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Modelling the energy transition on the Western Isles, Scotland

Scenario analysis to compare future pathways on the island of Lewis and Harris

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Abstract

Renewable energy potential at a local level is important if communities are to play a role in the wider global energy transition. The following thesis studies the ongoing transition on the island of Lewis and Harris, part of the Western Isles, Scotland. A PLEXOS energy model is constructed, focusing on the island's electricity system. Future local renewable potential is investigated through several scenarios. Electrification of heating and transportation sectors is assumed, via high uptake of heat pumps and electric vehicles, as the replacement of the failed subsea mainland interconnection and the future of the island's diesel power station are explored. Battery energy storage systems provide a potential solution to the decommissioning of the diesel power station, coupled with additional solar photovoltaics to complement already installed wind resources. The importance of interconnection capacity is highlighted if the island is to become a major exporter of wind power, although through sensitivity analysis it was found that the economic viability of new wind turbines is uncertain due to falling mainland electricity prices. The representation of the mainland is identified as a key limitation within the study, in particular the projection of future electricity prices and their potential temporal relationship with local wind production. Greater consideration here would be beneficial. Expansion of the modelling to include heating demands at a wider level, alongside potential hydrogen production, could be interesting areas to explore further.

Sammanfattning

Förnybar potential på lokal nivå är viktig om energisamfund ska kunna spela en roll i den bredare globala energiövergången. I denna avhandling undersöks den pågående energiövergången på ön Lewis och Harris, som är en del av de Yttre Hebriderna (eng. Western Isles) i Skottland. En PLEXOS-energimodell konstrueras med fokus på öns elsystem och den framtida lokala potentialen för förnybar energi undersöks genom flera scenarier. Elektrifiering inom uppvärmnings- och transportsektorn uppskattas, genom en stor ökning av värmepumpar och elfordon, för att undersöka en ersättningsmöjlighet till den misslyckade undervattenskabeln till fasta Skottland och framtiden för öns dieselkraftverk utvärderas. Batterilager är en möjlig lösning för avveckling av dieselkraftverket, tillsammans med ytterligare solceller för att komplettera den redan installerade vindkraften. Vikten av överföringsmöjligheter till fastlandet betonas om ön skulle komma att bli en stor exportör av vindkraft, även om det genom känslighetsanalysen konstateras att den ekonomiska bärkraften hos nya vindturbiner är osäker på grund av sjunkande elpriser på fastlandet. Representationen av fastlandet har identifierats som en nyckelbegränsning i studien, särskilt prognosen för framtida elpriser och dess potentiella samband med lokal vindkraftsproduktion. Detta är ett område som skulle kunna vidareutvecklas. Att utvidga modelleringen till att omfatta uppvärmning på en bredare nivå, tillsammans med eventuell vätgasproduktion, skulle kunna vara intressanta områden att utforska ytterligare.

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List of Abbreviations and Symbols

ADMD	**A**fter **D**iversity **M**aximum **D**emand
BEIS	**B**usiness, **E**nergy, and **I**ndustrial **S**trategy
BESS	**B**attery **E**nergy **S**torage **S**ystems
BST	**B**ritish **S**ummer **T**ime
CAPEX	**Cap**ital **Ex**penditure
CO_2	**C**arbon **D**ioxide
CO_2eq	**C**arbon **D**ioxide **eq**uivalent
COP	**C**oefficient **o**f **P**erformance
CfD	**C**ontracts **f**or **D**ifference
CWF	**C**ommunity **W**ind **F**arm
DSO	**D**istribution **S**ystem **O**perator
EPC	**E**nergy **P**erformance **C**ertificate
ETS	**E**mission **T**rading **S**cheme
EU	**E**uropean **U**nion
EV	**E**lectric **V**ehicle
GHG	**G**reenhouse **G**as
GMT	**G**reenwich **M**ean **T**ime
GJ	**G**iga**j**oule
GWh	**G**igawatt **h**ours
HP	**H**eat **P**ump
HV	**H**igh-**V**oltage
HVDC	**H**igh-**V**oltage, **D**irect **C**urrent
IEA	**I**nternational **E**nergy **A**gency
kW	**k**ilo**w**att
kV	**k**ilo**v**olt
kWh	**k**ilo**w**att **h**our
LDC	**L**oad **D**uration **C**urve
LULUCF	**L**and **U**se, **L**and **U**se **C**hange and **F**orestry
LTDS	**L**ong **T**erm **D**evelopment **S**tatement
MIP	**M**ixed **I**nteger **P**rogramming
M.Sc.	**M**aster of **Sc**ience
Mt	**M**ega **t**onne
MW	**M**ega**w**att
MWh	**M**ega**w**att **h**our
NPV	**N**et **P**resent **V**alue
O&M	**O**perating and **M**aintenance
OFGEM	**Off**ice for **G**as and **E**lectricity **M**arkets
OPEX	**Op**erating **Ex**penditure
PPA	**P**ower **P**urchase **A**greement
PSS	**P**rimary **Sub**station
PV	**P**hoto**v**oltaics
RES	**R**enewable **E**nergy **S**ource
RIIO	**R**evenue = Incentives + **I**nnovation + **O**utputs
SDG	**S**ustainable **D**evelopment **G**oal
SSEN	**S**cottish & **S**outhern **E**lectricity **N**etworks
SHET	**S**cottish **H**ydro **E**lectric **T**ransmission
TSO	**T**ransmission **S**ystem **O**perator
UK	**U**nited **K**ingdom
UN	**U**nited **N**ations
V0G	Electric **V**ehicle, direct charging
V1G	Electric **V**ehicle, smart charging
V2G	**V**ehicle-to-**G**rid
VRES	**V**ariable **R**enewable **E**nergy **S**ources
WACC	**W**eighted **A**verage **C**ost of **C**apital

1 Introduction

The following thesis was completed at KTH Royal Institute of Technology, Stockholm, as the final part of a Master of Science, M.Sc., degree in Innovative Sustainable Energy Engineering. The course is run by the Nordic Five Tech alliance and the work was also completed with Aalto University, Finland.

The world is currently faced with a climate emergency, as global warming threatens to change life on earth and land as we currently know it. Greenhouse gas (GHG) emissions are a major contributor to global warming and as such, a move away from fossil fuel sources towards low carbon alternatives is needed if the world is to try and limit the ecological damage being done. (Scientific American, 2021)

A major part of this energy transition is the required build out of renewable energy sources (RES), to provide sustainable power for the world's future energy systems. The United Nations (UN) outlines 17 Sustainable Development Goals (SDGs); described as "a call for action by all countries – to promote prosperity while protecting the planet". SDG 7 focuses on ensuring access to affordable, reliable, sustainable, and modern energy. It is important that local communities can play their part in the global energy transition and are allowed the opportunity to benefit from the widescale changes that are occurring.

The following work focuses on the Western Isles, Scotland, with the aim of better understanding the ongoing energy transition that is occurring on the island, utilising energy modelling as an analysis tool. Islands often represent areas that have historically relied on imports for most of their energy demands. The energy transition represents an opportunity for such areas to become more self-sufficient, as well as potential exporters of clean energy.

The project was undertaken during the end of 2020 and up until the summer of 2021. During this period, the world was faced with the Covid-19 pandemic. The full extent of the impacts of the pandemic are still largely unknown and as such the thesis does not attempt to include all the changes that may occur.

The thesis is broken down into the following sections. Section 2 includes a background to Scotland and the UK, before focusing on the current situation of the Western Isles in terms of the energy, and in particular the electricity, sector. The island is faced with key decisions, both in the present and near future, which are also discussed in the section. A literature review that was conducted to provide further background information is then summarised before the research objective is defined. Sections 3 and 4 describe the methodology for both the creation of an energy model to represent the area, and the future scenarios that are analysed in the study. The results of the scenarios are detailed in section 5, along with study limitations and possible future work. Finally, the work is concluded in section 6, with a bibliography and any annexed work completing the report.

2 Background

2.1 Scotland and the UK's Climate Change Goals

Scotland has GHG emission reduction targets of net-zero by 2045 at the latest, via the 2019 CC Act. (Scottish Government, Riaghaltas na h-Alba) The act includes interim targets of 75% by 2030 and 90% by 2040, compared to 1990 levels of 76.3Mega-tonnes (Mt) of Carbon Dioxide equivalent (CO_2eq) and aims to achieve net-zero 5 years earlier than the wider UK target of 2050. Net-zero GHG implies complete elimination of fossil fuel consumption, a pathway that will bring new challenges as the transition towards low carbon alternatives accelerates. (Committee on Climate Change, 2019)

From 1990 to 2018 the estimated emissions have fallen 45.4%, with the main contributions coming from: reduction in electricity generation emissions; Land Use, Land Use Change and Forestry (LULUCF); a reduction in waste management; and a fall in business emissions. (Scottish Energy Statistics, 2020)

It is estimated that almost 89% of the remaining emissions are associated with energy, of which the majority come from the heat, transport, and electricity sectors. This highlights the need for further decarbonisation within the energy sector, as well as finding low carbon, fossil fuel alternatives within the heat and transport sector. (Statistics, Scottish Energy, 2020b)

The importance of a whole systems approach has been highlighted by the United Kingdom (UK) Government in recent years, where all sectors are incorporated within a holistic view and an emphasis placed on understanding interactions between different parts of the whole energy system. (Council for Science and Technology,)

The timing of the thesis comes soon after the period in which Britain officially left the European Union (EU), following the Brexit referendum in 2016 and then a transition period from 31st January 2020 - 31st January 2021. Whilst the aims of this thesis are not to directly investigate the impacts of Brexit, it is acknowledged that the energy sector in both the EU and the UK will likely be affected.

Scotland is divided into 32 local council areas. This M.Sc. thesis will concentrate on the Western Isles, pictured below in Figure 1. Due to time constraints and the configuration of the electricity system on the island, the work carried out focused on the northernmost section of the Western Isles: Lewis & Harris. The region has access to some of the greatest onshore wind potential in Europe, as well as considerable solar irradiation potential, relative to the rest of Scotland. (DTU, 2021) (Department for BEIS, 2021) Despite this, the island experiences some of the highest energy prices in the UK and its inhabitants face the highest levels of Fuel Poverty of any local authority in Scotland. (UK Power, 2021) (Scottish Government, 2019) There is a drive to meet on island demand with locally owned resources and in recent years the region has seen numerous renewable energy projects realised, many of which were led by local community groups who are active in the island's energy ecosystem. As an island, the region faces additional challenges such as limited connection to the National Grid: an issue that has become extremely present due to the current failure of the subsea cable that joins Lewis and Harris to the mainland. As Scotland continues towards its net-zero targets the region may face both new challenges to the energy system as well as possible opportunities for greater local RES.

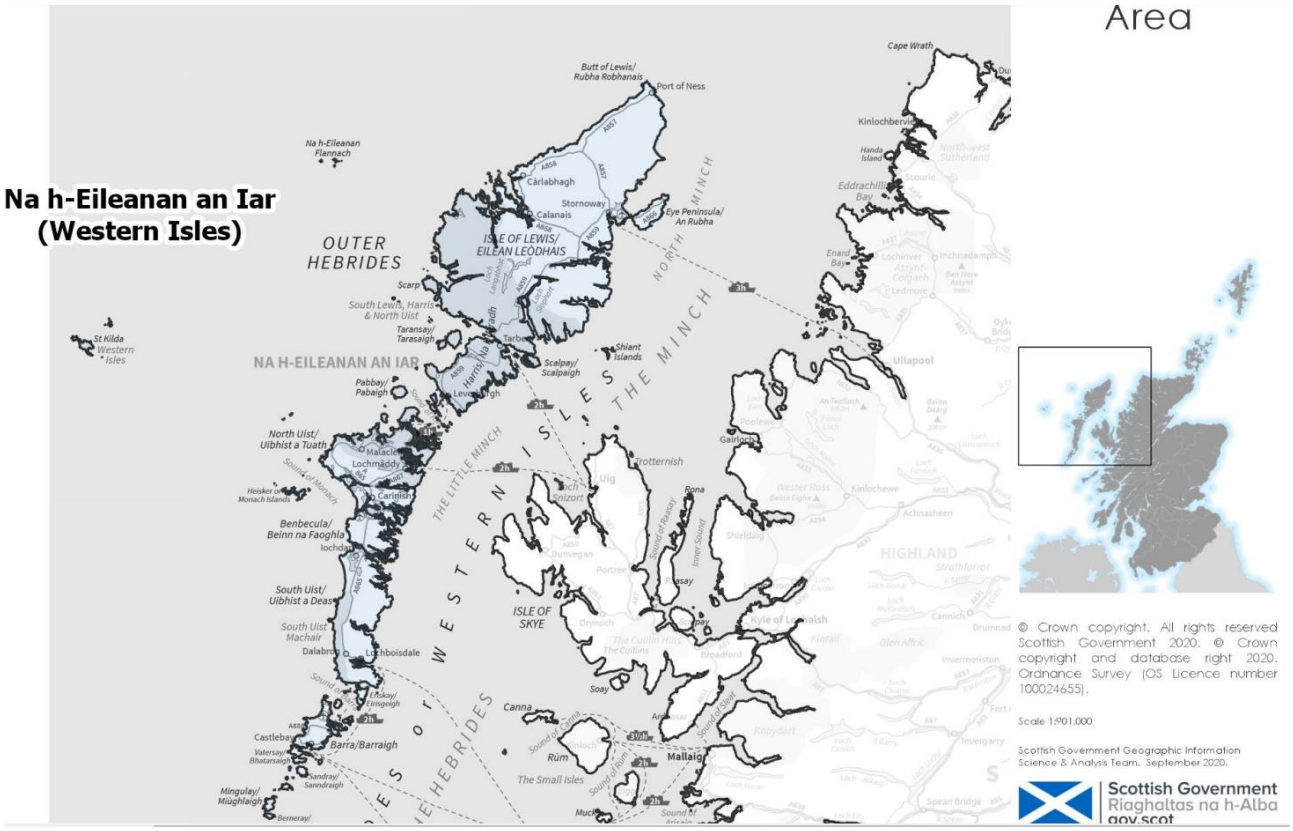

Figure 1 Image of local authority area Na-h Eileanan an Iar (Western Isles) (GOV.Scot, 2020a)

2.2 Western Isles Background

The Western Isles are a chain of islands off the west coast of Scotland, stretching 209km from North to South. The area is historically Gaelic speaking, with over 52% of the population still speaking the language according to the 2011 census. The area is part of the wider Hebrides archipelago, with the Western Isles referred to interchangeably as the Outer Hebrides. The Gaelic name for the islands is *Na h-Eileanan an Iar*. For clarity and simplicity, the Western Isles will be used within this report.

