative form it could take though is not clear. Whilst it is possible that greater curtailment could be the least-cost net zero solution, it would require that the cost of replacement generation is not as expensive as the generally gas generation which currently makes up the greatest proportion of curtailment costs.

The Government approach is to support both green and blue hydrogen projects through a 10 GW target for 2030 to by met by CfD allocation in either. It has also stated commitment to hydrogen projects that could enhance network resilience (discussed in more detail in Section 8.1) (DESNZ, 2023g). Without a national transport network are developed, nascent hydrogen production will need to develop in areas co-located with demand (National Grid, 2023). Hydrogen storage costs were modelled without a margin of safety, making them a lower bound. Despite this, hydrogen storage or imports were the greatest single OPEX cost category for both Export and BAU scenarios. This would be highly dependent on the price of imported fuel, if transporting it to the islands is economically feasible, and costs of the modelled liquefied storage.

The high costs of transporting hydrogen and storing (excluding by pipeline) (DESNZ, 2023h) could make local hydrogen production the only economically viable option for the islands or other isolated communities. However, comparison of high and low generation regions showed that without sufficient local generation, electrolysis would be much less efficient and therefore expensive. Better understanding of how electrolysis can be integrated on electricity networks is needed if it is to play a role in hydrogen production.

Results are particularly dependent on assumptions for hydrogen transport and storage. These have not yet been demonstrated at scale, making the optimal technology format more uncertain. Only liquefied hydrogen storage was modelled due to the closest cycling frequencies in hydrogen cost modelling (DNV GL, 2019) to existing fuel delivery periods. The costs for pipeline and trailer transport were modelled in Section 7.6.1. These calculations demonstrate that the cost of hydrogen would be prohibitive without a cheaper pipeline, indicating that the only way hydrogen would be feasible for remote communities is if production is co-located with demand.

It is particularly unclear how hydrogen storage for the islands could operate given the remoteness of the islands and yet-unresolved difficulties in transporting hydrogen, which could necessitate other energy vectors such as ammonia. With the lack of a gas distribution network on the islands, the same problems have evidently been experienced in transporting natural gas, resulting in the dependence on electricity and other more transportable solid or liquid fossil fuels. Distribution of the fuel within the nodes in PLEXOS is also not modelled. What form this would take is unclear - whether there is a local distribution network between industrial users or demand must be relocated to be closer to import areas.

If hydrogen is to be green rather than blue, inefficiencies in conversion to ammonia for transportation will make it more expensive than the basic hydrogen needed as a feedstock, making non-electrical fuels for the islands much more expensive than the mainland. The Government's hydrogen transport strategy consultation mainly focuses on large-scale, pipelined distribution (DESNZ, 2023h), making it inapplicable for remote areas lacking an existing gas network. As producing ammonia from hydrogen using the Haber-Bosch process is currently 50-70% efficient and energy costs are one of the main overall cost factors (BEIS, 2021a), it would make ammonia significantly more expensive than pure hydrogen. If this is the case, then combined with the benefits of reducing curtailment and reduced network upgrade costs would likely make scenarios with local electrolysis more attractive (assuming that the investment decisions can be made by those realising these benefits). That water requirements could be only 3-12% of current demand by local authority in the Export scenario demonstrates that water stress should not be a major issue. If imported fuels are significantly more expensive, then making sure that the islands and other similarly remote communities are not left behind in the transition to net zero may require policies targeted to support them.

Market structures will need to allocate excess electricity to electrolysers and determine its price, which will surely be greater than zero, despite Government hydrogen costing. Modelling of the hydrogen price in Section 7.6.1 shows that even if local electrolysis were to pay the market rate for onshore wind on the islands, in the regions with higher generation capacity, it could be cheaper than BEIS modelling for dedicated offshore wind if used locally. This would require management of electrolysis demand so it does not cause unserved demand and determine limits for regional electrolysis given available generation and capacity constraints. Ofgem could be responsible for this at a national level, but at a local level, DNOs will need to be involved as well to ensure additional stress on the network is managed. The 22% higher load factors of electrolysis co-located with greater generation capacity demonstrates that electrolysers should be co-located not just with demand, but also generation capacity. Further work will be needed to quantify the potential synergies between demand efficiency and electrolysis.

Electrolysis has been configured in PLEXOS to only run on excess renewable generation. This resulted in ramping that could be considerable for island electrolysis. As the scale of excess island generation was generally greater than the electrolysis capacity, this resulted in electrolysers frequently ramping from 0-100% hour-to-hour. This resulted in the ramp rate varying from 12-38% on average, being slightly higher in areas with more generation. But while this well within values in the literature (BEIS, 2021a), concerns about minimum operating levels and other factors have not yet been fully addressed to demonstrate the compatibility of intermittent renewables and electrolysers (Hydrogen Insight, 2024b). With different electrolyser technologies having different performance characteristics, this could be a key factor in deciding which is more suitable for wider energy system integration, particularly if they are to provide secondary balancing services through reducing curtailment. This will have synergies with other aspects, discussed in Section 8.1.

7.7.2 How can biogas contribute to net zero?

With the outputs of the biowaste model (Chapter 5) integrated with the Net Zero model, how it could fit in the overall energy balances of the islands is considered in the Independence and Middle Way scenarios. The relative potential of biogas in these scenarios is related to demand efficiency differences. In the Middle Way scenario, the biogas potential varies from 2-4% of the total electricity and hydrogen demand (excluding for electrolysis), whereas for Independence it could provide 10%. Whilst not large in absolute terms, this combined with efficiency improvements could reduce dependency on imports or local electrolysis capacity and improve the resilience of these scenarios. Particularly considering uncertainty in imported hydrogen prices, building up local biogas production capacity would minimise the exposure to volatility in prices (again dependent on hydrogen markets) and provide local low-cost energy for certain industrial activities which could be co-located. The adaptability in terms of scale and relatively low running cost could make biogas an interesting part of the net zero energy mix.

The overall results mask regional differences though. While there is biogas potential for all the local authorities due to the availability of both domestic and commercial food waste, industrial waste is more concentrated (Figure 7-11). As biogas boilers were identified as the most suitable use of the fuel (Section 5.6), this highlights the synergies between industrial waste and heat demand. For the islands, the most obvious candidate is the distilleries. Whilst it could still provide energy in other cases (such as through CHP), it seems more likely that an industrial case would be the best solution. Combined with efficiency improvements, biogas from industrial biowaste but also non-industrial (which would increase the available energy and could reduce the cost of energy - Section 5.6), could allow four out of the six local authorities meet nearly all their industrial heat demand. For Argyll and Bute, with the highest concentration of distilleries but a lower population, the proportion is about half which could offset demand for hydrogen. If the equivalent cost for a hydrogen boiler was used as the threshold energy cost (likely to be more expensive than the fuel oil assumed), it could make more biogas potential economically viable, making more energy available.

7.7.3 Distribution of costs and benefits

Results show that the cost of transitioning to net zero by 2045 are significant, with total investment in the billions - provided net zero is achieved on time. Additionally, only those costs which vary between scenarios have been are modelled. Whilst the overall costs may be excessive compared with the islands' population of 100,000, a large proportion of costs for all scenarios is for generation more than local demand. This outcome could be instructive for the scale of generation anticipated for the rest of the UK, with up to 214 GW of renewable capacity modelled in the FES (National Grid, 2023). Costs for hydrogen are also significant, particularly for transport and storage (depending on the conditions discussed in the previous section). Results indicate though that the scale of investment for generation and hydrogen production/storage might be reduced through alternative investment in demand-side measures. The benefits of investing in greater efficiency for the Independence scenario is demonstrated by the huge uncertainty in the network costs in the BAU scenario, which could make it more than double the cost of the other scenario.

Looking at operational costs (Figure 7-13 - again, bearing in mind that the costs/incomes might not be contained within the islands), the Independence scenario has the best outcome for the islands. Only the two scenarios with greater efficiency investment but also distributed generation (Independence and Middle Way), have net positive outcomes balances. With demand costs scaled to be more representative of the mainland UK (Figure 7-14), the Independence scenario is still the cheapest except at the upper range of the scaling (but always cheapest for operational costs). For the other two, although there is greater income from exported energy, it is offset by households and businesses having much higher electricity bills (Figure 4-25). However, this outcome is highly dependent on electricity and hydrogen price uncertainty - with greater risk to potential upside and downside fuel price uncertainty. The more flexible and resilient Independence and Middle Way scenarios clearly could reduce the range of uncertainty in annual costs. The value added through converting excess electricity into hydrogen is also clear for the Export scenario, with a greater net average outcome than the BAU scenario.

Although the annual costs in Figure 7-13 are spread across the three categories of consumer, network operator, and suppliers, they will all eventually come back to households. This can be considered alongside the potential benefits. In the case of paying for efficiency measures, they could be borne directly by households (e.g. purchasing rooftop solar PV), supported through policy (Boiler Upgrade Scheme grant), or through suppliers (Energy Company Obligation obliging suppliers to target households for efficiency measures and funded by regulated bill charges). Whilst there are also systems benefits to reducing demand (Section 4.8), most of the benefits go to the household receiving the measure - a warmer home, lower bills, improved health outcomes, etc. Conversely, when electricity access is taken for granted, variation in generation and supply side investment between the scenarios would have much less upside for households as voters. Unless regional electricity prices are introduced (through LMP, local Energy Communities, or otherwise), households do not directly benefit from nearby generation infrastructure. Developers and suppliers receive the benefits and return on investment, which can be at a guaranteed rate via support mechanisms. Granted, renewable developers are increasingly required to invest back into communities (DESNZ, 2023i), but arguably these benefits are less direct than say, having a warmer, cheaper to heat house. Given the widespread objection to onshore windfarms and transmission network upgrades (Thomas, 2023), the downside is perhaps greater for local communities nearby to energy infrastructure, who along with everyone else pay indirectly for it through energy bills. To reiterate, the FES anticipates around a sevenfold increase in total wind capacity (not including network and other infrastructure upgrades) by 2050 (National Grid, 2023). Without mitigating measures, the scale and distribution of pushback against infrastructure could increase as well, which could jeopardise net zero entirely.

8 Conclusions and policy recommendations

Through in-depth modelling of the generation, demand, flexibility, networks, electrolysis, and biowaste of the islands, interactions and trade-offs between these energy systems aspects have been analysed. Four scenarios were modelled to examine distinct approaches to utilising the exceptional renewable energy resource of the islands. BAU combined higher generation capacity with upgraded networks to export electricity and meet the less efficient local demand. Export used the excess renewable energy capacity to power electrolysis, producing hydrogen for local demand and export. Independence combines greater investment in efficiency and flexibility with electrolysis for local demand. The Middle Way scenario presents a mid-point between the Export and Independence to consider a balance of costs between them.

These scenarios are intentionally not ranked through specific metrics. The point of their comparison is to demonstrate alternative pathways that could each achieve net zero - per the scenarios of the FES that they are loosely based on. In meeting the UK emissions reductions goals, each would be successful (a perspective including global supply chains could be different however). The main point of this scenarios modelling is not to say which is better or worse, but to understand the dynamics of interlinked energy sectors, scope for circularity to be included in energy systems, and how costs and benefits could be distributed between stakeholders. Understanding these broader factors affecting decarbonisation outcomes can improve how technology pathways are considered, particularly in the context of maximising the success of climate targets.