The Western Isles includes the major islands of Lewis and Harris, North Uist, Benbecula, South Uist and Barra, as well as 11 further inhabited islands. Lewis and Harris, despite the name, is one landmass with an area of 2,179 km^2 making it the 3rd largest island in the British Isles, after Great Britain and Ireland.

The last census, 2011, indicated a population of 27,684 across the whole of the Western Isles, with 21,031 living on Lewis and Harris itself. The largest settlement on the islands is Stornoway, on Lewis.

2.3 Western Isles Energy Transition

To give further background to the energy system on the Western Isles, current statistics available for the whole Local Authority area have been collated and are presented within this section. The data in 2.3.1 is taken directly from the Department for Business, Energy, and Industrial Strategy (BEIS). (Department for BEIS, 2020) (Department for BEIS, 2020a)

2.3.1 Demographics and Energy Sector Overview

The area faces the challenge of an aging population and net migration which has led to projections for falling population in the coming decades. This changes between areas on the island, e.g., Stornoway, the main urban centre, remains relatively unchanged whilst more remote sections of the island may experience population dropping between 4-7% in the coming decades. (National Statistics, 2020)

The primary energy mix, in gigawatt hours (GWh), from 2014 is shown below, in Figure 2. All energy is imported apart from any electricity that is generated locally. The electricity mix from 2014 also shown below in Figure 2 and explained further in section 2.3.2. From the primary energy mix, there is a clear reliance on imported fossil fuels. This can leave the area subject to higher fuel costs than the mainland due to additional transportation costs and constraints. By fuel shifting from fossil fuel products to electricity, where possible, there may be further opportunity to meet energy demand with local RES.

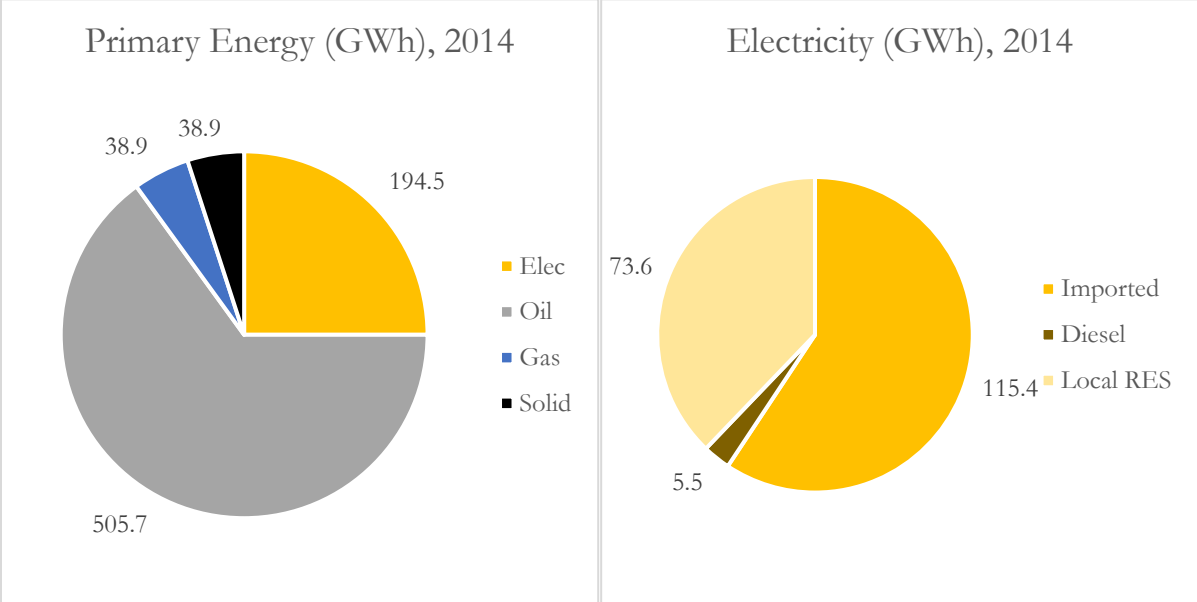

Figure 2 (left) Primary Energy (GWh), 2014, (right) Electricity mix (GWh), 2014.

The Western Isles final energy consumption, from 2018, is displayed by sector in Figure 3. Across all sectors petroleum products dominate, with electricity playing major roles in domestic, and industrial and commercial, consumption. It should be noted that marine and aviation sectors are excluded from the BEIS statistics due energy and emission accounting processes.

2018 Carbon Dioxide (CO_2) emissions from each of the sectors are displayed in Figure 4 (Department for BEIS, 2020). Domestic emissions account for over 38% of the total, with transportation emissions exceeding those of industry and commercial. It is noticeable that emissions from electricity are far from negligible. This is down to the carbon intensity of the mainland grid and emissions from the diesel generators on the island that supply electricity during peak demand as well as during periods of maintenance for the subsea mainland cable connection.

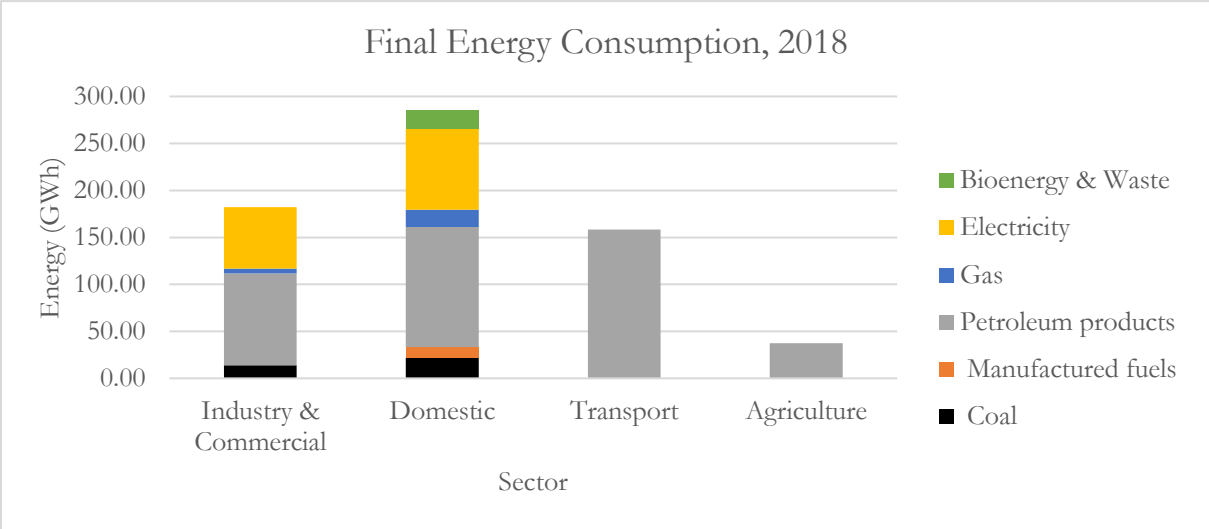

Figure 3 Final Energy Consumption by Sector on the Western Isles, 2018

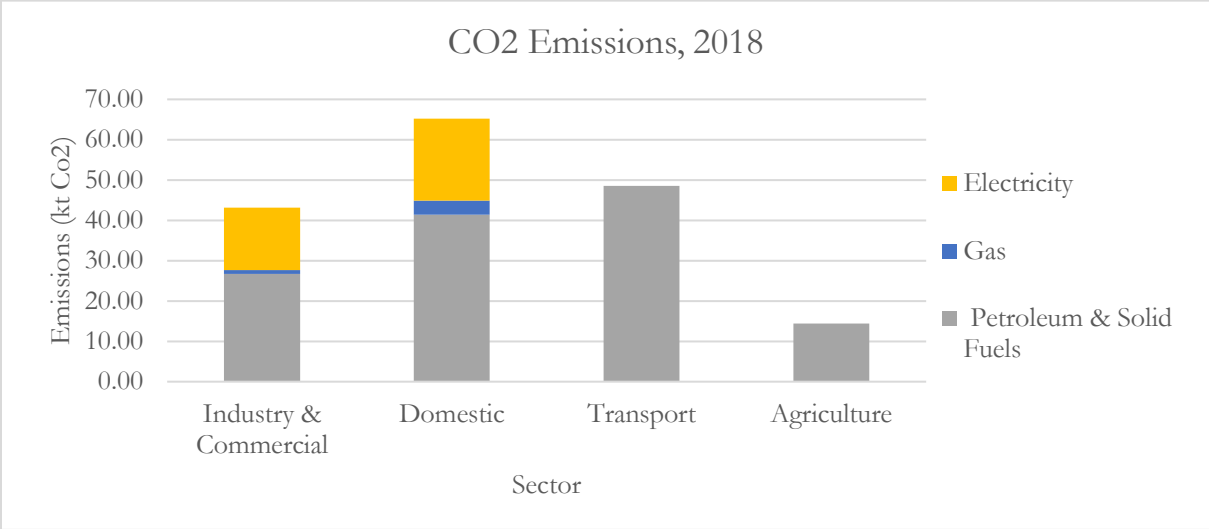

Figure 4 CO_2 Emissions by Sector on the Western Isles, 2018

The main final energy sources, summarised from a 2014 energy audit of the island: (Element Energy, 2014)

- **Electricity**. Used for both domestic and industrial purposes. Further detail in section 2.3.2.
- **Gas.** Used for domestic and public sector heating. Liquid Petroleum Gas is used in the Stornoway gas network, circa 1700 customers, as well as by individuals using bottled gas. Gas is imported to the islands by boat, mainly via Stornoway.
- **Diesel (Gas Oil).** Used as fuel for diesel generators, fishing vessels and ferries, boilers, and a small portion of domestic heating. All petroleum products are imported.
- **Kerosene.** Used mainly for domestic heating, all imported.
- **Diesel (Vehicles).** Used for transportation fuel, all imported.
- **Unleaded petrol.** Used for personal transportation, all imported.
- **Coal.** Used for domestic heating, all imported.
- **Wood.** Sourced locally and used, marginally, for domestic heating.
- **Peat.** Soured locally and used, marginally, for domestic heating.

2.3.2 Electricity Sector Overview

The electricity on the island is supplied either by on-island sources, or via the two subsea cable connections with the mainland. The subsea cable also allows for electricity to be exported from the island and retailed on the Scottish mainland.

Table 1 displays 2019 total installed generation capacity for the region, in megawatts (MW), as well as generation figures for the whole of the Western Isles and annual estimated production from the diesel stations, in GWh. (Element Energy, 2014) (Department for BEIS, 2020a)

Table 1 Western Isles on island electricity generation, 2019

	Installed Capacity (MW)	Electricity (GWh)
Onshore wind	44.3	136.2
Solar photovoltaics (PV)	1.2	1.2
Hydro	2.3	6.8
Anaerobic Digestion	0.2	0.4
Diesel Power Stations	49.7	5
Imported Electricity[1]	-	54.4
Exported Electricity[2]	-	48.2

The table highlights that there is already a large amount of wind resources on the island, in comparison to the total current electricity demand. Most of the solar and wind projects were supported via the Renewable Obligation and Feed-in-Tariff support-scheme mechanisms used by the government to support renewable projects in the UK. The projects offer opportunities to the local communities to benefit from the local production.

These support mechanisms, however, have ended and been replaced by the extremely competitive Contracts-for-Difference, CfD, scheme. New projects that do not gain the CfD support must be either be competitive on the electricity market without subsidies or find alternative routes to market. This has a knock-on effect to local communities, as locally owned community generation provides key income to the island, which is used to fund local innovative projects aimed at tackling Fuel Poverty, as well as housing, environmental and economic schemes. (CNE-Siar, 2017)

With the possible electrification of key sectors, there may also be possibilities for local RES to meet this additional demand.

The electricity sector is made up of several different parties, detailed below.

Scottish Hydro Electric Transmission plc (SHET)

SHEN operate as the Transmission System Operator (TSO) in Scotland. Their UK equivalence is the NG. They own and maintain networks of 132kilovolt (kV) and above. With relevance to the Western Isles, the connection between Harris and Stornoway is a SHET cable and thus comes under the TSO remit. Any additional interconnection between the island and the mainland would also be considered transmission if it were to be 132kV or above.