Before summarising the overall results and concluding with policy recommendations, key similarities and distinctions should be made between the islands and the rest of the UK. The computationally and data intensive nature of this thesis necessitates a relatively small geographic area, which was chosen as the Scottish islands. The islands have a very constrained local network, mostly electrified heating demand, and (some) have a high concentration of renewable capacity. Whilst this differs from much of the UK currently, it could reflect some of the potential challenges faced by 2050: wind capacity could increase by seven times; peak electricity demand could double; all whilst using network infrastructure which by 2050 could have been planned out a hundred years previously (National Grid, 2023). It is these conditions, resulting in high curtailment and energy prices, which have made islands like Orkney a test centre for innovative solutions, such as electrolysis, P2P energy markets, and marine energy, which could be needed across the UK to achieve net zero.

On the other hand, the islands are in some ways very different to the UK, which could distort analysis of results when making wider policy recommendations. As much as possible, these have been considered in the extrapolation of results:

- They are sparsely populated, with low local demand relative to a large generation potential. This exaggerates curtailment, as matching supply with demand is constrained by network capacity. However, this problem is already mirrored between England and Scotland, with greater wind capacity in the north and demand in the south. With potential wind capacity of 140% of peak demand (National Grid, 2023), optimising curtailed energy utilisation will surely be crucial. Mainland curtailment is unlikely to be at the same scale though and this could exaggerate the importance of solutions to this issue.
- Although some islands are interconnected, they all rely on mainland UK interconnection. European interconnections will play an important role in net zero through reducing energy prices (Pean, Pirouti and Qadrdan, 2016), but in terms of utilising energy produced, the balance of supply and demand in the UK will be more self-sufficient (i.e. most of the energy produced in the UK will be used in the UK). The reliance of the islands on interconnections with the mainland UK could over-exaggerate the prominence of network upgrade costs. More work is needed to understand how technology options compare in terms of utilising the excess energy.
- The islands lack a natural gas distribution network. If this was included hydrogen transportation costs could in some cases be much lower (with pipeline being one of the cheapest technologies) (BEIS, 2021a). This might have the effect of over-exaggerating the value of distributed electrolysis capacity as the greater costs for smaller capacity would be less offset by the reduced transport costs which could be available on the mainland. It is however not yet clear how suitable existing natural gas infrastructure could be for hydrogen (Rosenow, 2022), so the impact of this aspect is unclear.
- The remoteness of the islands makes transporting goods and energy more expensive, which is factored into the model (Section 3.6). Particularly for hydrogen, this could make distributed solutions more economical, as transport and storage costs could exceed the losses at smaller scales. This combined with a potential exaggeration of network constraints relative to the mainland UK would make the importance of distributed solutions greater for the islands or similar remote communities.

With this in mind, results can be summarised as follows. Demand-side measures are low-regret options. Specifically for the islands, they can minimise network stress and subsequent upgrades, reduce curtailment and increase energy for export. More widely and irrespective of any modelled differences between the island and mainland UK, they have the scope to reduce household and business energy bills both directly and through reducing system costs, improve health and wellbeing outcomes, and generally improve the overall resilience of energy systems. Flexibility has a clear role in reducing curtailment and avoiding expensive network upgrades, although these sensitivity analysis results are specific to the islands due to the scale of generation relative to demand- in other regions the effect could be less linear. Differences between scenarios indicates that efficiency might improve the load factors of electrolysis (a major cost determinant), but further work would be needed to confirm this. Similarly, improved utilisation of bioresources could add valuable diversity to energy systems whilst making better use of waste. Energy from waste could be feasible for the islands at costs competitive with existing energy types and likely much cheaper than potential hydrogen alternatives. Particularly in some cases, the potential for mixed waste streams is highlighted by reducing collection and overall costs. Support is needed to foster the collaboration between numerous stakeholders.

Other aspects are highlighted as more dependent on wider system configurations. Without greater commitment to efficiency or flexibility, likely more expensive network upgrades would be needed for the islands. Although network upgrades were shown in the sensitivity analysis to reduce curtailment to the mainland, this comes at a much greater cost than similar outcomes via demand flexibility or electrolysis. Results however highlight the great range of network costs, which can only be estimated between a wide lower and upper bound. Whilst greater network capacity would facilitate more electricity exports from the islands, without other measures, the proportion of electricity curtailed would also increase significantly.

Electrolysis is shown to reduce island curtailment, but this comes at the cost of much higher network stress which would require balancing. Co-location of hydrogen production, both with demand but also generation, has many synergies in this respect for managing the network stress and minimising costs, which were shown in the sensitivity analysis to be prohibitive for the islands or other remote communities without pipeline transportation. Particularly for the remote islands, hydrogen transport and storage costs could be prohibitive, reinforcing the importance of alternatives such as biogas for industrial heat. Given the greater uncertainty and immaturity of the sector, results pertaining to hydrogen are more dependent on model assumptions, the implications of which are discussed.

Significant large scale generation capacity will be crucial to net zero, but the exact extent could be affected in several ways. Demand measures and distributed generation could reduce the overall size of the energy system. This should minimise the overall cost, but also the physical disruption of large infrastructure and potential opposition to it. Results from all aspects of the modelling work highlight the uneven distribution of costs and outcomes, whether for households, businesses, or communities such as the islands. To maximise support for net zero, policies affecting energy sectors should be designed with this in mind. The differing overall balances of cost and benefits between modelled scenarios demonstrates how the burden of costs for the net zero transition can be differently structured, which could have implications for its ultimate success.

8.1 Low-regret aspects

In comparing the results of the Net Zero model (Chapter 7) alongside the specific sub-models (Chapters 4-6), certain aspects had clearer, more wide-ranging benefits, beyond just cost savings. Supporting these could be beneficial for net zero on the islands and wider UK.

8.1.1 The importance of demand-side measures

The trade-offs between scenarios should be considered in the context of UK energy policy and the modelling work which informs it. Policy in the UK has generally focused on supply decarbonisation (Section 2.5.2). Results show though that commitment to demand-side policies and focus on achieving targets (remembering the BAU and Export demand scenarios consider the historic achievement of existing policies, not their targets - Section 4.6) could have wide ranging benefits. These would make investing in efficiency a low-regret option, irrespective of other technology decisions.

At the individual level, greater efficiency could result annual electricity bills £600 lower per household or business. Heat pumps will be the key technology to enable this, combined with building fabric upgrades, but other categories such as appliances and lighting could also contribute. Savings made in industry could have a notable effect on average demand and so the overall size of energy system. Granted, actual savings could be lower due to the rebound effect, but upgrades to buildings and heating technologies specifically would result in other benefits not modelled, such as warmer homes and improved health outcomes (Citizens Advice, 2023). The distribution of costs and changes to bills also demonstrates the importance of targeted policies to ensure a “just transition”, but with high proportions experiencing increased electricity bills from electrification, wide-ranging measures will be needed.

There are also benefits at the systems level. Peak demand (a key factor influencing overall cost of energy supply) could be halved between the two scenarios of policy achievement (including distributed generation). Heat pumps will again be critical, with potentially 2 kW of peak demand reduction per household compared with direct electric heating. With the additional flexibility and distributed generation in the Net Zero model, peak demand would be nearly a third (200 MW for BAU and Export vs 78 MW for Independence). Reducing local demand allows the islands to export electricity more frequently and as a greater proportion of the total generation. For the islands, demand flexibility has a clear role in reducing curtailment and maximising export of low-carbon electricity which should be maximised. This would apply even during the low-wind winter and to the export of hydrogen - despite Independence having lower electrolysis capacity than Export. The Independence scenario also has the highest electrolysis load factors - up to 69% in the summer high-wind month, which would significantly reduce the cost of hydrogen. Reducing demand appears to increase how often excess generation can be used to produce hydrogen, an efficiency benefit not been observed elsewhere. Reduced demand also lowers network stress, with lines spending less time at peak capacity, facilitating increased energy export and reduced curtailment. The Governments action plan to speed up network upgrades highlights steps required but nowhere does it emphasise the role that reducing peak demand can play in minimising network stress (DESNZ, 2023j).

The structure of the model presented in this work highlights how future energy systems models can be improved with regards to demand modelling. In most energy systems models, including the UK Governments, demand is either modelled independently (with conclusions separate to the whole-systems effects) or as an exogenous input. The detail of modelling in this work, which is combined with a whole-systems model, results in a different emphasis in results. Combining the detailed understanding of the multiple benefits of demand with the structuring of costs and benefits of net zero highlights that a more demand-led transition could have more equitable outcomes for society. Greater prominence of demand modelling, not just on its own but as part of whole systems modelling frameworks, could alter the ‘optimal’ approaches to decarbonisation as determined by those models. This is not to say that the importance of other decarbonisation aspects is over-stated, for aspects like decarbonising electricity supply are obviously vital, but more that the relative importance and urgency of demand-side measures could be raised. Net zero is an opportunity not just to mitigate the effects of climate change but could also transform energy systems and how the benefits are distributed throughout society. Simpler (but not less comprehensive) frameworks to understand the wide-ranging effects of efficiency, other than just saving energy, are essential to this given the computational complexity of the demand model developed in this work. Incorporating these additional benefits into systems models that inform policy decisions could lead to improved outcomes overall.

8.1.2 Maximising the energy from biowaste

Modelling the cost of biogas-from-waste highlighted several key factors and demonstrated the plurality of solutions specific to the context of each region. The availability of waste, the type of waste, collection costs, facility configuration, and generation technologies all influence how much biowaste could economically be utilised for energy.

Incorporating a much more detailed collection cost methodology than other techno-economic models has demonstrated that while it did not significantly improve a simplified straight-line approximated travel distance, vehicle allocation can be significantly improved. Collection costs varying widely from £0.1-1670 /tonne highlights how simplified mass-based metrics are inappropriate for poorly connected regions. A power-law relationship (Section 5.7.3) identified between participation rate and unit collection costs could be adapted by local government to assess schemes for improving uptake. Overall, the detailed collection cost method was more technically involved, but provided much more insight than a simplistic methodology.

Addressing the main factors affecting the energy costs could encourage anaerobic digestion for producing biogas. Considering avoided costs demonstrates that economic feasibility for the islands relies on minimising collection costs. Despite this, incorporating additional waste streams could reduce the biogas costs for certain industrial-only facilities, demonstrating that the additional energy potential can in some specific cases offset additional collection costs. Mixed waste streams have the potential to reduce the cost of energy and so should guide future anaerobic digestion research. Capital grants greatly improved how much biowaste could be utilised, so could be crucial to improving resource utilisation, particularly for centralised waste collection facilities with higher collection costs (Figure 5-9). Co-location with industrial heat demand was generally the most economic, but elsewhere other heat demand could be more applicable.

It is not clear from this research what the main barriers are to the development of biogas potential is for the islands. This is particularly so for the industrial sector, where the estimated cost of biogas is in many cases much lower than alternative technologies. The elasticity of fuel-switching to hydrogen or biogas for industrial users was not modelled, but gas boiler costs were used as a cut-off for economic viability. If heat from hydrogen costs are higher (FES estimates hydrogen prices of 12-35p/kWh (National Grid, 2023), compared with 10-year averaged natural gas prices of 2.5p/kWh) (BEIS, 2022c), the economically viable energy from biogas could be underestimated. The cost of heat from locally sourced biogas is more controllable than international or regional hydrogen markets, indicating that investing in local biogas could insulate businesses against uncertainty in fuel prices as they move away from fossil fuels. The clearest role for biogas in modelling of the islands seems to be replacing heat demand otherwise provided by hydrogen.

Incorporating the additional resource circularity into the model introduced additional complexity but highlighted how these traditionally non-energy resources could have a role in decarbonisation, particularly with regards to sectors less suited to electrification. This could help to insulate against the uncertainty around hydrogen whilst also helping to stimulate local industry to support it. The overall contribution of biogas for the islands, which significant bioresource-based industries relative to local demand was small. However, the LCOE improving in some cases with a wider range of waste streams (Figure 5-8) highlights the importance of a modelling approach which captures the local or regional details which could influence the price of energy for biogas or other localised energy sources. The need for further work understanding the biological processes of co-digestion is also highlighted as needing further work to improve understanding of its true potential as a fuel for net zero.