Scottish and Southern Electricity Networks (SSEN)

SSEN are the Distribution System Operator (DSO) in Scotland. SSE own and maintain the networks between the high-voltage (HV) transmission system and the customers on the island. They are also one of the leading generators of electricity in the UK. On the Western Isles they own the diesel and hydro power stations. In recent years, the role of the distribution operators has changed in name from distribution network operator to DSO. This move is aimed at pushing the transition to a more modern, decentralised,

[1] Estimates based on confidential data provided by SSEN for Lewis & Harris.
[2] As above.

and flexible system which will help manage the challenges such as increased variable renewable energy sources (VRES), electric vehicles (EVs), and heat pumps (HPs) on the grid as well as enabling greater load shifting via initiatives such as demand side response and energy storage. (SSEN, 2018)

Office for Gas and Electricity Markets (OFGEM)

OFGEM are an independent National Regulatory Authority for both gas and electricity across the whole of the UK. They regulate distribution and transmission networks. Regulatory bodies play an important role in today's energy systems due to the natural monopoly that arise from energy transmission and distribution networks. OFGEM uses price controls as a method to regulate the DSOs, which are linked to the amount of investment that OFGEM thinks they are required to make. This can have an impact on the size and timing of investment decisions. Ultimately, large investments in the distribution and transmission networks must be given the green light by OFGEM.

OFGEM has three price controls under its RIIO (Revenue = Incentives + Innovation + Outputs) initiatives. Of most relevance here are the RIIO Electricity Distribution network price controls, RIIO ED1 and RIIO ED2. RIIO ED1 is currently in place and runs from 2015-2023. RIIO ED2 begins in 2023 and will run until 2028. These pricing control periods are of relevance for the Western Isles in relation to the possible investment of any new mainland distribution connection, as well as general upgrades to the distribution network.

2.3.3 Fuel Poverty and Policy Goals

Fuel poverty in Scotland is defined as households requiring "after housing costs have been deducted, more than 10% (20% for extreme fuel poverty) of their net income… to pay for their reasonable fuel needs" by Fuel Poverty (Targets, Definition and Strategy) (Scotland) Act 2019. (GOV.UK, 2019)

In 2018 the Scottish House Condition Survey found that dwellings on the Western Isles experienced the highest rate of both Fuel Poverty, 36%, and Extreme Fuel Poverty, 23%, compared to Scottish averages of 25% and 12%, respectively. (Scottish Government, 2019) The explanation behind these findings is complex and includes the impacts of high electricity tariffs, lower incomes, and long heating season within the area.

Whilst delivering the net-zero targets, Scotland is committed to a *Just Transition* that it is fair for all, thus delivering a low carbon economy that "improves the opportunities, life chances and wellbeing of every citizen" in the country. (GOV.Scot, 2020)

The UN outlines 17 SDGs, recognising the urgent need for ending poverty and inequality globally whilst simultaneously tackling climate change and protecting our natural habitat. Dealing with the fuel poverty experienced on the Western Isles aligns with the targets for SDG 7 – 'Ensuring access to affordable, reliable, sustainable, and modern energy for all'. This highlights the importance of delivering an energy system that is fit for the future and able to provide affordable and clean energy to the inhabitants on the Western Isles.

In 2019 the Outline Outer Hebrides Energy Strategy 2020-2030 was published by the Western Isles Local Authority. The report highlighted several key areas within their vision:

1. By 2030 the island would be a key contributor to national net-zero targets. An additional 500MW of commercial onshore wind generation would be built by 2030, complemented by 50MW of community owned generation.
2. Currently, all electricity generated on the island is exported to the grid before being bought back at a premium. Considering the previously mentioned fuel poverty on the island, tackling this situation is of the upmost importance.
3. On island hydrogen production was identified as a key growth area, to open alternative routes to market for community generators.

In addition, the Local Authority has joined with not-for-profit energy supplier Our Power to launch an alternative electricity tariff, to ultimately help on-island demand be met by local energy supply. (CNE-Siar, 2020)

This additional generation, point 1 above, would far outweigh the current installed capacity in the region. These additional projects are to be funded via the latest CfD rounds and thus would be built with meeting mainland demand, and therefore major exports, in mind. Due to this, their realisation is tied to the addition of a new high voltage direct current (HVDC) interconnector, with a capacity of 450-600MW, between Stornoway and the Scottish mainland which would carry the electricity to the UK via the national transmission grid. The possible connection has been spoken about for over 15 years and the current situation is that plans for the HVDC cable were rejected in 2019 by OFGEM. These are being revisited; however, it is far from certain and has created a 'chicken-and-egg' scenario where both the HVDC cable and additional wind projects wait for one-and-other to be given the green light. In the meantime, the current cable has failed. Due to this uncertainty the HVDC link it has not been included in this thesis. This is not a comment on the viability of the cable, in fact its potential importance is discussed in sections 5.4, as well as the conclusion.

2.3.4 Mainland Connection and Diesel Power Station

Figure 5 displays the distribution grid connections between the Ardmore (Isle of Skye) and the Western Isles. The connection at Ardmore links the system back to the Scottish mainland. For simplicity, the Isle

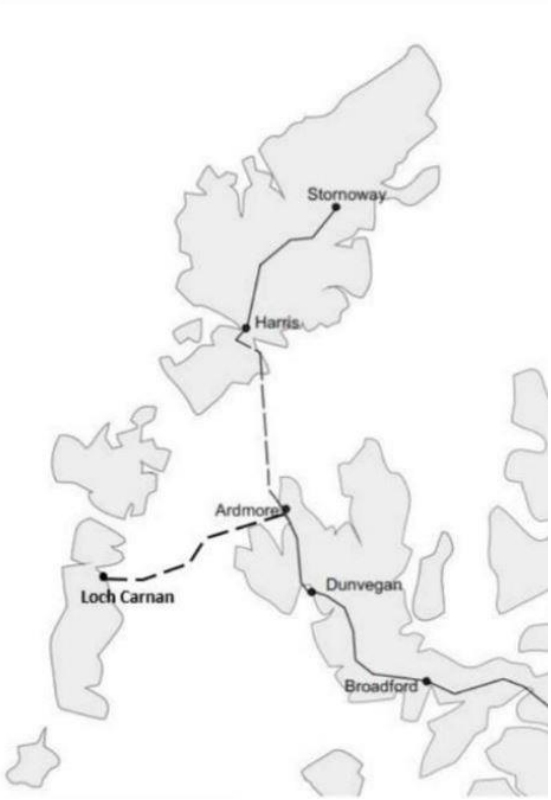

Figure 5 Mainland connections between Scottish mainland and Western Isles

of Skye will be referred to as part of the Scottish mainland during the thesis, despite being connected by a bridge and not land. Skye is served by the 132kV Scottish HV transmission network, with only a minor cable crossing.

The current subsea cable between Ardmore and Harris has failed as of October 2020. This has left the island disconnected from the mainland transmission grid and therefore reliant on the old diesel power station at Stornoway, with wind generator sites limited to 100kilowatts (kW) of output each. The local distribution operator plans to replace the failed interconnector with a new 30MW rated cable, by end of

August 2021. Even with the previous working subsea cable the island's electricity grid was often constrained, placing limits on the renewable community generators (wind) in terms of their allowed production which in turn hindered future renewable projects due to the lack of access to the grid. (SSEN, 2020)

The mainland connection serves the island for most of the year, apart from annual periods in the summer when the cable undergoes maintenance for approximately 3 weeks (2 in summer and 1 in autumn). During these periods, the diesel power station is used to meet the demand on the island. The power station has also been required historically during the period of high electricity demand in the winter months.

2.3.5 Net-zero Impacts

To achieve net-zero, fossil fuels for domestic and commercial heating consumption need to be replaced with low carbon heating solutions. One such option is to replace oil, coal, and gas heated boilers with heat pumps (HPs), coupled with a decarbonised electricity generation system. HPs are likely to be the main heating source in the UK due to their high efficiency (Maclean, et al., 2015) (Johnston, et al., 2005). The government has attempted to increase the uptake of HPs via funding sources such as the renewable heating incentive and expects 19million HPs to be operational by 2050 in the UK. One low carbon alternative to HPs are district heating networks, however these require high heat demand densities to be cost effective. (Element Energy, 2015)

In transport, almost 70% of greenhouse gas emissions come from land transport. (Transport Scotland, 2019) The sale of ICE vehicles will be phased out by 2032, according to the current Scottish government policy, with aims to integrate 50% of electric vehicles (EVs) by 2030. Furthermore, falling battery prices will drive down EV prices, as well as supply side signals from car companies moving to 100% EV production also encouraging an uptake of EVs.

From Figure 2, Figure 3 and Figure 4 we can infer that replacing oil and coal fuel sources, from the transportation and domestic sectors, with low carbon electricity sources will have a major impact in terms of reducing the CO2 emissions. However, this will also result in greater load on the electricity system.

Furthermore, it is abundantly clear that diesel as a fuel source for power stations is not in line with net-zero. The planning around diesel power stations is less clear in terms of official targets and closure dates, however it can be assumed that such plants will be closed in the coming decades. In a normal year, the diesel power station plays relatively small yet crucial role for the wider energy system, providing power during the annual periods subsea cable maintenance as well as meeting winter peaks.

Together this creates a clear picture for an altering landscape in terms of additional demand on the electricity system, coupled with the removal of dispatchable fossil fuel resources.

2.4 Problem Statement

The Western Isles energy system is due to undergo further changes in the coming years as it transitions towards a low carbon economy. Energy consumption from fossil fuel sources must be replaced if the region is to meet net-zero targets. How exactly these fuel source changes will impact local renewable energy production is not clear.

For example, EVs and HPs are low carbon technologies, when coupled with a decarbonised electricity supply, that are prevalent in wider national policy targets. The introduction of these technologies may present opportunity for additional local renewable generation. Similarly, local renewable sources could be utilised to produce hydrogen or heat that can be stored over time using thermal energy storages.

The current energy plans for the area rely heavily on the proposed HVDC link and CfD for new local wind parks, both supported via funding at a national level. If the projects are not realised, the replacement subsea cable connection and the future of the diesel power station become even more important.

Furthermore, the system in general and the future impacts on additional local renewable potential have not yet been explored from a whole systems perspective.

The island has a history of local RES production and a desire to match demand with local supply as well as become a future exporter of energy, with a focus on the benefits this can bring to local energy producers and wider community. Understanding the future demands on the system can provide benefit for the local population whilst helping meet the renewable transition targets.

Previous relevant academic literature is discussed in the following section (2.5), alongside industry studies on the Western Isles before the research objective is described in section 2.6.

2.5 Literature Review

2.5.1 Scientific Literature

Islands represent microcosms of the wider global energy system. They are interesting case studies for energy related scientific research as they are both manageable in size as well as often more constrained than mainland alternatives. There exists a wide range of literature on island energy systems, as the unique challenges they face in an energy transition have been investigated from various angles.

Blechinger et al took a global viewpoint and identified 1800 small islands with considerable renewable energy potential, wind and solar. Battery Energy Storage Systems (BESS) were highlighted as a key technology for integration of the variable renewable sources to help replace the commonly used diesel power stations. The techno-economic study concluded that GHG emissions can be reduced in a cost-effective manner and focused on the need to overcome the numerous policy barriers that currently exist if this potential is to be realised. (Blechinger, et al., 2016)

In 2018 Bertheau et al investigated the electrification of the Philippines, a country made up of over 7100 islands and heavily reliant on diesel power stations. The paper used a Python based energy model to optimise future pathways including electrification and a high integration of RES to achieve SDG7. (Bertheau, et al., 2018)

The Scottish Island of Orkney has been used as a case study, alongside the Danish Island Samsø, to investigate the possible integration of both BESS and Thermal Energy Storage (TES). The study used an EnergyPLAN model for both islands and highlighted the stronger impact that BESS has on the electricity sector and its importance in integrating RES, although also concluding that TES can play an important role, especially when aligned with smart energy systems. (Marczinkowski, et al., 2019)

In addition, there has been a variety of research on 100% renewable energy systems. This has been a focus of many scientific papers due to the isolated nature of island systems. For example, M. Alves et al used an EnergyPLAN model for the islands of Pico and Faial, in Azores, concluding that whilst significant penetration of RES was possible at low system costs, only an interconnection between the two islands allowed a 100% renewable pathway to be achieved. (Alves, et al., 2020) This highlights the importance of interconnections for islands when achieving climate targets.

The energy transition on Cyprus was investigated in 2017, with a focus on the impacts from the addition of natural gas into the energy system. (Taliotis, et al., 2017) The authors used an OSeMOSYS energy model to develop 4 different scenarios available to Cypriot policy makers. The economic, security, and environmental impacts of each were assessed and compared with natural gas highlighted as a key fuel choice, for both overall emission reduction and lower electricity prices.

Within much of the previous island literature, there is often a focus on islands that are not connected to any wider transmission grid. The current failed cable on the Western Isles represents an interesting case study for further investigation of the decision making around any interconnection. Furthermore, the impact on island systems from both a high diffusion of HPs and EVs appears to be a gap in literature, despite the apparent market share that these technologies are predicted to assume. There has been previous work on the wider impact of the technologies, the following section summarises some of these.

On an EU scale the electrification of the heating sector has been examined, with regards to effectiveness and possible impact of HPs on the European power system. Thomaßen et al found that electrification was an effective decarbonisation option, with the estimated additional EU HP capacity ranging from 1.1-1.6 TW_{th}, based on current firm power capacity. The study included the UK as an EU member state (Thomaßen, et al., 2021).

The vast changes in the heating sector in the UK was investigated by R. Lowes et al, from the perspective of incumbent actors in the sector and their ability to affect sustainable transitions. The paper noted the current favouring on 'green-gas' solutions due to self-interest from incumbents, despite the scientific literature suggesting that electrification of heating is key for achieving climate targets. (Lowes, et al., 2020)

The aggregated load profile of HPs in the UK was assessed by J. Love et al in 2017, on the back of a large-scale field trial of 700 HPs. The data collection from the HPs is believed to be the largest of its kind to date. The data displayed both morning and evening peaks, with load falling to 40% of the peak value during night-time. After diversity maximum demand (ADMD) represents the aggregated demand across many customers. The paper found ADMD to be 1.7 kWe, in terms of electric load, per customer. This is considerably lower than the maximum capacity of an individual HP's compressor and an important phenomenon when considering demand across numerous customers. It was found that the ADMD fell from 4kW with 1 customer, to 2kW after 40 customers, 1.8kW after 100 HPs and then reaches its final ADMD (to 2 significant figures) once 275 HPs are present. (Love, et al., 2017)

Further work has been carried out on the domestic heat demand in the UK, based on half-hourly gas demand from over 6500 smart meters installed in the UK. The study added a new dimension to previous scientific literature on the possible impacts of electrification of heating that often assumed considered heat demand on a daily timescale or created daily profiles that relied on assumptions as opposed to empirical data. It was concluded that peak heat demand across the UK was 170GW, which was 40% less than previously thought and add further clout to the argument for electrifying heating demand. (Watson, et al., 2019)

A combination of the gas meters and HP field trials was presented earlier this year, again by S.D Watson et al. (Watson, et al., 2021) The UKs half-hourly heat demand was empirically modelled, for both current and future weather conditions, assuming that gas boilers were replaced by a mixture of ground and air source HPs. It was found that in terms of heat demand, HPs may lead to lower peaks as well as higher annual demand, due to operating patterns. Mass adoption of HPs will shift the heat demand from the gas to the electricity sector. As far as could be told, the impacts of this data have not yet been used in local studies, identifying possible impacts on local systems.

Blokhuis et al analysed the impact of both HPs and EVs on the electricity system in Eindhoven, Netherlands. The 2011 study focused on the necessary network investment that would be required to facilitate the new peak demand by 2040. It was calculated that the total electricity peak could more than triple by 2040 and that the network investments for facilitating the expected increases could be between 305-375 million Euros. The paper is relatively old in what is a fast-moving subject, although the conclusions highlight the importance of greater understanding around the impact of these disruptive technologies. (Blokhuis, et al., 2011)

The impact from large-scale penetration of EVs was investigated by Calvillo et al, on a national scale in the UK, using the energy modelling software TIMES. The paper considered different charging patterns, from decentralised 'dumb' charging to centralised 'smart' charging. 'Dumb' charging is the equivalent of charging during peak hours whilst 'smart' charging allows for deferring of the charging. The paper highlighted the importance of 'smart' charging due to the required network investment costs, that are passed on at marginal energy prices to the customer, if charging is conducted during peak hours. Furthermore, it was highlighted that a whole system approach was necessary for analysing EV impact, especially including the power sector. This was due to possible scenarios where peak power demand increases due to EV penetration and is then met by fossil fuel generation sources, that would reduce the climate benefits that EVs bring. (Calvillo, et al., 2020)

A recent study by Heuberger et al found that EV deployment appeared to enable the integration of additional renewable energy, specifically wind power. It was found that EVs can help to lower curtailment

factors, with the greatest benefits realised within the offshore wind sector. The paper was conducted on a national scale in the UK and highlighted the need for further work on the impact at distribution levels. (Heuberger, et al., 2020)

EV have been studied in an island situation, using PLEXOS to model both smart charging (V1G) and vehicle-to-grid (V2G) technology on the island of Barbados. (Taibi, et al., 2018) The paper found that smart charging can facilitate the integration of further RES, as well as utilising V2G to reduce both electricity and ancillary service prices.

With regards to hydrogen and marine transport F. Calise et al conducted energy modelling on the energy system of Sardinia, using EnergyPLAN software. The systems borders were expanded to include marine transport and decarbonisation targets were realised via the installation of small decentralised renewable generation, mainly wind and solar, as well as increasing use of storage technologies. (Calise, et al., 2021).

A. Pfeifer et al reviewed recent literature on different approaches to achieving zero emission marine transport. They analysed islands' capabilities to provide the energy required for the vehicles, conducting technical and economic analysis for both hydrogen and electric ferries. The research found that for shorter ferries electric solutions provide more cost effective, whilst hydrogen was favoured for long durations. The paper noted that the modelling of the hydrogen production could be improved, with greater focus on the dynamics between the electrolyser and hydrogen storage. (Pfeifer, et al., 2020)

2.5.2 Studies on Western Isles Energy System

Active Network Management, ANM, uses control system to manage generation and load on local systems, with the aim to keep the electricity systems within their physically constrained limits. The technique can be used to further integrate renewables into energy systems via storage and other flexible resources and is currently being used on the Island of Orkney and Isle of Wight. (SSEN, 2021) In 2017 Xero Energy completed an ANM Study for Community Energy Scotland. (Xero Energy , 2017) The study aimed to investigate the likely curtailment of future generation assets due to the constraint of the subsea cable rating. The work was before the current failure of the subsea cable and did not include future increase in electricity demand due to the impact of net-zero. The issue of grid constraints can have huge impacts on local energy systems. Despite this, research often considers areas as single busbars, assuming no limits in terms of transmitting electricity throughout distribution systems. (Pean, et al., 2016)

In 2019 a feasibility study was conducted into the option for using hydrogen on the local ferries, Scottish Western Isles Ferry Transport using Hydrogen or SWIFTH_2. The report highlights two routes in the region, Barra-Eriskay and Stornoway-Ullapool as the most viable ferry routes for hydrogen conversion. (Trust, Point and Sandwick, 2019)

2.5.3 Literature Review Summary

The previous literature studied highlighted that island systems can achieve domestic decarbonisation targets via electrification alongside the implementation of high levels of RES and BESS, as well as decarbonising long haul marine transport via the production hydrogen. The use of energy modelling as a tool for analysing systems is prevalent throughout literature and will be utilised as a key part of the methodology for the following work. Furthermore, scenario analysis has been used to effectively compare possible pathways for the energy systems in question and this technique will also be incorporated into the thesis, to assess the future impacts on renewable potential of both the new subsea cable and the removal of dispatchable diesel power from the Western Isles energy system. At least in the short-term, electrification is likely to be dominated by the transformation within heating and transport sectors, via HPs and EVs. The impacts of these technologies have been studied at country-scale, however, considering their addition on local systems appears not to have been covered to date. Additionally, HP adoption has reached high enough numbers to allow for data driven field studies, the conclusions of which will be incorporated into the thesis.

As RES is implemented throughout the world at a growing rate, local systems are faced with the challenge of continuing the energy transition in an economic fashion, often without the previous financial support mechanisms that were offered during the earlier years of the technologies adoption. Previous literature implies that electrifying the heating industry is likely to require additional peak electricity demand, whilst EVs are a younger technology and themselves represent a more flexible resource that will add greater demand to the system but also potentially offer greater flexibility too. This represents possible opportunity for further RES penetration, due to the additional electrical demand and possible use of flexible EV smart charging.

This study aims to combine these two technologies when considering different pathways that the Western Isles faces. These pathways include the potential removal of the diesel power station from the electricity generation mix, as well as the current interconnection between the island and the mainland. Diesel generators are highlighted in literature as common generation technologies for islands, which can be replaced by the combination of RES and BESS. However, the timing of the complete removal of these fossil fuel generators will have impacts on the wider energy transition.

Due to time constraints, local production of hydrogen to meet additional sectors such as marine transport, or the conversion of the Stornoway local gas grid to 100% hydrogen, was not included in the work.

2.6 Research Objective and Methodology Outline

The thesis aims to investigate the potential for future local renewable generation on the island of Lewis and Harris up to 2035. A high diffusion of HPs and EVs into the region will be assumed as the following topics are explored:

- New interconnection to the Scottish mainland.
- Removal of on island electricity generation from diesel power stations.

Due to time constraints, the energy model focused on the electricity system, with heating and transport demands included only through the additional HPs and EVs. Broadening the representation of these sectors in future work would provide a further step towards a whole systems approach.

A baseline PLEXOS energy model was initially created, and validated, following a through period of data collection for the region. Several scenarios were then explored, with the initial four considered the main results of the thesis. Sensitivity analysis was then used to gain further insight into the mainland electricity prices. The scenarios are further explained in section 4.2, however brief descriptions are as follows:

1. Scenario 1: Baseline. New 30MW cable connection.
    a) With the diesel power station in use for the duration of the modelling.
    b) Assuming that the diesel power station is closed in 2030, post RIIO2.
2. Scenario 2: Additional capacity. As scenario 1, apart from a larger cable capacity of 60MW.
    a) With the diesel power station in use for the duration of the model.
    b) Assuming that the diesel power station is closed in 2030, post RIIO2.
3. Scenario 3: Baseline + EV smart charging. Identical to scenario 1(a), with the inclusion of deferable load for the EVs.

3 Methodology

3.1 Energy Modelling

Analysing energy systems is becoming ever more relevant as the world enters an age of climate emergency. The need to replace incumbent fossil fuel energy generation with low carbon technologies is now a global focus. Energy systems modelling is an analysis technique that uses mathematical computation to represent the energy system in question and allow for investigation into the system to aid future decision making.

As intermittent resources become a higher proportion of the energy systems in question the need for high temporal (e.g., hourly) modelling increases, to better represent real life dynamics.

For this thesis. PLEXOS was used as the modelling tool.

3.2 PLEXOS Integrated Energy Model©

PLEXOS is an energy modelling software, developed by Energy Exemplar. It is a bottom-up tool that can be used for multiple purposes: Investment Decision Support, Operation Decision Support, Power System Analysis Tool and Scenario Analysis. Temporal resolutions are user defined, from 24 hours up to high resolutions of 1 second, as is the time horizon, with options from 1 day to over 50 years. Model sizes can range from single projects or aim to investigate global systems.

2018 review of 75 different modelling tools with regards to handing high shares of variable renewables. (Ringkjøb*, et al., 2018) In comparison to other tools the flexibility and breadth of options for PLEXOS is a notable strength. For example, it was noted it had no limitations in terms of generation, storage, and emissions options. Furthermore, PLEXOS offers multiple alternatives in terms of electricity grid representation and market options, as well as the ability to model energy vectors such as heat or fuels including biofuels or hydrogen.

PLEXOS offers four different simulation engines:

- Long Term Plan, LT Plan. This is used for finding least-cost combinations of new technologies, retirements, and transmission upgrades by minimizing the net present value (NPV) of the total system cost subject to system constraints or emission limits.
- Project Assessment of System Adequacy, PASA, can be used to plan, or model, maintenance schedules and random outages.
- Medium Term schedule, MT Schedule, is a simulation based on temporal simplification. The results here can be stand along, or to decompose medium term constraints and objectives that can be passed on to the ST Schedule and therefore fully accounted for, i.e., hydro release policies.
- Short Term Schedule, ST Schedule. This simulation is a fully chronological unit commitment and economic dispatch model based on mixed-integer programming.

Previous literature has used PLEXOS across multiple topics, including renewable integration and the impact of additional interconnection between the UK and France (Pean, et al., 2016), the Irish electricity system (Calnan, et al., 2013), leveraging flexibility from EVs to integrate solar and wind on the island of Barbados (Taibi, et al., 2018), and investigating the integration of intermittent renewables in the West-European power system (Brouwer, et al., 2016).

For this thesis, the LT Pan simulation will be used to provide least-cost expansion planning for the different scenarios, whilst the ST Schedule was used to validate the baseline model.

The modelling tool is, however, not open-source and requires a license to run the software. This can be disadvantageous when compared to open-source models that can be shared and critically analysed with ease by the wider energy modelling community.

3.3 Model Description

For this thesis, only the areas of Lewis and Harris will be included in the analysis as mentioned in section 2.1. Due to the two subsea cables that join the islands to the mainland (Figure 5), the electricity system on Lewis and Harris can be considered as separate from that on the southern area of North Uist, Benbecula, South Uist and Barra. Figure 6 displays the areas of Lewis (left) and Harris (right) in red. Conclusions of the work may be relevant to the wider area of the Western Isles, although local differences should be taken into consideration.