The sensitivity analysis of incentives and avoided costs highlighted that smaller, distributed facilities are more dependent on these additional incomes for the facilities to be viable. If biogas is desired as a solution to minimising waste and emissions, this highlights that financial support is essential if the collection costs are too high. Indeed, this is reflected it the Scottish Governments current exemption from food collection for rural areas, which demonstrates recognition of the additional difficulties facing remote regions but does not offer support. If biogas is to form part of decarbonisation plans, more support will be needed than that offered in the government’s biomass plans.

8.2 Whole systems trade-offs

Other aspects of the Net Zero model are more dependent on assumptions and conditions external to the scope of the model. These could depend on the wider UK energy system (modelled as consistent across all scenarios), national and international energy markets, and the direction of technology development.

8.2.1 Scope of electricity network upgrades and balancing net zero

Scenarios compared methods of utilising excess island renewable energy, but only BAU included network upgrades - Export used electrolysis and Independence combined this with efficiency and flexibility. Whereas demand benefits are scalable, the scope of network upgrades is less clear and more specific to the islands.

The modelled upgrades to electricity networks are the largest single category of capital costs, but this depends on several uncertain assumptions and cost metrics. With lower efficiency gains, the BAU and Export scenarios had unserved energy for some islands, with networks only upgraded to address generation curtailment. Sensitivity analysis of network capacity for the Import and Export scenarios showed that although greater network capacity has a clear role in reducing curtailment and increasing electricity exports, it can also be provided by other local demand flexibility or electrolysis. At the upper end of network costs, alternative solutions would be more economical, which would surely incentivise these alternative solutions provided the right market mechanisms were in place to support them. This could involve efficiency, DSR, or BESS, which all reduced peak demand and imports for the Independence scenario. If network costs for the island were at the lower end, network upgrades could be more effective. This trade-off will be essential to managing the overall cost and impact on local communities caused by renewables and demand electrification.

In the UK, there are currently three transmission and fourteen distribution network operators, with Ofgem overseeing proposals for expansion based on needs cases. The anticipated FSO should take a more holistic approach considering future demand, generation, and the integration of electricity with hydrogen markets (National Grid, 2023). Achieving an optimal network configuration requires consideration of the widest range of technology options in making investment decisions. The Governments assessment of network upgrade costs highlights that 15 GW of DSR could reduce system costs by £40-50 billion (BEIS, 2022a), but distributed options are not considered as inputs to systems modelling. Whilst admittedly demand-side measures are less controllable (a generator is more predictable than encouraging people to use less energy) it should still inform policy design from the Government's systems modelling. If network operators or the forthcoming FSO were regulated to include assessment of the widest range of technologies, alternative outcomes might be achieved with greater benefit to households and businesses.

Although not directly comparable with the islands, the scale of network upgrade costs reinforces the vast scope of upgrades to the UK network needed to facilitate increased electrical demand and greater generation capacity (National Grid, 2023). Ofgem has understandably taken an approach that network expansion should minimise consumer costs, but this has resulted in two-decade long negotiations for guaranteed Scottish island generation capacity. New lines built will be immediately at capacity, without room for further development. Although the Government targeted halving the 14 years it takes for new network capacity to enter operation, whole system management is deferred to the FSO when it is eventually set up (DESNZ, 2023j). Continuing a piecemeal approach, where new lines are immediately at capacity and new generation takes (at best) seven years to connect, will surely lead to a struggle to achieve a decarbonised electricity system by 2035.

Results show that net zero will increase complexity of network balancing. Electrolysis capacity connected to distribution networks increases time spent at peak stress, both in utilising local excess renewable generation but also importing from the mainland. This will need balancing within local network constraints if not directly connected to specific generators. Whilst the transition from DNOs to distribution system operators (DSO) is ongoing, SHEPD (the islands network operator) is some ways already fulfilling this role through the ANMs on the islands, which were set up to manage additional generation within grid constraints. Despite this, SHEPD was unable to provide network capacity data for this study, which had to be approximated (Section 6.1.3). Balancing net zero distribution networks will require real-time understanding of thermal limits. For example, digital dynamic line rating (DLR) devices could help improving understanding of grid capacity and maximise network utilisation (Carey, 2024). The Governments hydrogen roadmap implies the FSO would be responsible for planning (DESNZ, 2023g), but the day-to-day management of balancing involving electrolysis it is not clear. The same goes for clarifying the role of DSR and other flexibility options - network operators should be empowered to support these measures rather than rule them out due to their complexity.

Although the islands have been modelled in greater detail than the mainland for the Net Zero model, some important observations can be made. Scotland is, and will continue to be, a net exporter of energy, with conditions facilitating generation that exceeds demand. However, development of generation capacity is already limited by transmission capacity to reach demand further south. When generation is high at the extremities of the UK network, the islands contribute to constraints down the length of Scotland (National Grid, 2018). This means that on top of constraints modelled for the islands, island generation could exacerbate the existing mainland Scotland constraints which are not modelled. If it is feasible for the islands (discussed in Section 8.2.3), the value of island electrolysis in reducing curtailment is underestimated if electricity exports are lower due to grid constraints not modelled. This highlights the importance of spatial resolution in modelling net zero energy systems. Flexibility options like V2G charging will be critical in reducing curtailment (National Grid, 2023), but if demand is geographically separated from generation, then effectiveness will be reduced - EVs in London are unhelpful for grid constraints in the north of Scotland.

8.2.2 Diverse and distributed generation

Scenarios of generation capacity consider the trade-off between larger, transmission-scale capacity and smaller, distributed generation. Whilst they are not exclusive, it highlights the focus of Government policy on larger technologies. Whilst critical to achieving net zero, like any large infrastructure project, community acceptance could impede development, particularly given the scale of generation required nationally.

In the Net Zero model, large generation (>50 MW) was connected to the transmission network, not necessarily at the node it was physically located in. This highlighted that large local generation projects do not necessarily benefit those affected by them, which has been a focal point of opposition to wind in Shetland (Carrell, 2015). The Government recognises this in updating the criteria for CfD allocation to include measures of community support (BEIS, 2020a). At the scale of generation required for net zero and for interim targets such as power sector decarbonisation by 2035, minimising disruptions to deployment are crucial. Reliance on larger generation will increase the need for expensive network upgrades. The holistic approach of the Independence scenario demonstrated a reduced reliance on network upgrades and large-scale generation, this will help minimise objections to more disruptive infrastructure through distributed technologies.

Distributed generation could complement large-scale generation in this sense. Results from the Independence scenario allow the islands to export more energy, increase electrolysis load factors, and reduce bills for households (Figure 4-25). Research has however shown a persistent inequality issue in terms of who benefits from renewable subsidy support (Stewart, 2021). With the Government's ending of FiT support for distributed generation based on the view that the market for distributed generation is mature (BEIS, 2018c), benefits are out of reach for many, with policies targeting specific income groups failing to deliver (CCC, 2023). Community ownership, particularly in the islands but also more across rural Scotland, has been demonstrably successful and benefitted surrounding areas (McHarg, 2015; Okkonen and Lehtonen, 2016; Fuentes González, Sauma and van der Weijde, 2019). Energy Communities, which facilitate collaborative investment in local infrastructure and are supported by the EU Commission (European Commission, 2023a), are an approach not yet supported by the UK Government. The Government provided billions in energy bills support during the energy crisis (Maximov *et al.*, 2023), so why not support reducing bills for the those in fuel poverty through distributed generation. Policies like the Californian low-income weatherisation programme provides solar-PV and efficiency measures to low-income households at no cost (California Department of Community Services and Development, 2022). This could similarly support small-scale generation in the UK and minimise the costs of the net zero transition (demonstrated by modelled changes to bills) for households least able to afford it.

This modelling of distributed generation and network does not however capture the individual building level distribution network limitations which could be impeding the deployment of generation. The modelled capacities of distributed generation could therefore be exaggerated, however, the modelled capacity for Orkney is actually exceeded by current FiT deployment (Section 6.5.2). Localised network constraints can only be assessed on an individual basis, but the example of Orkney indicates that solutions can be found to enable greater distributed generation capacity if desired.

The geographic and supply diversity of island generation comes at a higher cost, as evidenced by higher CfD prices for island generation (DESNZ, 2023c). Island wind requires longer, more expensive transmission links than offshore wind in the southern North Sea, and marine energy is not only much less mature but also operates in a more hostile environment. These additional costs can however be offset against benefits shown in the results. The Government's position on CfD allocation has been to support projects where they can reduce costs for consumers (reducing the cost of capital via project risk) or demonstrably provide other benefits to local communities (BEIS, 2020a). With commitment to categories for remote island wind, tidal stream, and wave, it has recognised the benefits of diversity, which should be continued to help ensure a more resilient net zero generation system.

8.2.3 Questions about the role of hydrogen

Perhaps the biggest uncertainty in the Net Zero model is how hydrogen (or hydrogen-based fuels) could feature in net zero for the islands. Results are highly dependent on some of the key assumptions (Section 3.3), particularly around the sectors of demand, types of suitable storage, fuel transport costs, and future fuel price uncertainty.

Modelled line flows demonstrated that electrolysis could place additional stress on island networks, through both using local generation and importing electricity. It has been stressed elsewhere that co-location of production with demand would be more economical for initial hydrogen production projects (National Grid, 2023). If however electrolysis is used to produce this hydrogen, modelled results here indicate co-location with the electricity capacity is also crucial to minimise network stress and maximise curtailed electricity utilisation. If this is not possible, or even when it is as demonstrated by higher electricity imports for electrolysis, balancing the grid will have additional complexity as indicated by the greater time spent by networks at peak stress in the Export scenario. Responsibility for this should be clarified by DSOs and the under-development FSO, as network loading could be a major barrier to electrolysis deployment. Generally, results support the Governments creation of the merging of electricity and gas responsibilities in the FSO, which should also be done in developing energy systems models which inform decisions about structuring markets and policies.

Whether small-scale hydrogen capacity can utilise excess renewable energy will depend on several factors. Economic feasibility depends on the trade-off between transportation and storage costs, losses in economies of scale for smaller production, and how competitive electrolysis is with other means of producing low-carbon hydrogen. Other liquid fuels may be more straightforward to transport to remote areas than pure hydrogen, but if made with additional steps from the same low-carbon hydrogen feedstock, they will always be more expensive than pure hydrogen itself. The optimal balance for the islands of local production or imports will depend heavily on these factors. Sensitivity analysis of the cost of hydrogen produced indicate that locally produced hydrogen could cost the same or less than BEIS cost modelling for equivalent technologies, and much more so if non-pipeline transport costs were included. The much greater cost to transport hydrogen by other means highlights that unless cheaper transportation means are developed that do not rely on fixed infrastructure, hydrogen is likely to be unaffordable for regions without this hydrogen transport infrastructure.

Further clarity is unlikely until more hydrogen supply and demand is developed, particularly for smaller, more remote regions. Costs for the modelled liquefied hydrogen storage could be significant, indicating either a need for technological improvement or else by minimising hydrogen storage requirements (where cheaper geological options are not available). Hydrogen storage is also not modelled with any error margin, so if the modelling of worst-case weather for the UK does not align with the islands worst-case, hydrogen storage sized to meet winter demand will be underestimated. Further work with detailed modelling more technologies and hydrogen storage costs is needed.