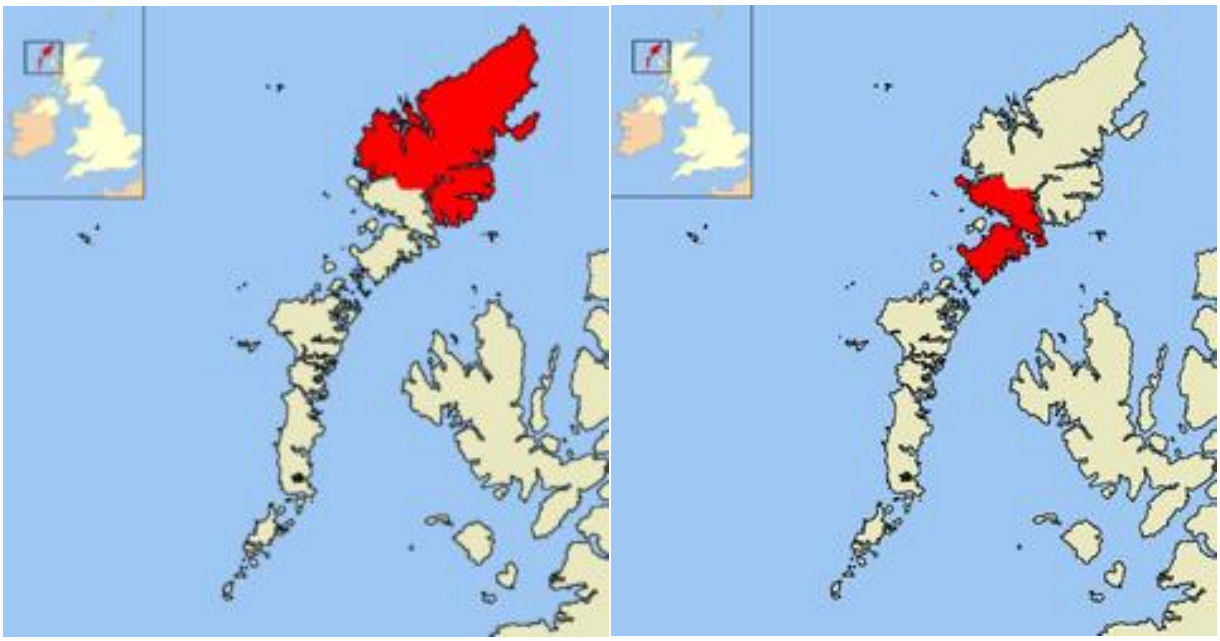

Figure 6 Images of areas of Lewis and Harris

Whilst PLEXOS is capable of optimising multiple sectors at once (electricity, heat, transport etc), the model was set up to optimise only the electricity system in the future scenario analysis, with additional heat and land transportation demands added exogenously. The following sectors were included in the PLEXOS model, which is visually represented in Figure 7, on page 25:

- **Electricity**. The transmission and distribution grids are represented, as well as current domestic, commercial, and industrial electricity demand. Local installed electricity generation sources were included in the model, as well as future expansion candidates in terms of addition wind, solar and BESS, chosen due to their current presence in the system or technological maturity.
- **Domestic heating** is included via the additional of an assumed increasing number of heat pumps, whose demand is met via additional electricity load to the system.
- **Domestic land transportation** is included in terms of an assumed increasing number of EVs, represented by their demand in terms of kms over time. These add additional electricity load to the system via charging stations.

The model includes emissions in terms of CO_2eq. for both the fossil fuel generation on the island as well as representing the emissions from the mainland grid in terms of an average emission factor.

The above sectors were chosen to accurately portray future additional electricity demand. Heavy duty transport, for example, represents a part of the energy system that may be electrified, however the competition between electricity, hydrogen and e-fuels provides a less certain picture within this industry and therefore electrification was not assumed.

Furthermore, the agriculture industry is omitted form the study, as well as any marine and air transportation. Whilst future impacts on electricity was investigated with regards to domestic heating, and transport, the study did not include the further electrification of industrial loads or heavy-duty land transport on the island. Information on the industrial sector, and specifically any plans for further electrification, proved difficult to find and due to case-by-case specific with regards to each industrial

process, making assumptions here without better data could be misleading. Gaining further insights here would provide a fuller picture and be a sensible next step.

3.3.1 Other relevant technologies

Offshore wind has also reached technological maturity in recent years and is likely to play a major role in Scotland's future energy system. However, the current sites around the Western Isles have not yet been part of the Crown Estate rounds of leasing. Whilst there is hope that the future leasing rounds will include the areas surrounding the Western Isles, the size of these potential projects are in GW and therefore may require direct transmission to the mainland without impacting the local systems. Due to these reasons, only onshore wind was included in the scenario analysis. (Crown Estate Scotland, 2021) (CNE-Siar, 2020)

Wave and tidal power are topics that have been discussed in length in previous literature with regards to their potential in Scotland (Neill, et al., 2017), and specifically the west coast. (Frost, et al., 2018) (Assessment of the Grid Capacity Sharing Potential for Wave and Wind Energy Conversion Systems in the Outer Hebrides of Scotland, 2013)A 40MW wave power project reached planning stage in 2012, Lewis Oyster Array. (Aquamarine Power, 2012) However, the project was never realised, and both technologies have stalled in recent years. The Scottish Island of Orkney, in partnership with EMEC, is considered a world leader in terms of tidal power, with recent projects including a 4MW floating tidal turbine. As wave and tidal power matures, they could provide an additional major source of renewable energy which could be added into the model in future work. (Draper, et al., 2014) (The Scotsman, 2020)

In a similar fashion, a large-scale pumped hydro scheme reached planning stages in 2016, however was never realised. (Energy Storage, 2016) The benefits of local pumped hydro on an energy system with high levels of wind power generation has been explored in previous literature and, again, could be added to the model in future work. (Kapsali, et al., 2017)

Furthermore, when considering batteries, it was assumed that lithium-ion technology would continue to dominate the electricity storage market. If, as some predict, new technologies such as solid-state or flow batteries are to break into the market their inclusion could be interesting, taking into consideration any techno-economic differences. (Zhang, 2019)

Finally, the option of including a dispatchable generator capable of producing low carbon electricity at a scale like the current diesel generators (e.g., via biofuels or hydrogen) was not included. Biofuels are limited on the island and the concept of fuel switching from diesel to hydrogen is still in its infancy. However, hydrogen use cases are a major focus in today's world and if this technology were to mature and accurate techno-economic estimates available then the option could be included.

3.3.2 Reference Energy System diagram

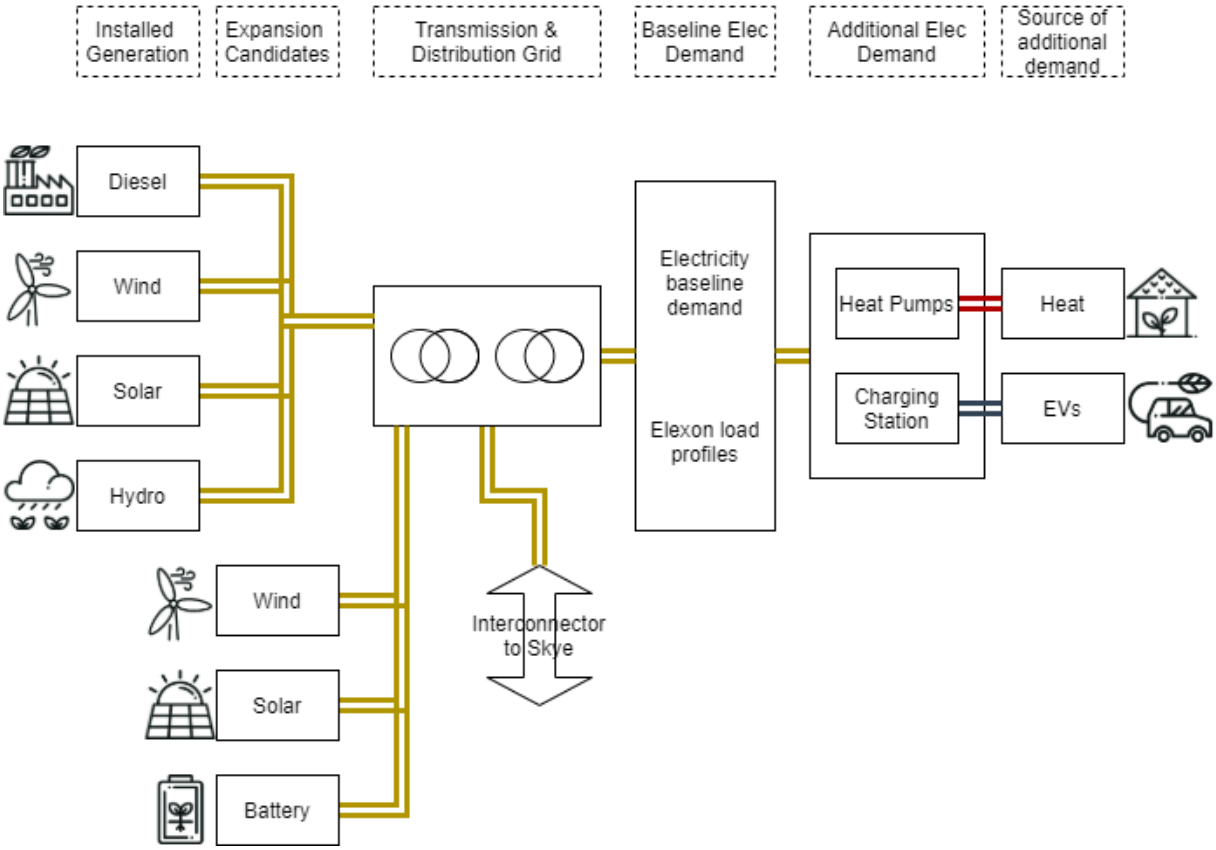

Figure 7 Reference Energy System Diagram

The diagram represents the energy system as it is modelled in PLEXOS. The main parts of the model are detailed further in the following sections.

- Transmission and distribution grid – section 3.3.3
- Baseline demand – sections 3.3.4
- Additional demand – sections 3.3.5, 3.3.6
- Installed Generation – section 3.4
- Mainland electricity prices – section 3.5
- Expansion Candidates – section 3.6

3.3.3 Representation of the Electricity Network

The distribution grid on the island includes cables at the following voltages:

- 132kV – **HV transmission**. There is one 132kV line that connects the Harris and Stornoway grid. Any electricity that is provided to the island via Ardmore, Skye, is first transmitted from the Scottish mainland through 132kV lines, however these are not included in the model.
- 33kV – **HV distribution**. 33kV lines are used throughout the island. The 33kV schematic is shown in Annex 9.1.1 and has been simplified within the PLEXOS model. The 33kV network is then stepped down to 11kV via 10 Primary Substations (PSS). These substations are included in the model, alongside 3 additional transformers (2x 132/33kV and 1x 33/33kV).
- 11kV and lower – **MV & LV distribution.** 11kV lines are then used to distribute electricity from each PSS to local transformers that drop the voltage to 400V or 240V. The 11kV schematics were available via SSEN Connections portal and were assessed to help define the demand areas, as well as better understand the larger industry demands on the island. Demand and distributed generation (<100kW) are aggregated to this level. No cables lower than 11kV are represented.

Figure 8 shows a schematic from PLEXOS of the electricity grid, as represented in the model. The lines (blue = 132kV, green = 33kV) and transformers are included in the schematic. In the model both the line and transformer objects include ratings (MW) that constrain the power flows on the island. The constraints are detailed in Table 2 and Table 3. A similar figure is shown in the annex, including the generators added to each node.

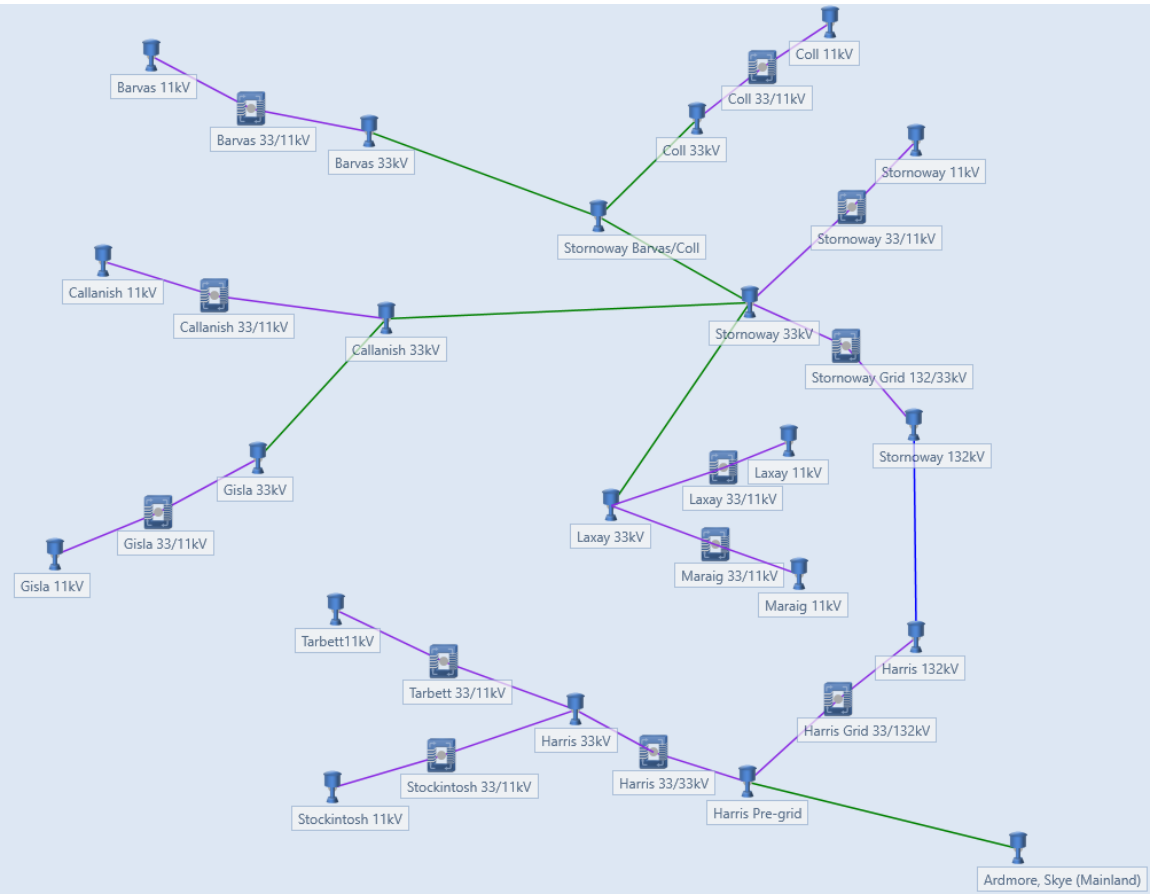

Figure 8 Schematic from PLEXOS of representation of electricity network

Figure 9 displays the distribution grid once again, this time roughly overlaid on the map of the Western Isles. In the figure below the different voltage ratings are represented by the different colour lines (blue=132kV, green=33kV, red=11kV).