The business case for small-scale electrolysers is also unclear. Producers need to be matched with consistent and guaranteed demand (if cheaper non-pipeline transportation options are not available), which likely makes the modelled electrolysis supply for each node overly optimistic. Electrolysis for each region would allow larger groupings of demand and so reduced risk for the suppliers. Hydrogen demand mapping highlighted several clusters and demand types which could be ideal for developing local electrolysis capacity with consistent demand. Whilst categories like agriculture or freight might be less certain, distilleries (Islay and Jura) or ferries (Na h-Eileanan Siar, Shetland, and Orkney) are more fixed. Ferry demand between islands (mainland ferry demand was not modelled- Section 4.3.2) could be an excellent source of demand met by local electrolysis. Ferries at end-of-life could be replaced with hydrogen equivalents, with electrolysis capacity (ideally located near to harbours and/or generation) scaling up to meet a growing demand. This could take the form of a hydrogen fuelling station with on-site electrolysis, per road transport examples in China (Hydrogen Insight, 2024a). Policy support targeting small-scale, localised electrolysis could help to reverse deindustrialisation and depopulation of remote areas, creating jobs and fostering supporting industries. If non-pipeline transport costs for hydrogen are too high, it would support the case of localised electrolysis. This could be targeted where hydrogen producers can demonstrate additional benefits to local regions beyond energy production. Existing competitions cover industrial demand (Industrial Energy Transformation Fund) or supply of hydrogen (Net Zero Hydrogen Fund) separately and exclude funding used for the other. Given the synergies highlighted through co-locating supply and demand, combining or expanding the scope of the funds could help support more optimal projects. Ultimately though, as shown in the sensitivity analysis, if hydrogen cannot be locally produced, the cost will be prohibitive and other fuels (likely electricity) will have to be used.

Government modelling of hydrogen production costs found the cheapest green hydrogen technology to be electrolysis with excess renewable generation, but this depends on several assumptions. Noting that increased load factors would reduce the cost of energy, a load factor of 25% is assumed (BEIS, 2021a). Net zero modelled electrolysis co-located with generation had minimum load factor in the worst-case winter month of 28%, increasing to up to 69% in the summer. This could however be because electrolysis capacity is undersized relative to island generation, or that curtailed electricity is exaggerated on the islands relative to the rest of the UK. The report also assumes curtailed electricity to be available at no cost, which seems unlikely under the current system curtailment payment structures. If curtailment payments remain an issue, where electrolysis helps to reduce their cost could warrant financial support as flexibility mechanism, but this would depend on the wider payment structures.

The price of hydrogen for the islands could be as low as £62/MWh (including the market rate for renewable generation), 15% lower than the cheapest green hydrogen (including an electricity cost) and 12% more expensive than the cheapest blue hydrogen (without transport costs) (BEIS, 2021a). If non-pipeline transport costs are factored into the price for other sources, locally produced hydrogen would be the cheapest, even if the price of natural gas for CCUS methane reformation was zero. Local production would come at a much greater complexity however, which might not offset the reduction in costs if the business case for hydrogen is not clear enough. If they price of imported hydrogen is too high, it seems more likely that it would encourage electrification of the demand modelled here, where possible. More work modelling the costs of hydrogen production under different load factors and prices of electricity are needed to understand the relation between electrolysis capacity, demand, and generation, particularly for the design of markets and incentives which needed to support this sector if it is to have a significant role in net zero.

Results highlight that annual resolution modelling would be insufficient to capture the availability of excess generation that is crucial to determining what the optimal capacity of electrolysis could be - if it is viable at all compared with other production methods. Results showed grid constraints to be key in maximising electrolysis efficiency, but it is not clear if the Government modelling captures this. Failing to estimate cost, location, and specific low-carbon hydrogen production methods will have implications for investment decisions and policy support, which are more critical than ever during the nascent stages of the industry.

8.3 How are costs and benefits distributed?

Transitioning energy systems to net zero and away from two centuries of fossil fuel dependence will be costly but could come with a range of benefits. Rather than optimising pathways based on uncertain data and assumptions, scenarios in this study were set up to compare outcomes, including how costs and benefits might be allocated between consumers, businesses, suppliers, network operators, and government. Obviously private capital will be needed to achieve the scale of investment required, but it requires strategic direction through policies to realise the ambitious systems changes needed to reduce emissions and combat climate change. It also implies a balancing of desired outcomes: governments might prefer to avoid political risk in choosing technologies; industry would be happiest with their own respective technologies maximally subsidised; and households could vote for policies that do not increase their bills. This model has been set up to consider the trade-offs at a whole system level, but the same results could be interpreted differently by stakeholders such as Government, system operators, or local communities affected by infrastructure projects. Considering and balancing all these viewpoints is an essential feature of a democratic society and is crucial to an equitable net zero transition.

Therefore, there are implications for how costs are ultimately allocated to households, businesses, taxpayers, or bill payers. By comparing the model's scenario results in this context, there are clear divisions between the two with greater focus on demand-side measures (Independence and Middle Way) and the two supply-side ones (BAU and Export). This does not suggest any scenario would be more or less optimal but considers the distribution of benefits and hypothesises the effects on the likelihood of achieving net zero. Results of this modelling cannot definitively demonstrate whether certain approaches might be supported by the public, but it can be comparatively analysed to broaden understanding of the differences between scenarios.

The results show demand-side policies have benefits at all scales. However, a major issue not discussed is financing and particularly their redistributive nature. Scaling of costs to better reflect mainland population balances showed that demand side costs could exceed supply side ones (but again, this does not capture additional benefits or changes to supply costs). Unlike supply side measures, demand measures cannot generally access private capital so must either be paid directly by households/businesses, government (through taxation), or energy bill charges. Whilst the former works for those able to afford it, improving the efficiency of the remainder makes changes reliant on government support or bill charges, both of which make efficiency policies redistributive. Against a political climate of austerity and generally minimising government presence beyond the energy sector, implementing these policies becomes much harder politically. Monthly installations by ECO, the main household efficiency policy for the last decade and funded through regulated bill charges, have steadily declined to less than a tenth of their 2014 peak (CCC, 2023). While modelled results stress the wide-ranging benefits of demand side policies, they do not address the political unpalatability in the UK of their redistributive nature. To meet EU mandated energy savings targets by 2030, France has steadily increased targets for its white certificate scheme for trading energy savings (ENSMOV, 2020). This policy consistency and commitment can be key to success (CCC, 2023). Policies which leverage private capital to invest in energy efficiency measures or generation could help encourage demand-side investment but also require the political will to set up in the first place.

Private capital is much more readily available for the supply-side measures needed to achieve net zero. Initial costs and project risks are borne by investors but recovered through sale of energy or use-of-service charges over project lifetimes (which are more guaranteed than the potential return on reduced energy bills, which as shown by the rebound effect can be harder to predict). There are no further benefits to wider society, aside perhaps from localised infrastructure payments - energy access can hardly be described as a benefit when it is taken for granted. Government commitment is also needed to facilitate private capital investment, particularly net zero by creating markets for new technologies, such as support schemes like the CfD which reduces project risk. Government responsibility and support is on a far lesser scale relative to that required for demand-side policies. A focus on mainly supply side policies might be related to the fact that they tend to be funded by regressive electricity bill charges (easier to achieve politically than direct taxation – a shining example being the Regulated Asset Base model proposed for new nuclear) (National Infrastructure Commission, 2019). This can surely be related to the political desire for the smallest intervention of Government possible in energy markets.

While this might seem tangential to the technical modelling of this thesis, it could have consequences for the political acceptability and public supportiveness of net zero (but again, this is to speculate and cannot be demonstrated by results). Maximising political support will surely improve the chances of achieving net zero. The public is now generally supportive of policies addressing climate change, particularly where they support households, regulate businesses, or invest in the UK (though generally less when perceived to limit behaviour) (CCC, 2023). However this support should not be taken for granted. For example, pushback against the ULEZ in London, had a clear effect on by-elections results (BBC News, 2023). There is a clear link between the successful use of ULEZ as a wedge issue to gain votes and the rolling back of the boiler phase-out target - referred to by an ex-environment minister as a “rural ULEZ” (Carbon Brief, 2023). While the resultant political opportunism might appear isolated, it is based on the experiences of everyday people living with policies poorly designed to support those who most bear their consequences, which should be addressed in policy design. “Proportionate universalism” refers to actions addressing inequality where the intensity is proportional to the degree of disadvantage (Marmot, 2010). The same approach is needed with net zero policy to ensure the widest cross-section of society and voters can support it. With respect to the overall structure and vision of net zero, maximising the distribution of its benefits through demand measures will surely also improve overall support.

8.4 Changes and investment pathways to realise net zero for the islands

Scenarios of different net zero technology configurations for the Scottish islands have been described. These are intended to illustrate potential outcomes; understand how achievable, feasible, or desirable each could be; and what steps would be required to enact them.

In terms of the various modelled aspects, the modelled increase in generation and mainland interconnector capacity will likely be achieved by 2030. Upgraded interconnections are either under construction (Shetland and Orkney) or planned for with even larger expansion (Western Isles - upgraded from 600 MW to 1800 MW with new offshore wind capacity) (SSEN, 2022b), making up two thirds of the modelled network upgrades in the non-BAU scenarios. Similarly for generation capacity, the 1.3 GW modelled in the Independence scenario is already either operational or under construction in the REPD in the local authorities of Orkney, Shetland, and Na h-Eileanan Siar only (BEIS, 2022d). This capacity has largely been awarded CfD contracts though in conjunction with there being sufficient interconnection capacity to transmit electricity to the mainland. Under the current policy environment, any further generation capacity would therefore require further mainland interconnection expansion before development was agreed. To facilitate the decarbonisation of the electricity system in the early 2030's, massive expansion of renewables and network infrastructure will be needed. Therefore this investment would be needed as soon as possible to meet net zero goals, e.g. front-loaded as much a possible rather than spread out over the next 20 years. This outcome makes island generation and interconnections interdependent on each other, as per the BAU scenario, which repeats the historic paradigm of a cause-and-effect dilemma for the network operator in investing in transmission infrastructure.

Other areas (Inner Hebrides, Arran, and Bute) have hardly any capacity planned, possibly due to a less significant wind resource (being less exposed to the Atlantic) or stricter land use restrictions. Achieving the modelled growth in distributed generation would require more changes. Orkney already has a distributed generation capacity exceeding that modelled, but other regions are behind. The reasons for this are unclear - whether favourable local planning laws, a supportive community, or other factors are required - but conditions are clearly more favourable on Orkney. Local and national government support would be needed to encourage distributed generation and match the scale of deployment of Orkney elsewhere. Similarly to large-scale generation, the technologies are readily available and could be deployed as soon as possible to help achieve the shorter-term target of electricity decarbonisation.

Currently energy demand users close by to generation infrastructure do not receive preferential treatment in energy prices. An alternative model that would completely alter this and investment pathways for the islands is inherent to the non-BAU scenarios, which encourage solutions like local flexibility, BESS, or electrolysis to deal with excess generation (instead of transmission infrastructure). If there were a change to an electricity market structure such as LMP, excess local generation would result in lower electricity prices, which in the shorter term could alleviate the high rates of fuel poverty and encourage the energy intensive industries. The reduction in electricity prices could disincentivise further generation capacity though. This type of investment in local demand could occur as soon as market reform was enacted. Lower electricity prices could have the effect though of disincentivising efficiency expenditure, excluding the non-financial benefits discussed.

In the longer term though, when or if green electrolysis and demand for hydrogen takes off as sector, this could also encourage further investment in renewables. The islands have some of the best onshore wind capacity factors, which considered in isolation would be enough to encourage further generation capacity beyond that needed to decarbonise the electricity system. This would be highly dependent on several key factors:

- Changes to market structure, including the pricing of curtailment (and whether generators are able to prefer these payments to those for electrolysis) and what price the electrolysis pays for electricity. LMP would likely have a significant impact on this be encouraging local demand.
- How hydrogen markets develop in the next 10-15 years. The Government has set out a role for hydrogen in decarbonisation, but the exact extent and how it would involve remote communities like the islands (if at all) is very unclear currently, but they are unlikely to be considered until the sector is more self-sufficient.
- The balance of greater transport/storage costs, the reduced economies of scale for the islands, and improved availability of low-carbon generation. If hydrogen transport costs make any remote application of it unfeasible, the perhaps local generation could be more suitable, but this could also encourage other technology options not modelled here for hydrogen demand (such as high temperature heat pumps for industrial applications).

- Islands electrolysis being co-located with renewable generation could help to minimise the burden of balancing local networks, but whether this would be considered in the planning of local networks is unclear. Purchase agreements between generators and electrolysis would further encourage this but again highlight uncertainty about the payment structure of green hydrogen.

These aspects are combined with the facts that hydrogen will take a significant amount of time (likely at least a decade) to mature and that there are limited (to none) requirements for the types of demand assumed to be replaced with hydrogen in this thesis to decarbonise in the near term. Therefore, investment in hydrogen infrastructure will be required from 2035 onwards.

However, as the islands already have several projects demonstrating local electrolysis, the above market developments (especially LMP), the islands could be a suitable location for the early-stage development of the technology that will be needed. Given the need to co-locate demand with supply, a potential example could be the ferries, which have a consistent, predictable demand. As vessels reach the end of life, they could be replaced by hydrogen versions, with electrolysis capacity gradually scaling to meet the growing demand which could include other adjacent sectors such as heavy land transport. Developing small-scale electrolysis capacity, particularly in the early stages of the nascent industry will require sustained support. Combining all of the above aspects would make the best business case for investors and help to develop the local industrial capacity.

Separate from the three main interconnections planned or under construction (modelled for all four scenarios), additional network upgrades are modelled in the BAU scenario. Given how long plans for the three main interconnections have taken to develop and that Ofgem has refused to factor in additional capacity for future development (Ofgem, 2020), it may be less feasible to expect further network capacity expansion. For modelled nodes with unserved energy, the prohibitive cost of network upgrades would likely make investing in alternative demand-side or flexibility systems more plausible, if the DNO allows additional demand on the system at all. Expansion of renewables has also been enabled through the ANM systems, allowing greater capacity but also higher curtailment. Further growth of renewables under these schemes seems unlikely but could encourage alternative uses of the excess energy, such as electrolysis, which the Orkney ANM already has. The increased deployment of renewables modelled from projects with agreed planning permission would likely require certain changes. Ofgem would have to relax its condition of network upgrades requiring guaranteed generation capacity. Excess network capacity would be needed for future expansion or development of newer technologies such as marine energy.

Alternatively, there would need to be a stable market for distributed electrolysis of hydrogen (per the Export and Independence scenarios) to utilise the energy produced.

In terms of local flexibility, the conditions for supporting development are good, as demonstrated by existing projects. Excess renewable generation, low demand, and limited appetite for expanding interconnections makes them ideal locations for trials such as a P2P energy trading scheme (Keay-bright, Elks and Chapelle, 2021). These measures and others enabled by demand digitalisation will likely continue to be encouraged by the conditions of the islands with respect to fuel poverty and curtailed generation. Clear regulatory frameworks for newer measures, particularly DSR, are needed to ensure that they can be optimally deployed to support grid stability, renewable integration, and enable reduced bills. Success of the national trial of the Demand Flexibility Service in 2022/23 indicates support for DSR which should be built upon. Electrification of demand and more renewables mean the complexity of managing the electricity system will likely increase, further increasing the utility of flexibility services. With plans to completely decarbonise the grid in the next ten years, investment in flexibility would be needed as soon as possible, particularly in the context of record curtailment costs with each passing year.

Scenarios were set up such that the BAU and Export demand scenarios were reflective of the current policy implementation. Unless successive governments have very different priorities (and budget priorities, as discussed regarding the redistributive nature of efficiency policies), it seems like these higher final demand cases are more probable. Results show that without improved efforts to reduce demand, more spending on networks or localised storage would be required. For the islands, this would mean lower thermal comfort, higher energy bills, and more disruptive infrastructure. The capital-intensive nature of efficiency measures means that unless energy prices increase dramatically, policy support would be needed to improve demand reduction and outcomes for local households and businesses. The nature of demand-side technologies and the high capital costs would make investment more feasible to spread out until 2045. Given the distributional issues highlighted by the demand modelling in this thesis, immediate term support should be focused on those most affected by (e.g. least able to afford) decarbonisation targets.

8.5 Contribution, limitations and future work

Before concluding this thesis, this section will highlight how it has addressed the research questions from Section 1.3, how it has contributed to the literature, summarise major limitations of the model, and how the work could be continued in the future. Regarding the three research questions, this work has addressed them as follows.

(i) What could net zero energy systems configurations for the islands look like?

The thesis has demonstrated how the islands could achieve net zero within the solution space of the National Grid's FES. Whilst this captures a range of possible outcomes in terms of technology deployment configurations for the islands, it only does so for four deterministic scenarios within the confines of the FES, the assumptions described in Section 3.5, and the technical constraints of the islands (e.g. available renewable capacity). The demand and biogas models have been developed with a level of detail that allows for more in-depth consideration of the impacts of net zero on the islands, like the change in energy bills (Figure 4-25) based on efficiency policy projections (Section 4.6) which are not apparent in more energy systems models with demand as an exogenous input. However, given the time- and data-consuming nature of 100% sample demand modelling (Figure 4-1), this has precluded more detailed modelling of technology scenarios or a wider range of technologies than included in the FES. Other technology outcomes could be just as plausible, but irrespectively of what technologies are used to meet demand, the main points that commitment to efficiency and local energy sources like biogas can have additional benefits remain relevant (Section 8.1.1 and 8.1.2). As discussed in the sensitivity analysis though (Section 7.5), for other aspects- particularly hydrogen (Section 7.5.2)- the results are much more dependent on the assumptions used and so should be treated with greater caution. Whilst it perhaps does not capture the widest range of or the optimal outcomes between the four scenarios, it does highlight these issues with current approach to net zero.

(ii) How can energy systems modelling incorporate circular economy considerations in the area of biowastes and what role could it have in a net zero energy system?

The development of the bioresources model and the integration of it in this work demonstrate that is well suited to integration with a 100% sample demand model. This provided the basis of the resource availability dataset, considering the domestic, commercial, and industrial waste sources of the islands (Section 5.2). This existing framework of every building and its occupancy on the islands (Section 4.1 and 4.2) allowed for the bioresources model to easily capture the local contexts which made up the huge range of production costs modelled, which general framework would not capture. This consideration of the local contexts (Section 5.3) it therefore essential for inclusion of circular economy principles, particularly for bioresources where their nature makes them unsuited for transport (excepting perhaps where finished products could be more easily transported). The role of the specific strand of circularity modelled here (bioresources for biogas) for the islands is limited in coverage, but in specific areas could play a key role in decarbonisation. Combined with greater efficiency (Independence scenario), it could provide a maximum of 10% of the total energy demand, but this masks the regional intensity which is highest for industrial clusters (Figure 5-5). Decarbonisation of industry or other sectors co-located with demand is therefore likely the best suited role for biogas (Figure 5-6). That the cost of energy was in some cases improved with more diverse waste streams though (Figure 5-8) (combined with the potential for improved yields from co-digestion) highlights that this potential could be defined by the ability of waste-producers to co-operate, which will be dependent on policy and regulatory support for the sector (Figure 5-9).

(iii) What implications does hourly, 100% sample, bottom-up energy systems modelling of the Scottish islands have for energy policies and ultimately achieving net zero?

The inclusion of a 100% sample, hourly energy demand model within the framework of a combined electricity and hydrogen model in PLEXOS demonstrates several aspects. The inclusion of more detailed demand modelling than other examples in the literature highlighted the distributional impacts of various energy policies (Section 4.7). With a greater focus on the demand-side in a whole systems model, the distribution of costs and benefits for decarbonisation (Figure 7-12) demonstrates key difference for their distribution in society. Whilst results cannot demonstrate which is superior, it raises questions about which might be more equitable. It also highlights how the exogenous treatment of demand in many whole systems models (Section 2.1) might preclude this emphasis on approaches to net zero. Better inclusion of demand modelling in whole systems approaches would improve this. The inclusion of additional circularity aspects highlights the role that aspects such as bioresources not traditionally considered in detail in energy models could provide a valuable role in localised decarbonisation where there is a resource available and ideally co-located with demand (Section 8.1.2).

8.5.1 Contribution to the energy modelling literature

From the existing literature, this thesis has presented a range of energy systems modelling methods which build upon prior methodologies. Across the specific aspects described in Table 8-2, several key themes are addressed:

(i) *Improved demand model resolution*: whilst other models have focused on either large samples or high temporal resolution, this work has combined both to represent 100% of whole systems demand at a higher, hourly resolution. Particularly, the inclusion of the 100% sample demand model where other models treat demand exogenously highlights the distributional effects of demand policies and the alternative distributions of societal costs.

(ii) *Accessibility of data*: given the detail and scope of data required to realise point (i), data availability was an issue in the literature. Open-source data was used to facilitate replicability of the method and avoid privacy concerns working with recorded data. Data science methods have been used to enable the combination of free available datasets into synthetic data which is representative of actual system behaviours.

(iii) *Demand-centric, whole systems model*: where other models have focused on sectors separately, detailed models of various aspects of a net zero energy system have been combined in PLEXOS. Putting the demand model at the centre of a whole systems model, rather than as an exogenous input that supply is optimised to meet, highlights the distributional effects of demand policies and their effects on people's lives. The greater focus on demand highlights that net zero could not just be about decarbonising energy supply, but about improving the effects that energy has. The additional inclusion of circular utilisation of biowaste and economic modelling across the whole system expands the scope of previous energy systems models and highlights localised decarbonisation solutions which might be missed out in higher level frameworks focusing mainly on supply-side solutions.

Table 8-1: Summary of the ways in which this thesis has contributed to energy systems modelling literature.

Reviewed literature	*Thesis contribution*
Sectors modelled individually	Detailed modelling of demand, supply, and biowaste presents a more in-depth look at net zero possibilities than more intense focus on supply
100% sample demand model incorporated with whole system model	Greater prominence of demand in whole systems models has different emphasis on results and demonstrates the benefits of demand-led net zero
Focus on energy systems only	Inclusion of circular biowaste utilisation widens the scope of models

Reviewed literature	Thesis contribution
100% sample or hourly models exist, but not combined	Hourly, 100% sample model allows for more detailed assessment of efficiency options. Open-source data makes it reproduceable
Data unavailable for the non-domestic sector	Freely available time use data for occupancy profiles addresses privacy concerns and can be repeated anywhere with similar data
Simple weight-based collection cost metrics	More accurate method using OSMNx, CVRP solver, and DBSCAN clustering to optimise distances and vehicle costs
Focus on single industries or waste streams	Publicly available database of all major biowaste types considers synergies between sectors and can be used for further research
Focus on specific technologies and facility configurations	Techno-economic framework for bioresources allows a plurality of optimal solutions to be considered for the diverse local conditions

8.5.2 Limitations and potential improvements

Modelling is essentially an attempt to predict the behaviour of a system based on parameters which simplify but still capture the required behaviour. No model will ever perfectly replicate an actual system. Wherever recorded data was available, this thesis has compared it with results before making projections. Despite this, several areas highlighted discrepancies with recorded data, data availability gaps, or areas of expansion for the methodology (Table 8-3).