Figure 9 Distribution Grid representation, overlaid on map of Western Isles.

The electricity load across the island is met by the different 11kV nodes. The demand across the island was divided in six different demand regions to best fit the configuration of the 11kV network at a resolution that was appropriate for the available data sources. This process is described further in section 9.2.1 and 9.2.2, annex.

These six regions are detailed in Table 2, alongside the different PSS and their ratings, available from SSENs Long Term Development Statement (LTDS). (SSEN, 2020) The three further transformers included in the model are detailed in Table 3. All ratings provided were in apparent power, MVA. A 95% power factor was assumed to convert this to real power.

Table 2 Primary Substations represented in PLEXOS model, by Demand Region.

Demand Region	PSS (33/11kV transformer)	Nameplate Rating (MVA)
Stornoway	Stornoway	3x8
	Arnish (back-up)	24
Northeast Lewis	Coll	4
Northwest Lewis	Barvas	2x2.5
Southwest Lewis	Callanish	4
	Gisla	1
South Lewis	Laxay	2.5
	Maraig	0.2
Harris	Tarbett	2.5
	Stockintosh	1

Table 3 Remaining transformers represented in PLEXOS model.

Connecting Nodes	Transformer voltages (kV)	Nameplate Rating (MVA)
'Harris Pre Grid' to 'Harris Grid'	33/33	5
'Harris Grid' to 'Harris 132kV'	132/33	60
'Stornoway 132kV' to 'Stornoway 33kV'	132/33	30

As well as the transformers, the following cables were also included in the model, Table 4, along with ratings for the different seasons. Including exact power factors for cables would require a detailed power systems model and was out with the scope of this thesis. However, to acknowledge that there will be considerable reactive power in the cables, the following power factors were assumed for each cable, based on further information from the SSEN LTDSs and via email dialogue with SSE, to convert the ratings from apparent power (MVA) into active power (MW). (SSEN, 2020) For the subsea cable, it is assumed that an annual maintenance period of 2 weeks is required during the high summer and a further week in autumn, indicated from information provided by both SSEN and wind generators on the island.

Table 4 Cables represented in PLEXOS model.

Connecting Nodes	Voltage (kV)	Ratings (MVA)			Power Factor	Comment
		Winter	Spring/Autumn	Summer		
'Ardmore' to 'Harris Pre Grid'	33	23.4			0.8	Subsea cable, currently failed
'Harris 132kV' to 'Stornoway 132kV'	132	85.1	78.9	68.1	0.85	HV transmission line
'Stornoway 33kV' to 'Laxay 33kV'	33	11	10.2	8.8	0.85	
'Stornoway 33kV' to 'Callanish 33kV'	33	11	10.2	8.8	0.85	
'Callanish 33kV' to 'Gisla 33kV'	33	7	6.5	5.6	0.9	
'Stornoway 33kV' to 'Barvas/Coll'	33	11	10.2	8.8	0.85	
'Barvas/Coll' to 'Barvas'	33	11	10.2	8.8	0.85	
'Barvas/Coll' to 'Coll'	33	11	10.2	8.8	0.85	

3.3.4 Electricity Demand

In the UK, electricity payments are settled between generators, retail and suppliers using the Balancing Settlement Code. This is administered via Elexon, a private company acting as part of the National Grid. Elexon uses 8 different profiles to predict electricity demand for end-user types. (ELEXON, 2018)

These Elexon load profiles were used to vary electricity demand temporally, within annual periods. Since 2017, four generic profile classes are used to represent large populations of similar customers:

- Class 1. Domestic, Unrestricted. A single tariff customer. Annual consumption of ~4-Megawatt hours (MWh). A daily profile example for class 1 is shown in Figure 10.
- Class 2. Domestic, Economy 7. A dual tariff customer, usually using a storage heater to take advantage of cheaper electricity prices during the night. Annual consumption of ~7MWh
- Class 3. Non-domestic, unrestricted. Annual consumption of ~13MWh
- Class 4. Non-domestic, Economy 7. Annual consumption of ~25MWh

Classes 1-2 represent domestic users, whilst classes 3-4 represent most commercial and industrial customers. Industry customers with maximum demand above 100kW, as well as previous profile classes 5-8, are required to use half hourly meters.

The combination of these eight classes provided the basis for the electricity demand at each node.

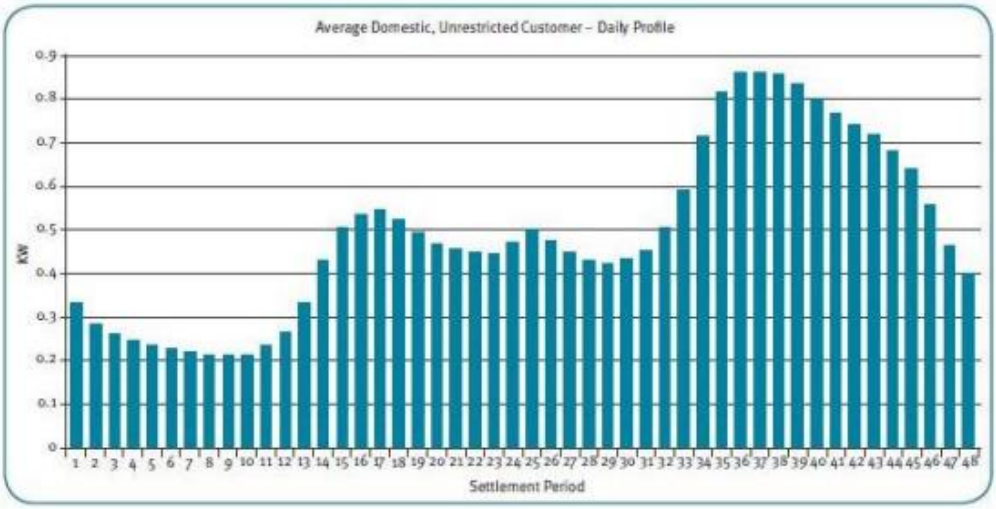

Figure 10 Example half hourly load profile for Elexon profile class 1, weekday

The load profiles are divided into three separate day types; weekday, Saturday, Sunday; as well as five season types; winter, spring, summer, high summer, and autumn. Public holidays are assumed to have the same profile as Sunday. The start and end dates for each season are shown in Table 5, for 2020.

Table 5 Elexon load profile seasonal dates, 2020

	Start	End	Days	Description
Winter		28/03/2020	88	Up to and including the day before-clock change from GMT→BST[3] (in March)
Spring	29/03/2020	17/04/2020	48	From day of clock change, up to and including the Friday before start of summer period
Summer	18/04/2020	26/06/2020	70	10-week period, starting on 16th Saturday before August Bank holiday
High Summer	27/06/2020	09/08/2020	44	6-week and 2-day period from the 6th Saturday before the August bank holiday
Autumn	10/08/2020	24/10/2020	48	Monday after August Bank Holiday, up to the day before clock-change from BST→GMT
Winter	25/10/2020		68	From the day of the clock-change from BST to GMT (in October)

[3] GMT refers to Greenwich Mean Time, BST refers to British Summer Time

For each demand region, the number of users in each category was estimated and then the annual profile was scaled up to reflect historical peak data from each PSS, considering losses at the LV and MV distribution levels (SSEN, 2021). It was assumed that these loses were 5% of total load, with this added to each demand area. (SSEN, 2019) (OFGEM, 2009)

Table 6 displays the number of customers within each load profile class, split by demand region. Class 1-4 customer numbers were available via BIES statistics (Department for BEIS, 2020a), whilst industrial customers 5-8 were estimated by analysing SSEN 11kV schematics and LTDS information. (SSEN, 2020)

Table 6 Number of customers per Elexon Profile class

Demand Region	Customers per Elexon Profile Class (no.)							
	1	2	3	4	5	6	7	8
Stornoway	4663	1738	614	68	21	23	11	17
Northeast Lewis	1362	309	112	13	8	0	1	0
Northwest Lewis	1134	370	58	7	8	0	0	0
Southwest Lewis	1338	297	114	13	7	0	1	0
South Lewis	999	230	58	7	8	1	0	0
Harris	1103	502	173	20	9	2	0	1

Figure 11 shows the estimated annual demand for the Stornoway region, before distribution losses are accounted for. Similar profiles were produced for the remaining demand regions, providing the baseline electricity demand in the model.

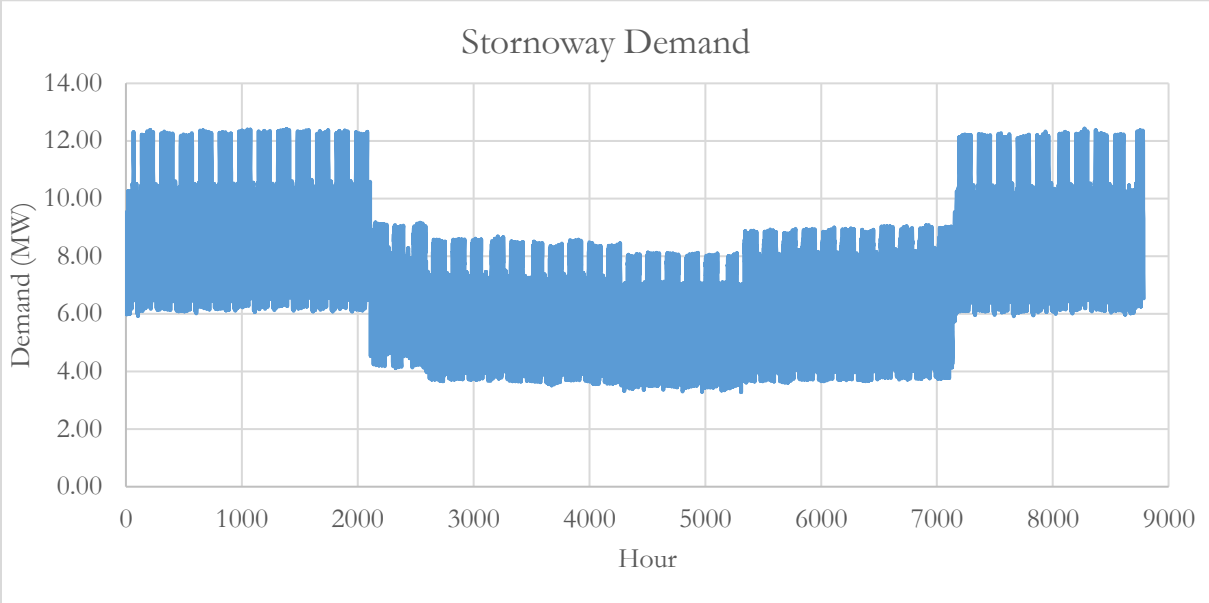

Figure 11 Estimated demand for Stornoway Demand Region, 2020

3.3.5 Additional Electricity Demand from Domestic Heat Pumps

Previous analysis of the UK HP pump field trial was used as the basis for additional electricity demand from the electrification of heating. (Watson, et al., 2020) The data used in the studies was the largest data collection from HP metering in the UK, and possibly globally. The following steps were followed to create half-hourly heat demand profiles, per customer, for the PLEXOS model:

1. The average daily temperature was calculated from the Met Office Integrated Data Archive System (MIDAS) weather data, shown in Figure 12, including data from 2011-2020.

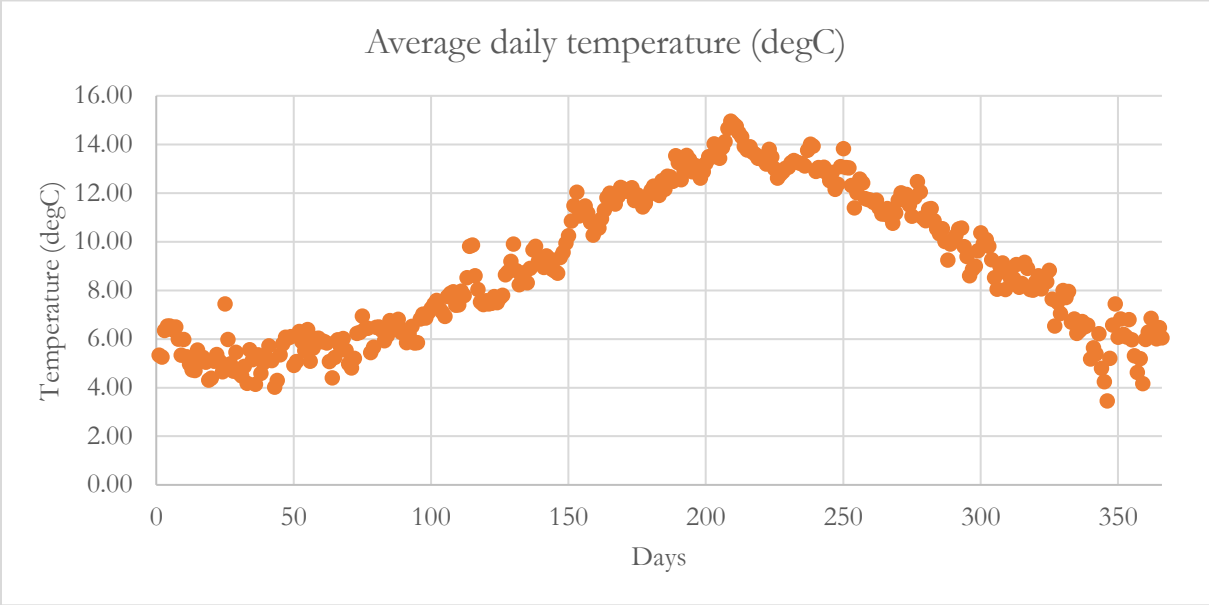

Figure 12 Average daily temperature, data from Met Office MIDAS

2. The following daily regression equations were used to calculate the daily total heat demand in kilowatt hours (kWh), shown in Figure 13. This includes demand for space heating and domestic hot water:

$$Daily\ heat\ demand = -5.55 * Average\ Daily\ Temperature\ +\ 84.3\ (if\ ADT < 14.3)$$

$$Daily\ heat\ demand = -0.79 * Average\ Daily\ Temperature\ +\ 16.1\ (if\ ADT \geq 14.3)$$

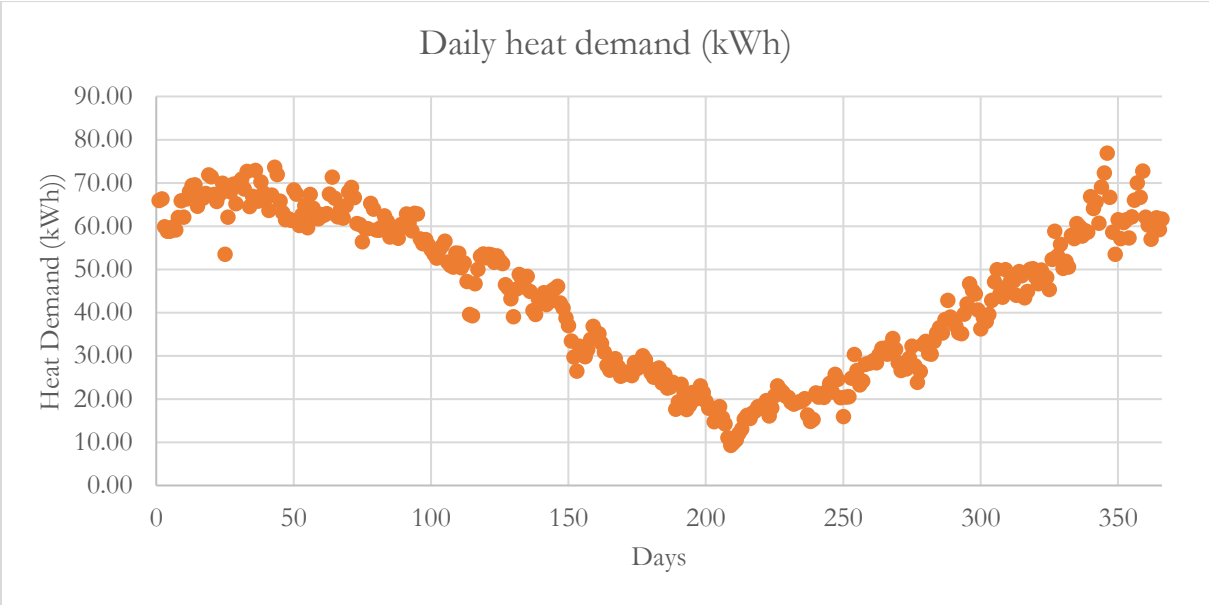

Figure 13 Daily heat demand, kWh

3. To vary the heat demand across time within each day, the following normalised half-hourly profiles were used, Figure 14. There are 8 different daily profiles, corresponding to the average temperature that day, split into 3-degree bands. For each temperature band the summation of the values is 1, with the curve representing the spread of the daily demand. Therefore, the shape is more relevant than the maximum height. Lower temperatures result in flatter profiles, meaning that demand is more constant through the day, however there are peaks during both morning and evening hours.

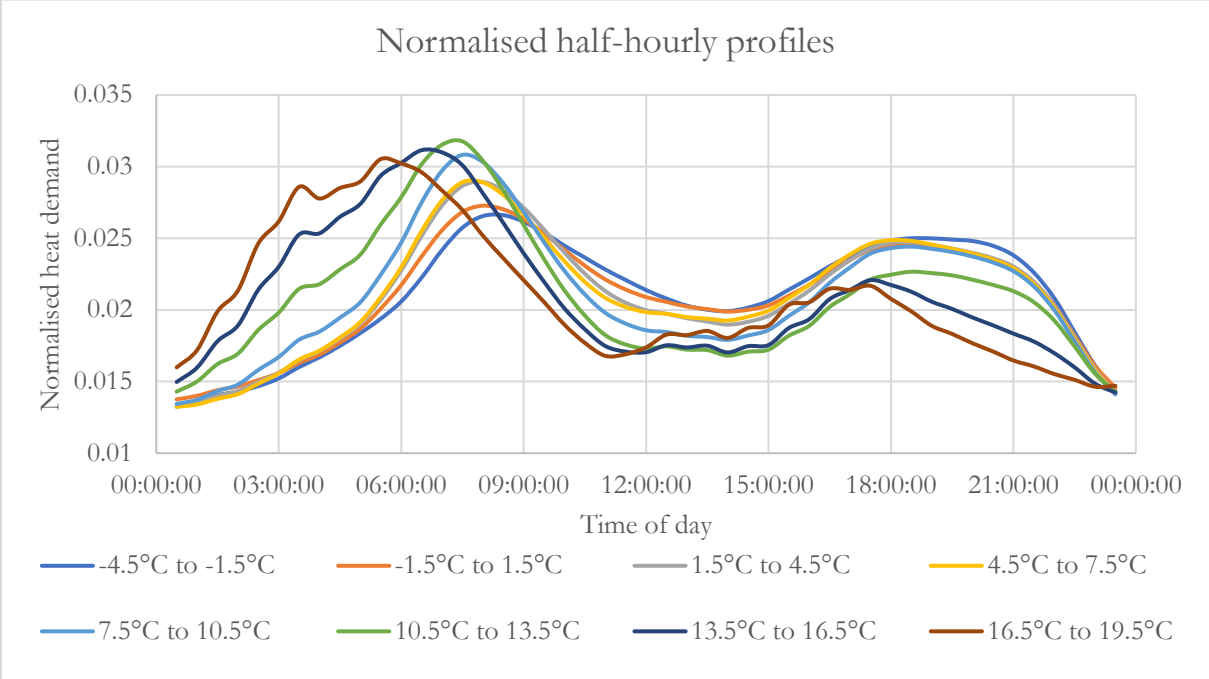

Figure 14 Normalised half-hourly heat demand, by temperature band.

4. The final heat demand profile for one year is displayed in Figure 15. The peak demand per heat pump rises above 5 kilowatts thermal (kW_{th}) during the coldest part of the year.

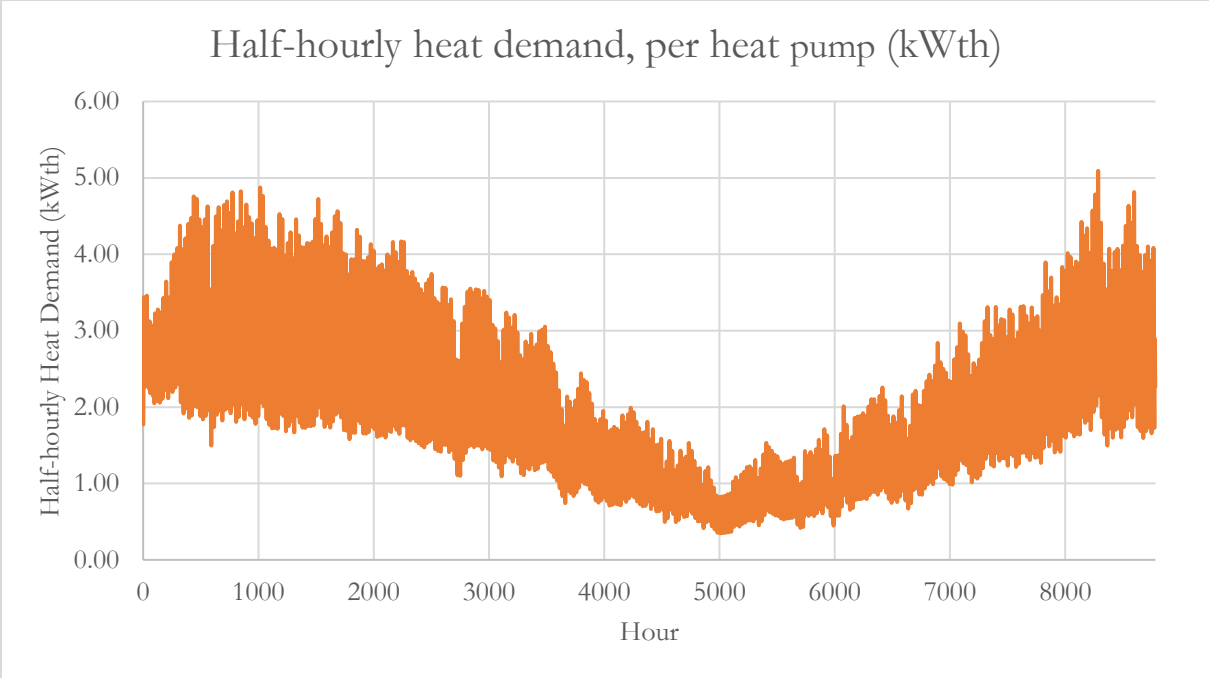

Figure 15 Half-hourly heat demand (kW_{th}) of an average HP over a year

5. In PLEXOS, this heat demand is met via a heat plant object, connected to both the 11kV electricity demand node, and a heat demand. Here, the HP's Coefficient of Performance (COP) is included as a characteristic in PLEXOS which directly impacts the electrical load that is placed on the system to meet the heat demand.

The annual heat demand from the HP comes to just above 16MWh of heat. This correlates well with the Energy Performance Certificates (EPC) database, if energy efficiency efforts continue to ensure that homes with lower band ratings (Band F, G) are improved upon. (Statistics.gov.uk) A detailed analysis into the housing stock would provide further insight, such as homes that are unable to be improved or unable to be fitted with HPs and may rely on direct heating only. This situation would both increase the customers electricity bill and the demand on the electricity network and as such it has been assumed this will be limited.

To forecast heat-demand forward in time, the daily temperature per year was assumed to follow the profile shown in Figure 12 for each year. The result of this may be that the coldest days of the year are not considered, due to aggregating multiple years of data. However, for the purpose of this study it is deemed appropriate and any impacts from extremely cold weather could be included in work focused on system resiliency. Additionally, this assumption also does not consider any future climactic change in the region.

The two main HP options are Ground Source Heat Pumps (GSHP) and Air Source Heat Pumps (ASHP). The field study data upon which the above methodology is based found that the split between ASHPs and GSHPs was 75% to 25%, respectively. (Watson, et al., 2020) It is assumed that the split will be similar within the Western Isles.

Whilst GSHPs have relatively constant COP throughout the year, ASHPs COP varies with outdoor air temperature. This can add additional electrical load during colder times of the year and should be taken into consideration. The current COP used in the model is 2.5, the current minimum design requirements for UK RHI installations, and was deemed an appropriate assumption, especially for colder months when the COP is at its minimum. (Carroll, et al., 2020)

3.3.6 Additional Electricity Demand from Domestic Electric Vehicles

Electric Vehicles present significant challenges for future electricity networks. As high numbers of EVs are expected, their charging patterns will be extremely important with regards to when the additional electricity demand occurs. PLEXOS allows for modelling of EVs through two main addition objects:

- Electric vehicles. These represent the cars themselves, characterised by the following key parameters:
    - Demand (km over time)
    - Capacity (kWh)
    - Efficiency (Wh/km)
    - Min/max state of charge, SOC, (%)
    - Charging efficiency (%)
- Charging stations. These link the EVs to the grid, the following characteristics determine the impact the EVs have on the electricity system:
    - Share (% of EV's present at the station over time)
    - Max charge rate (kW)
    - Charge efficiency (%)
    - Maximum deferment (%), V1G
    - Deferment period (hours), V1G

The final characteristics for the charging station above represent the modelling of 'smart' charging (V1G), where a set % of the car's charging demand can be shifted in time. For this study, the EV modelling incorporated mainly direct charging (V0G). V0G was used for all scenarios with an assumed preference for off-peak charging. V1G was then applied to one of those scenarios. Vehicle-to-grid (V2G) could not be fitted to the scope of this thesis because the potential of V2G contains even larger uncertainties than V0G and V1G, with the biggest obstacle being consumer willingness to let their EVs be discharged. As smart charging capabilities and charging patterns are better understood in the coming years this is an area for further future work.

In 2018 OFGEM published Future Insights Series, Implication of the transition to Electric Vehicles. (OFGEM, 2018) Some key insights into the charging patterns and EV ownership in general are summarised:

- 87% of EV charging occurs at home (~3-11kW), with a further 8% occurring at work. Around 1% of EV charging occurs at 'En-route' charge points, often considered 'rapid chargers' (~40-120kW), shown in Figure 16.