Table 8-2: Summary of model limitations and potential improvements.

	Description	Limitation	Improvement
Net zero model	Similar electricity market structure	LMP could alter island conclusions specifically but also wider UK	Consider a case with LMP as a sensitivity in the modelling
	Only two months of worst-case UK weather due to computational constraints	Worst-case might not align between UK and islands; might omit other behaviour	Weather cases specifically for the islands could be identified and compared
	UK modelled as a single node; Europe not included	Limiting the UK to a single node could alter the balance energy flows to the islands	Higher resolution modelling of the UK and European interconnections
	Balancing, day-ahead, and capacity markets not modelled	This could under-value flexibility options and predictable tidal generation without these additional markets	Add these markets to PLEXOS, but electrolysis operation would be complex
	Costs assumed to be equivalent to the mainland	Remote islands likely have higher costs for almost everything, so they probably underestimate	Specific island cost data for generation, networks, efficiency measures, etc.

	Description	Limitation	Improvement
Hydrogen	Hydrogen-based fuels lumped as hydrogen	Including analysis of more fuels and conversion technologies could have very different results	Consider a wider range of hydrogen-based fuels, storages, and technologies to utilise them
	Only liquefied hydrogen storage modelled	Other technologies could be more cost-effective, particularly given the above	
	Large uncertainty in costs surrounding hydrogen	Total cost of scenarios highly dependent of price of hydrogen, costs to import, local electrolysis, etc	Uncertainty in hydrogen costs is hard to address while technologies are immature
	Only green hydrogen is considered, the origin of hydrogen imported from the mainland in not	Price of green/blue/other hydrogen would affect results, as per the above	
	Only PEM and alkaline electrolysis are modelled	Other production technologies could be more efficient/ cost-effective	Modelling a wider range of technologies could have different implications.
Demand	Lack of non-domestic data	Reduced accuracy of the demand model	Greater availability of non-domestic data
	Datasets used from several years due to time constraints		More recent census data combined with demand should improve accuracy
	Behavioural changes not accounted for		Response to efficiency changes could be accounted for with more work
	Industrial model based on extrapolation of improvements from whisky industry		More detailed modelling of each industry and improvements specific to them
	Fuel switching assumed for categories of demand	Demand for different fuels could be very different and will depend on the price of alternative fuels/technologies	Uncertainty in scope of fuels is hard to address while alternative technologies are immature
Supply	Renewable model tended to overpredict peak generation, which was corrected for	Model could exaggerate peak generation and subsequent curtailment, which would affect results	Further research into the factors affecting estimates of generation and isolation of the over-prediction
	Assumed that all capacity in REPD would be feasible for islands	There could be conflicts between planned projects, which would over-exaggerate the potential island capacity	More in-depth assessment of individual generation projects would be needed to assess this
	Only one scenario of mainland generation included for simplicity	Different generation technology balances could alter results for the islands	Develop and compare further scenarios of generation for the mainland
Networks	Network capacity estimated based on equations and material properties	Modelling of current network capacity could be inaccurate	Specific network capacity data made available from the DNO
	Only main network constraints modelled to reduce complexity	Modelled nodes could have self-contained grid constraints	Further assessment of network capacity would be needed - see below

	Description	Limitation	Improvement
	Very wide uncertainty in network upgrade costs	Different network upgrade costs would skew scenarios results	More detailed power flow modelling of network costs to understand constraints
Biowaste	National food waste factors assumed for households and commercial	Estimates of food waste potential might differ for the islands	Using data more specific to the islands
	No improvement to energy yields due to co-digestion	If feasible, would increase energy yield and reduce costs, if not, LCOE would be similar (no fixed AD CAPEX costs)	More research needed into understanding the mechanisms of co-digestion, particularly at scale

Some of these potential improvements could be addressed with more time, such as more detailed network modelling of the islands or mainland UK/EU. Alternatively, it might be possible to simplify the methodology whilst achieving the same results. The progression of other aspects though is more uncertain. For example, if low-carbon hydrogen can be extracted directly from the ground, it might be produced at a price on par with fossil fuels (Durham University, 2023) (this does not address transport and storage issues however), which would likely make electrolysis much more expensive no matter how cheaply electricity is available. This would eliminate any scope for electrolysis for minimising downsides of grid constraints, therefore increasing the utility of network capacity and other flexibility measures. Similarly, if LMP was introduced, if could disincentivise efficiency measures which were deemed a key output of the model. Scenarios were set up to cover ranging net zero outcomes for the islands, but other solutions could emerge which alter the conclusions of this work.

Whilst two decades ago, some industry figures anticipated a renewable penetration limit of about 30%, but in 2022, the UK was able to operate for 50 hours on 100% low carbon generation - albeit with fossil fuel generation for frequency stability (Staffell *et al.*, 2023). The expectations of how a net zero energy system could work presented in this thesis could easily be proven just as wrong in the two decades until net zero targets. Much of this will be dictated by the political support (both societally and in Government) for net zero and fighting climate change, which no amount of technical modelling can predict.

8.5.3 Generalised insights and replication of the model

The model has been developed for the Scottish islands, but some general implications for remote communities and net zero can be discussed. The benefits of improving efficiency will be similar elsewhere in the world- whether energy bills are driven by heating or cooling, reducing energy consumption can help alleviate fuel poverty (Figure 4-25) and reduce stress on existing network infrastructure (Figure 7-4). The linear relationship between flexibility and curtailment reduction, although skewed by the imbalance of island demand and generation, indicates that greater flexibility capacity than currently (e.g. near zero) could benefit renewable integration, which would likely scale with renewable capacity, but the limitations of this relationship are not clear. The economics of implementing efficiency measures though will obviously vary by region, which highlights the difficulty in generalising methods relating to demand modelling versus traditional supply-focused systems models where costs and technical characteristics are more likely to be consistent across regions. Although many remote areas depend on biowaste producing industries and, indeed anywhere there are people, they will produce biological waste, its significance will vary as a potential energy source in the region. The modelling framework though highlights how local contexts are essential to modelling the value of resource circularity.

On the supply side, development of significant generation capacity is obviously dependent on the technically available resource and existing energy infrastructure. Although the region of this study are islands, they are perhaps unusual in that almost all the populated ones are connected to the mainland UK grid (now that the Shetland interconnection is completed) (SSEN Transmission, 2024b). This has facilitated significant expansion of renewables till now, with further interconnections allowing more large-scale expansion. Fully islanded grids with similarly low demand levels would be much more limited in terms of the capacity expansion and require a much greater emphasis on ensuring security of supply than here where it is provided by the mainland. Distributed generation would be suitable in almost any context to reduce reliance on imported energy though. This highlights the importance of interconnections in providing reliable energy for remote regions, but also as the main facilitator for exporting low-carbon electricity and reducing electricity prices, although the sensitivity analysis demonstrated the same benefits could also be provided by electrolysis or flexibility. An island with higher demand relative to its available resource could develop more generation capacity up to its required demand though. Although in theory electrolysis could be used as a more flexible demand allowing a region to develop greater generation capacity, the results here demonstrate that much more work is needed to understand the economics before it would be feasible. If the economic trade-off between transportation costs and economies of scale is sufficient to encourage small-scall electrolysis as a flexible way of minimising curtailment though, then it could be suitable for other regions.

Adapting the model to other regions would be possible provided there was a similar degree of data availability. The major datasets and their interlinkages are summarised in Figures 3-1, 3-2, 4-1, 4-2, 4-3, 5-1, and Table 6-1. If the same datasets were available for a region, then the same types of data (with different distributions) could be formatted in the same framework. This would entail developing the same sub-models, which obviously would have differing outcomes and potentially conclusions (related to what has been discussed above) and setting the outputs of these models up as inputs to PLEXOS. The most important ones would be time use data, census data, building stock data (including business types), annual business demand (demand model), annual waste production (biogas model), generation capacity, and transmission network capacities (supply model). Evidenced by the longer data requirements list, the main complexity in adapting the model to elsewhere would be in the demand data. This could be heavily simplified based on an average daily curve and simply degree day analysis (as for the mainland in Section 4.4), but this would miss the main point that the more detailed demand model highlights issues of the uneven distributional impacts of net zero on households and the potential additional benefits of efficiency. Generation and other supply side data is more easily approximated from less regional sources, therefore would generally be easier to come by.

What would differ by region would be the emphasis of the sub-models and the attention given to different aspects. For example, consider an island with more commercial demand, less industry, and a greater economic reliance on tourism. Due to the demand model sampling 100% of the islands demand, these are all captured in the existing framework. How important these aspects would be to the validation process (Section 4.5) though would clearly differ. With more commercial demand and less industry, more attention would need be paid to the specific demand sectors (e.g. types of buildings for commercial demand). For this model, the local authority level hourly demand had the greatest error in regions with the smallest populations and highest levels of tourism, but as these were the smallest regions, it was considered acceptable (Figure 4-17). For another region more dependent on tourism, greater effort would be needed to understand how tourism affects demand and how it varies over different time periods. If it was a more significant factor, it would need be considered as a sensitivity analysis of the results. Other aspects that differed might require similar investigation, which could be incorporated into the workflows given in the figures and tables listed in the previous paragraph. The formulation of scenarios and potential technology capacities would obviously need to be informed by the local contexts of the region. The overall structure of the model (e.g. sub-models of demand, supply, biogas – or other localised energy vectors- feeding into optimisation for PLEXOS) though would be the same.

8.5.4 Future work

There are several avenues in which the work of this thesis will be continued and further developed. Data outputs from the demand model will be used in collaboration with the

DISPATCH project, which examines the scope for decarbonisation measures in Orkney. As the model will be used for a smaller geographic area, the model will be updated with more specific data where available and recalibrated. This will be used in modelling of decarbonisation options for the islands and could lead to further use of the model for other island local authorities.

For the first phase of the National Buildings Database project, led by the Building Stock Lab at UCL for DESNZ, a database of the energy demand of all non-domestic building stock was developed for England and Wales. The ongoing second phase consists of expanding the model to Scotland. Several of the demand modelling methodologies developed in this thesis will be integrated with this work.

8.6 Concluding remarks

This work has highlighted the immense complexity of decarbonisation and the transition to net zero. Through various data science techniques, it has improved upon existing energy systems modelling literature to expand the understanding of what net zero could look like and the steps needed to get there. There is still however much uncertainty on how net zero could be achieved and whether it can be achieved on time. The results of this thesis should be considered with this in mind. The cautionary short story entitled “On the exactitude of science” by the Argentinian author Jorge Luis Borges (Borges, 1954) summarised this - due to its brevity, it can be repeated in full:

> *“…In that Empire, the Art of Cartography attained such Perfection that the map of a single Province occupied the entirety of a City, and the map of the Empire, the entirety of a Province. In time, those Unconscionable Maps no longer satisfied, and the Cartographers Guilds struck a Map of the Empire whose size was that of the Empire, and which coincided point for point with it. The following Generations, who were not so fond of the Study of Cartography as their Forebears had been, saw that that vast map was Useless, and not without some Pitilessness was it, that they delivered it up to the Inclemencies of Sun and Winters. In the Deserts of the West, still today, there are Tattered Ruins of that Map, inhabited by Animals and Beggars; in all the Land there is no other Relic of the Disciplines of Geography.”*

The essential point of modelling is to experiment with the defining characteristics of a system to better understanding of how it operates. As the map of the empire relates, it is not desirable or, pragmatically, achievable to completely represent reality in a model. Models are designed to address specific questions so any single model will never provide answers to every question. Whilst models should obviously be designed in an objective and empirical way, they will always be built on assumptions about the future which can never be fully proven until after the fact. Although care has been taken to address these, there are still any number of potential outcomes which could derail the perspective of net zero presented here for the Scottish islands. So much has changed in the energy industry in the last 25 years and so much more will likely change before 2045, whether anticipated here or not.

When the “optimal” outcome depends on inputs which are subject to large uncertainty (not to mention biases in designing models), the “optimal” outputs will similarly vary. Technically feasible scenarios of net zero have been presented here by comparing outcomes not just of technical characteristics, but also how the burden and benefits could be allocated to society. In a democracy, the success of net zero will depend on how (un)popular its implementation is. In an ideal world, political decisions on climate change would be based on rational and evidenced-based decision making, but in reality, they are just that - political.

This thesis has shown that feasible net zero scenarios will require significant changes across energy systems, some of which could be politically unpalatable if the effects of policies are not properly analysed. A more prominent role for demand-side efficiency measures could reduce infrastructure requirements; improve outcomes for households and businesses; increase system resilience; and could cost less overall. Whilst much more generation will be required either way, this could minimise the scale and burden it places on local communities, as well as reduced dependency on imports or uncertain hydrogen replacements for fossil fuels. Greater diversity of generation, both in location and technology (such as marine generation and biogas), could have benefits to whole energy and resource systems. If net zero can be presented, not just as a carbon accountancy exercise, but as a more fair, resilient, and sustainable vision of the future, then maybe this could have the best chances of minimising the worst effects of climate change.

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Appendix A: Summary of major datasets

This appendix summarises the main datasets used in the three sub-models described in Chapters 4-6. As much as possible data, was used directly from the below sources, but in some cases additional data was used which is given in Appendix B.

Table A - 1: Main datasets from the demand model (Chapter 4).

Name	*Description*	*Author*	*Availability*	*Reference*
Time Use Survey 2014-15	10-minutely actions for a day and demographic data of 11,421 people	UK Data Service	Freely available under UKDS End User License	(Gershuny and Sullivan, 2017)
Census Data 2011	Demographic data for Scotland's 56 occupied islands	National Records of Scotland	Freely available	(National Records of Scotland, 2016)
Intertek Household Electricity Survey 2012	National survey recording annual electricity demand by each appliance for 251 households	Intertek	Freely available	(Intertek, 2012)
Energy Performance Certificates	EPCs for domestic and non-domestic properties	Scottish Government	Freely available	(Scottish Government, 2021b)
UKBuildings	Polygons and building type data	Geomni	Available at cost	(Geomni, 2020)
Open Street Map	Polygons and building occupancy types	Open Street Map	Freely available	(OpenStreetMap contributors, 2021)
Scottish Housing Condition Survey 2014-19	Local authority statistics of surveyed building characteristics	Scottish Government	Available under academic license	(UK Data Service, 2022)
UPRN	Unique property reference number's locations	Ordnance Survey	Freely available	(Ordinance Survey, 2021)

Name	Description	Author	Availability	Reference
Building Energy Efficiency Survey (BEES)	Phone surveyed kWh/m2/year and potential energy efficiency measures for non-domestic building types	Department for Business, Energy and Industrial Strategy	Freely available	(BEIS, 2016a)
Google Places	Business opening hours	Google	Freely available within monthly API limits	(Google, 2021)
OikoLab	EP weather files based on NASA MERRA database	OikoLab	Freely available within monthly API limits	(Oikolab, 2021)
Islands demand data	Grid supply point electricity demand data for Scottish islands	Scottish Southern Electricity Network	Available at cost	(SSEN, 2021)

Table A - 2: Main datasets from the biowaste model (Chapter 5).

Name	Description	Author	Availability	Reference
OSMNx	Python package using OSM road network files	Boeing, Goeff	Freely available	(Boeing, 2017)
National Agricultural Census Data Time Series	Agricultural census data for all of Scotland	EDINA	Freely available	(EDINA, 2021)
Fish Farms Monthly Biomass and Treatment Reports	Fallen stock data for Scottish fish farms	Scotland Aquaculture	Freely available	(Scotland's Aquaculture, 2021)
Food processing sites register	Database of food processing sites	Food standards Scotland	Freely available	(Food Standards Scotland, 2022)
Fleet landings by port	Weight and type of fish landed by UK port	Marine Management Organisation	Freely available	(Marine Management Organisation, 2016)
Distillery capacity	Production capacity of whisky distilleries	Scottish whisky association	Freely available	(Gray, 2020)

Table A - 3: Main datasets from the supply and flexibility model (Chapter 6).

Name	*Description*	*Author*	*Availability*	*Reference*
Renewable energy planning database	Database of all existing and proposed renewable projects in UK	DESNZ	Freely available	(BEIS, 2022d)
Sub-regional Feed-in-tariff statistics	Local authority statistics of FiT by capacity and number	DESNZ	Freely available	(BEIS, 2020d)
SSEN network shapefiles	Distribution and transmission network shapefiles	SSEN	Available under academic license	(SSEN, 2019)
Future energy scenarios	Scenarios-based projections of UKs net zero energy system in 2050	National Grid	Freely available	(National Grid, 2023)
BMRS reporting data	Half-hourly demand and balancing actions for the UK	Elexon	Freely available	(Elexon, 2019)
Generation cost report	CAPEX and OPEX for all major generation types	DESNZ	Freely available	(BEIS, 2020b)
Renewables Ninja	Wind and solar PV capacity factors	Pfenninger, Stefan and Staffell, Iain	Freely available	(Pfenninger and Staffell, 2019)
Tidal current capacity factors	Recorded tidal current velocities for Orkney	EMEC	Available under academic license	(EMEC, 2019b)
BSuoS and TNUOS costs	Network use of service charges	National Grid	Freely available	(National Grid, 2019a)
DUKES	Database of all transmission connected generation capacity in the UK	DESNZ	Freely available	(DESNZ, 2023d)

Appendix B: Technical data

Technical data used for the main model categories is given here where the data has been collated from different sources or calculated. Where referenced in the main thesis, data is taken from that database only.

B.1. Whole model technical data

Table B - 1: Data used to calculate the supply side cost for the final Net Zero model (BEIS, 2020b).

Thousand pounds	*CAPEX (low)*	*CAPEX (medium)*	*CAPEX (high)*	*OPEX*	*OPEX*
	£/MW	*£/MW*	*£/MW*	*£/MW*	*£/MWh*
CCGT with CCUS	1121.5	1326.1	1570	56.6	5
Hydrogen	627.3	628.1	629	40.6	2
Nuclear	3810	4351	5790	166.8	5
BECCS	2470.2	3190.5	4230.6	359.8	4
Hydro	820.1	2240.2	3660.2	113.4	9
Hydro pumped storage	1850	3460	3850	103	4
BESS	-	3760	-	78.2	7
Onshore wind	-	228.3	-	45	3.5
Offshore wind	942.7	1233.8	1414.7	62	6
Solar PV	1216	1824.3	2534.1	177.4	1
Tidal stream	211.3	251.4	411.5	16.6	0
CCGT with CCUS	1955.4	3440	4880	110.2	8

Table B - 2: Data used to calculate electrolysis costs for the final Net Zero model (BEIS, 2021a).

		High	Mean	Low
CAPEX	*£000/MW*	1299.07	586.66	334.95
OPEX	*£000/MW*	51.96	36.82	28.67
OPEX	*£/MWh*	14.1	4.8	2.1

Table B - 3: Data used to calculate hydrogen storage costs for the final model (DESNZ, 2023h)

		High	Medium	Low
Compressor CAPEX	*£000/MW*	1306.7	980	653.3
Compressor OPEX	*£/MWh*	30	23	15
Storage CAPEX	*£/MWh*	5348	4011	2674

B.2. Demand model technical data

Table B - 4: OSM categories mapped to the modelled BEES categories for non-domestic buildings.

OSM occupancy	*Mapped occupancy*	*OSM occupancy*	*Mapped occupancy*
school	school	bakery	small shop
guesthouse	residential	butcher	small shop
hotel	residential	library	school
chalet	residential	sports_centre	leisure centre
community_centre	club and community centre	theatre	theatre
airport	airport	furniture_shop	small shop
museum	Museum	courthouse	law court
post_office	small shop	car_dealership	showroom
hostel	hotel	veterinary	small shop
hospital	health centre	large non-food	large non-food
university	school	fish farm	fish far
supermarket	large food shop	college	school
caravan_site	residential	computer_shop	small shop
restaurant	restaurant	mall	large non-food
fire_station	fire/ambulance/police station	arts_centre	museum
ferry_terminal	ferry terminal	car_rental	office
town_hall	club and community centre	dentist	office
cafe	cafe	bicycle_shop	small shop
doctors	health centre	optician	small shop
gift_shop	small shop	pharmacy	small shop
wastewater_plant	water treatment	store	small shop
pub	pub	military storage	military storage
police	fire/ ambulance/ police station	sports_shop	small shop
bank	office	bookshop	small shop
public_building	office	jeweller	small shop

Table B - 5: Appliance data mapped to time use data actions and calibrated to match surveyed annual demand data (Intertek, 2012).

Appliance	*Demand (10 minutes) (Wh)*	*Number of 10-min periods*
Dishwasher	97.9	18
Dryer	444.5	5
Kettle	187.0	1
Microwave	312.3	1
Oven	461.8	5
Cooktop	333.0	3
Washing machine	63.9	12

Table B - 6: Bus data collected to allocate bus demand between the islands.

Island	Bus number	Number of laps			Dist. per lap	Total dist.	Reference
		Week-day	Satur-day	Sun-day			
Mainland of Orkney	6	7	7	3	25	1125	(Orkney Islands Council, 2023a)
	2	6	6	3	15	585	
	3	7	3	0	20	760	
	x1	30	20	10	25	4500	
	4	30	20	10	10	1800	
	7	3	3	0	70	1260	
	8s	1	1	0	70	420	
	9	11	11	4	20	1400	
Mainland of Shetland	4	23	25	7	20	2940	(ZetTrans, 2023)
	6	32	18	9	30	5610	
	8	2	2	0	40	480	
	9	10	10	11	30	2130	
	12	5	0	0	25	625	
	19	6	6	0	40	1440	
	21	6	6	0	60	2160	
	23	13	11	0	40	3040	
	24	2	2	0	150	1800	
	24y	8	7	0	40	1880	
	28	8	6	0	30	1380	
	29	7	7	0	20	840	
	30	9	6	0	30	1530	
Lewis and Harris	w1	5	4	0	40	1160	(Comhairle Nan Eilean Siar, 2023)
	w2	7	7	0	70	2940	
	w3	4	4	0	40	960	
	w4	9	4	0	60	2940	
	w5	17	17	0	15	1530	
	w6a	16	16	0	25	2400	
	w7	9	0	0	15	675	
	w8	9	5	0	30	1500	
	w9	7	7	0	50	2100	
	w10	7	7	0	50	2100	
	w11	3	2	0	50	850	

Island	Bus number	Number of laps Week-day	Satur-day	Sun-day	Dist. per lap	Total dist.	Reference
	w12	2	2	0	50	600	
	w13	9	2	0	30	1410	
Benbecula	w14	3	4	0	15	285	
	w16	8	5	0	40	1800	
	w17	9	6	0	40	2040	
	w18	8	7	0	90	4230	
	w19	5	2	0	20	540	
Barra	w32	5	5	0	20	600	
Skye	54	3	0	0	40	600	(Stagecoach, 2023)
	52	5	3	0	60	1680	
	55	9	0	0	35	1575	
	56	14	4	0	40	2960	
	57	11	7	0	80	4960	
	152	3	0	0	60	900	
	150	3	0	0	30	450	
	155	5	0	0	40	1000	
Islay	450	10	7	0	50	2850	(Argyll and Bute Council, 2023)
Jura	451	9	6	0	40	2040	
Mull	96	3	3	2	60	1200	
Arran	322	15	10	0	20	1700	(Visit Arran, 2023)
	323	15	10	0	20	1700	
	324	15	10	0	20	1700	

Table B - 7: Appliance efficiency improvements modelled for the given appliance efficiency ratings (BEIS, 2021b).

Appliance	*A*	*B*	*C*	*D*
Lighting	56%	37%	19%	0%
Refrigeration	49%	36%	20%	0%
Washing machine	35%	25%	14%	0%
Oven	58%	42%	23%	0%
Dishwasher	36%	24%	12%	0%

Table B - 8: Costs (£) to replace major appliances by energy efficiency rating sampled from a cost comparison website (TurnRound, 2023).

Appliance	*A*	*C*	*D*
Washing machine	355	289	259
Dryer	389	269	229
Fridge	600	500	350
Oven	370	250	200
Dishwasher	985	688	549
Total	2699	1996	1587

Table B - 9: Assumed lifetime of energy efficiency measures used for cost-effectiveness calculations. (Hoffman *et al.*, 2015).

Aspect	*Lifetime*
Appliance efficiency	8
Standby power	8
DSR/ P2P trading	15
New building and retrofitting	15
Heating electrification	15
Transport demand	15
Industrial demand efficiency improvements	15

B.3. Biowaste model technical data and calculations

Table B - 10: Summary of the total biomass production, waste fraction and energy potential for the Scottish islands. References are provided below.

Sector	*Resource Type*	*Production (kT)*	*Waste Conversion Factor*	*Waste (kT)*	*Biogas Yield (GWh/kT)*	*Energy Potential (GWh)*
Food waste	Domestic	-	-	11.5 [AB]	1.1 [C]	12.7
	Non-domestic	-	-	5.4 [BD]	1.1 [C]	5.9
Farm Fallen Stock	Cows	75.8 [E]	0.004 [F]	0.3	1.66 [G]	0.5
	Sheep	45.2 [E]	0.065 [F]	2.9	1.66 [G]	4.9
Fish Farm Mortalities	Atlantic Salmon (Demersal)	-	-	17.1 [H]	1.5 [C]	25.7
Distilling	Draff	37.2 [I]	2.5 [J]	93.0	1.1 [C]	102.3
Distilling	Spent Lees	37.2 [I]	1.4 [J]	52.1	0.003 [C]	0.2
	Pot Ale	37.2 [I]	7.9 [J]	293.9	0.1 [C]	29.4
Brewing	Grain (solid)	0.4 [DK]	0.2 [L]	0.0800	1.51	0.1208
	Hops	0.4 [DK]	0.002 [L]	0.0008	0.84	0.0007
	Yeast	0.4 [DK]	0.015 [L]	0.0060	0.01	0.0001
Seafood Processing	Pelagic	39.4 [HM]	9.9 [N]	390.5	0.0241	9.5
	Demersal	6.4 [HM]	9.9 [N]	64.2	0.0241	1.6
	Shellfish	0.6 [HM]	9.9 [N]	6.0	0.0241	0.1
Meat Processing	Cows	13.2 [EO]	0.067 [EO]	0.9	0.0315	0.0279
Dairy Processing	Dairy	44.3 [EO]	0.029 [BE]	1.3	0.0345	0.0455
					TOTAL	192.9

A: (National Records of Scotland, 2016)
B: (WRAP, 2020)
C: (Ricardo Energy and Environment, 2019)
D: (OpenStreetMap contributors, 2021)
E: (EDINA, 2021)
F: (Alba *et al.*, 2015)
G: (Williams, Jones and Edwards-Jones, 2008)
H: (Scotland's Aquaculture, 2021)
I: (Gray, 2020)
J: (White *et al.*, 2016)
K: (Brew Plants, 2021)
L: (Zero Waste Scotland, 2017)
M: (Marine Management Organisation, 2016)
N: (Chowdhury, Viraraghavan and Srinivasan, 2009)
O: (DEFRA, 2022b)

Table B - 11: Calculation of the waste proportion for dairy and meat processing. References are provided throughout the table.

Ref	Name	Year	Value		Units	Calculation
			Dairy	Meat		
A	UK waste water (WRAP, 2020)	2015	423	370	kT	-
		2018	429	422		
B	UK production (DEFRA, 2022a)	2015	14,882	5,739	kT	-
		2018	14,874	6,121		
C	Mean proportion of waste	-	0.029	0.067	kg / kg production	C = A x B

Table B - 12: Calculation of the production for breweries from floor space factors. References are provided throughout the table.

Ref	Name	Value	Units	Calculation
A	Production factor per cycle	10 (Brew Plants, 2021)	HL/m^2	-
B	Number of cycles per year	20 (Brew Plants, 2021)	-	-
C	Production per year	200	HL/year/m^2	C = A x B

Table B - 13: Types of OSM road types from OSMnx and assumed travel speeds.

OSM road type	Count	Suitable for vehicles	Speed (km/h)
Primary	11757	TRUE	80
Track	23460	TRUE	20
Residential	13823	TRUE	30
Service	52825	TRUE	50
unclassified	21479	TRUE	50
Tertiary	7866	TRUE	50
Footway	10120	FALSE	-
Path	8067	TRUE	30
Steps	498	FALSE	-
Secondary	7426	TRUE	51
Pedestrian	124	TRUE	5
primary_link	21	TRUE	60
living_street	2	TRUE	10
secondary_link	2	TRUE	40
Corridor	2	FALSE	-
Trunk	572	TRUE	40
trunk_link	1	TRUE	40
cycleway	114	FALSE	-
bridleway	14	FALSE	-
Road	2	TRUE	80

Table B - 14: Description of non-domestic food waste floor space factors. References are provided throughout the table.

	National			Scottish Islands	
	Annual waste (tonnes/year) (WRAP, 2020)	Floor area (m2) (BEIS, 2016a)	Waste factor (tonnes/m2/year)	Floor area (m2) (OpenStreetMap contributors, 2021)	Annual waste (tonnes/year)
Restaurant/ café	4.59	128	0.0358	214	7.66
Supermarket	13.70 (Tesco, 2017)	1,053	0.0130	1,076	13.99
Pub	5.09	350	0.0145	205	2.97
Hotel	6.38	387	0.0175	454	7.95

Table B - 15: Calculation of the energy content of fish processing and brewery waste. Brewery references (identical for grain, hops and yeast) are shown for grain only. References are provided below.

	Name	*Values*				*Units*	*Calc.*
	Industry	Fish processing [A]	Brewery				
	Resource	Wastewater	Grain	Hops	Yeast		
A	Wastewater per unit production	9.9	0.2 [B]	0.00176	0.015	litres/kg	-
B	Chemical oxygen demand (COD) per unit wastewater	0.005	0.33 [C]	0.37	0.032	kg COD/L	-
C	Methane per unit COD	0.35	0.5 [C]	0.25	0.04	kg CH4 / kg COD	-
D	Methane production per unit waste	0.00175	0.1084	0.0608	0.0008	kg CH4 / L	B x C
E	Energy content of methane [C]	0.0139	0.0139	0.0139	0.0139	MWh/kg CH_4	
F	Energy potential per unit production	0.0241	1.51	0.84	0.01	MWh/tonne	A x D x E x 1000

A: (Chowdhury, Viraraghavan and Srinivasan, 2009)
B: (Shaiith, 2015)
C: (Gunes *et al.*, 2019)

Table B - 16: Calculation of the energy content of meat and dairy processing wastewater. References are provided below.

	Name	*Values*		*Units*	*Calculation*
	Industry	Meat processing [A]	Dairy processing [B]		
	Resource	Wastewater	Wastewater		
A	Wastewater per unit production	0.067	0.029	litres/kg	-
B	Volatile solids (VS) per unit wastewater	0.07	0.01103	kg VS/L	-
C	Methane per unit VS	0.049	-	m^3 CH4 / kg VS	-
D	Methane density	0.657	-	kg/m^3	-
E	Methane per unit VS	-	0.22535	kg CH4 / kg VS	-
F	Methane per unit wastewater	0.0023	0.002486	kg CH_4 / L	B x C x D (meat); B x E (dairy)
G	Energy content of methane (Gunes *et al.*, 2019)	0.0139	0.0139	MWh/kg CH_4	-
H	Energy potential per unit production	0.0315	0.0345	MWh/tonne	F x G x 1000

A: (Hamawand, 2015)
B: (Shi *et al.*, 2021)

B.4. Supply model technical data

Table B - 17: Renewable generation techno-economic characteristics used in the model, with the source given in the first column unless otherwise noted in each cell.

	Units	*Onshore Wind*	*Offshore Wind*	*Solar PV*	*Hydro*	*Wave*	*Tidal Stream*
VO&M Cost [1]	£/MWh	5	4	-	6	24	7
Maintenance Rate [2]	%	3	3	1	3	7.5 [3]	7.5 [3]
Forced Outage Rate [2]	%	2	2	1	3	7.5 [3]	7.5 [3]
Mean Time to Repair [2]	h	72	72	48	90	72 [3]	72 [3]

[1] (BEIS, 2016b); [2] (Diuana, Viviescas and Schaeffer, 2019); [3] (UKERC, 2014).

Table B - 18: Thermal generation techno-economic characteristics used in the model, with the source given in the first column unless otherwise noted in each cell. Heat rates and start costs are given in bands of cold/ warm/ hot for times of 8/72/150 hours. Note that hydrogen is not modelled in the validation year but is included in the Net Zero model for 2045 (Section 7).

	Units	Generator					
		CCGT	Coal	OCGT	Nuclear	Biomass	Hydro-gen
Min. Stable Factor [1]	%	20	30	15	45 [2]	50	20
Heat Rate [1]	GJ/MWh	6.5/ 7.5/ 8.2	8.3/ 9.3/ 10.8	11.7	11	13.8	6.0
VO&M Cost [3]	£/MWh	3	3.8	3	5	8	2
Min. Downtime [1]	h	2	4	2	12	4	4
Start Costs [4]	£/MW	23/ 33/ 48	29/ 42/ 75	11/ 14/ 20	33/ 39/ 64	33/ 39/ 64	96
Maintenance Rate [2]	%	5	8	3	Varied [5]	2	5
Forced Outage Rate [2]	%	5	8	2	2 [5]	2	5
Mean Time to Repair [2]	h	64	64	64	54 [5]	64	64
Emissions [2]	Kg/MWh	499	888	616	-	-	-
Fuel Price	£/GJ	Daily [6]	Quarterly [7]	Daily [8]	1.2 [3]	Annual [8]	Section 3.4.1

[1] (Gonzalez-Salazar, Kirsten and Prchlik, 2018); [2] (DIW Berlin, 2013); [3] (BEIS, 2016b); [4] (National Renewable Energy Laboratory, 2012); [5] (International Atomic Energy Agency, 2019); [7] (Energy Solutions, 2020); [8] (BEIS, 2019b); [9] (E4tech, 2016).

Table B - 19: Technical characteristics of DSR, heat, and electrolysis used in the final model only.

Aspect	*Name*	*Value*	*Units*	*Ref*	*Note*
DSR	Time load deferred by	4	Hours	(BEIS, 2022a)	See Section 6.4.3.
Heat	Boiler efficiency	85	%	(EMEC, 2019a)	
Electrolysis	Efficiency	82	%	(BEIS, 2021a)	Average value for three technologies

Table B - 20: Electrolysis cost data (BEIS, 2021a).

Variable	*Value*	*Units*
Efficiency	81.5	%
Lifetime	30	Years
CAPEX	545.4	£/kW
OPEX- fixed	30.8	£/kW/year
OPEX- variable	0.00345	£/kWh
Cost of capital	10%	-