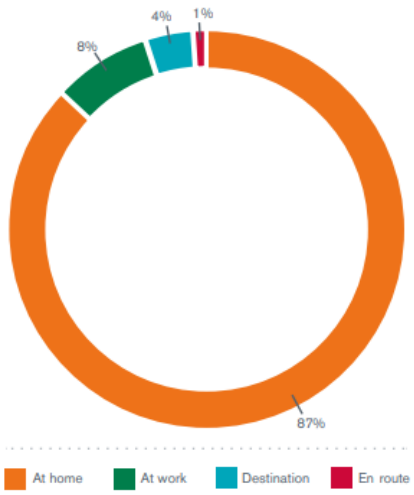

Figure 16 EV charging activity by location (OFGEM, 2018)

- Current EV owners often charge their vehicles during peak hours. This pattern is often referred to as 'dumb' charging and it is widely acknowledged that allowing these patterns with higher levels of EV uptake will lead to electricity networks failing if they are not substantially reinforced.

- A move towards 'smart' charging will help protect the electricity networks. This can be achieved by encouraging charging during night-time hours through market forces, or matching daytime charging with solar installations.

Several assumptions were made with regards to the charging patterns of EVs in the model, based on the sources above and the fact that the EV uptake is of domestic vehicles. Most of the charging was assumed to occur during night-time hours, when electricity demand is usually low and in line with the OFGEM report findings. Furthermore, EVs will be charged at home, or at 'slow' chargers.

The % share of EV's present at its respective charging station, using a normal distribution between the hours of 1800-2400 for cars being connected and between the hours of 0400-0900 for cars being disconnected. Each car was assumed to charge, on average, every 3rd day, based on daily driving demand and EV capacity.

It was assumed that each car had an annual demand of 7100miles (14001km), as per a local study from the nearby islands of Barra and Vatersay. (Local Energy Scotland, 2020) With the EV characteristics used (Table 7) the average annual electricity demand per EV is 2.83MWh.

This driving demand was spread out temporally using annual daily traffic flow statistics for the UK. The data provided monthly, weekday and hourly indexes (1=average) in terms of small-medium vehicle traffic flow on all UK roads from 2016-2020. Monthly and weekly indexes are shown below as well as an example hourly indexes (for Wednesday), Figure 17. (GOV.UK, 2021a)

Figure 17 Monthly, weekday and hourly (Wednesday) traffic flow indexes

The following parameters were used for the EVs themselves, Table 7, considering projected future advancements in EV technology.

Table 7 EV characteristics

Characteristic	Value
Capacity	48 kWh
Efficiency	200 Wh/km
Min/Max SOC	20/100 %
Charge efficiency	99%

3.4 Local Generation

As well as the interconnector supplying electricity from the mainland the island has the following local generation sources, which were added to the PLEXOS model as generators.

3.4.1 Fossil Fuel

There are two diesel power station on Lewis and Harris, both location near Stornoway. As dispatchable technologies they are not constrained in terms of capacity factors.

Table 8 Diesel Power Station on Lewis and Harris

Name	Total (MW)	Efficiency	Location (node)	Fuel	Year built
Battery Point	25.5	35%	Stornoway	Diesel	1954
Arnish	10.3	35%	Stornoway	Diesel	2000

The diesel fuel was assumed to have a price of 20 £/gigajoule (GJ) and a carbon content of 81kg/GJ of CO2eq. (Element Energy, 2014) (Pietzcker, et al., 2021). An additional carbon tax was applied to the diesel fuel, on the assumption that the UK's new Emission Trading Scheme (ETS), which has replaced their involvement in the EU ETS following Brexit (Department for BEIS, 2021), will follow current EU ETS forecasts and reach 110€/tCO_2 by 2030. (Bloomberg, 2021) This rise was assumed linear and extrapolated forward to 2035.

3.4.2 Wind Turbines

There are ten installed wind parks on Lewis and Harris, with capacities of 100kW or more. These are displayed below in Table 9. Community windfarms are referred to as CWF. (Department for BEIS, 2021) (UK Renewables, 2021) (The Wind Power) Table 12 details operation and maintenance costs for wind turbines.

Table 9 Wind turbines installed on Lewis and Harris.

Name	Total (MW)	Turbine Size (MW)	Num (#)	Hub height[4] (m)	Turbine type	Location (node)	Year built
Arnish Moor	3.9	1.3	3	60	Nordex N60/1300	Callanish	2007
Beinn Ghrideag CWF	9	3	3	70	Enercon E82/3000	Stornoway	2015
Bridge Cottages	0.1	0.1	1	-	-	Stornoway	2014
Creed Business Park	0.33	0.33	1	44	Enercon E33/330	Stornoway	2014
Horshader CWF	0.9	0.9	1	55	Enercon E44/900	Callanish	2012
Galson	2.7	0.9	3	55	Enercon E44/900	Barvas	2015
Pentland Road[5]	18	2.3	6	70	Enercon E82/3000	Stornoway	2013
Tolsta CWF	0.9	0.9	1	55	Enercon E44/900	Coll	2013
Horgabost	0.1	0.1	1	-	-	Harris	2016
Monan CWF	1.5	0.5	3	30	Windflow 33/500	Harris	2015

Wind turbines dominate the energy system in terms of installed renewable generation capacity on the Western Isles. This, alongside their variable nature, means that representing their output across time

[4] Hub heights were estimated from manufacturer ranges.
[5] Currently limited to 13.8MW due to DSO grid constraints.

accurately is extremely important. Generation from the turbines on the island were calculated based on hourly MET office wind speed data sets. (MET Office, 2019)

The dataset available from the Stornoway airport weather station was deemed the most reliable source available, and preferable to using online sources such as the global wind atlas, for the Western Isles. (DTU, 2021) A similar methodology has been used in previous literature, where a hindcast for onshore wind generation in Scotland was modelled from the MIDAS database to infer future network capacity implications. (Commin, et al., 2017)

Recorded wind speeds from 2020 were used for the baseline model. For future scenarios year-long samples were stochastically selected from the last 10 years of data, 2011-2020.

Wind speeds were converted to power generation for each of the wind turbine sites using the following steps:

1. Wind speeds provided by Met Office in knots. These were first converted to m/s.
2. Power curves were found for each of the turbine types present on the island. (The Wind Power)
3. Stornoway airport wind speed measurement takes place at 10m. The wind speeds were then altered to reflect the wind speed at the different turbine heights, using the following formula:

$$v_2 = v_1 * \frac{\ln\left(\frac{h_2}{z_0}\right)}{\ln\left(\frac{h_1}{z_0}\right)}$$

   Where v_1 (m/s) is the wind speed at the measured height, h_1(m), and v_2 (m/s) is the calculated wind speed at the measured hub height, h_2(m). z_0(m) represents the estimated roughness of the land by the wind speed measurement tool and was assumed to be 0.0024m, "open terrain with smooth surface". (Commin, et al., 2017) (Swiss Wind Power Data, 2020)
4. The year of commissioning was included for each site, to allow for an annual degradation rate to be included for the baseline model.
5. The annual outputs calculated for each of the sites were then assessed against historical data found for or provide by 7 out of the 10 sites, section 3.6.

By following the above procedure, it allowed the modelling of the wind resources to be conducted from a single input wind speed variable. This assumes the wind to be constant across the island during each hour. Whilst it is recognised that this will not be the exact case, the assumption here is deemed suitable to ensure that the variable nature of the wind turbines is reflected in the analysis and the model does not over emphasize the benefits from wind power production. The power output at each site will be highly correlated across the region, but likely not 100%. As the region has a high proportion of wind resources (that is likely to grow in the coming years), this is an area that could be studied further if reliable wind speed data were made available from the different sites.

The wind speed variable can be then forecasted in time using stochastic sampling. As the Met office datasets provided ten years of hourly wind speeds, these are used and can be selected randomly when forecasting future scenarios. Therefore, complex wind patterns that occur across time periods from diurnal to annual can be taken into consideration. The final stochastic modelling process is further explained in section 4.1.2.

3.4.3 Hydro Power

There are two hydro power stations on Lewis and Harris. Both were included in the model as dispatchable generation, with maximum annual capacity factors of 35% due to historical generation figures. (Department for BEIS, 2021)

Table 10 Hydro Power Stations

Name	Capacity (MW)	Location (node)	Year built
Gisla	0.75	Gisla 11kV	-
Chliostair	1.2	Harris 33kV	1960

3.4.4 Solar PV

The majority of the Solar PV installed on the island is in the form of small-scale distributed systems. The following table details the Solar PV capacity per demand region in the model. This was calculated from the OFGEM feed-in-tariff online database. (OFGEM, 2021)

Table 11 Distributed Solar PV Capacity, per Demand Region

Demand Region	Installed Capacity (MW)
Stornoway	0.37
Northeast Lewis	0.03
Northwest Lewis	0.06
Southwest Lewis	0.06
South Lewis	0.03
Harris	0.06

The power output from the Solar PV on the island was estimated using the European Commission's online tool PVGIS. The online interactive tool uses a typical meteorological year methodology, TMY, taking 'typical' months from the years 2007-2016 to create a single annual profile. (European Commission, 2021)

It was assumed that all panels would have the same hourly profile, based on co-ordinates at the centre of Lewis and Harris (58.086, -6.635). The optimal slope (40 deg.) and azimuth (3 deg.) were selected, alongside crystalline silicon panels.

The annual hourly profile for a rate panel of $1kW_p$ is shown in Figure 18. The annual capacity factor was calculated as 10.21%.

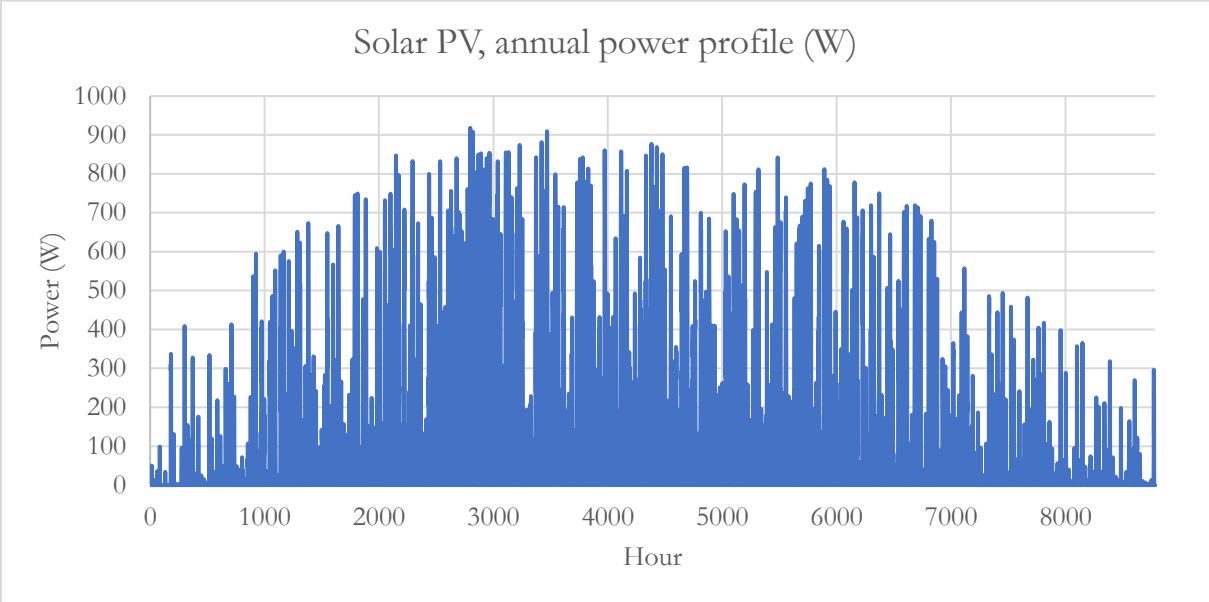

Figure 18 Annual Profile for 1kWp Solar PV panel

3.5 Imported/Exported Electricity

Electricity bought and sold to the mainland was assumed to follow the UK day-ahead market prices for 2019. The dataset available from Nordpool was deemed the best available to represent mainland hourly price, with an average of 42.94 £/MWh, a (extremely rare) high of 276.51 £/MWh and a low of -2.84 £/MWh. (Nordpool, 2021) The price is shown graphically in the annex, section 9.3.

Additionally, electricity supplied to the island was assumed to have an average emission factor in line with the 2019 BEIS Emissions projections. The factor falls from 160 to just below 80 $kgCO_2e$/MWh from 2019 to 2035, respectively. (Department for BEIS, 2019)

3.6 Expansion Candidates

In the scenario analysis, the following technologies were included as possible expansion candidates, and optimised within each simulation.

- Onshore wind
- Solar PV
- Battery Energy Storage System (BESS)

The above technologies were chosen due to their technological maturity, as well as their common prevalence in previous literature studying future renewable systems. It was decided that technologies without proven commercial viability would be excluded from the options, to avoid too much speculation within the technical assumptions and economic analysis. However, there are many additional technologies that may be of interest to the Western Isles system, some of which came up in the background research stage of the project and were discussed in the section 3.3.1.

The following table describe the technical and economic information for these technologies, including capital expenditure (CAPEX) and operating and maintenance (O&M) costs. Solar and wind technologies have been characterised by rapidly falling costs in recent years. These trends are expected to continue, especially with regards to capital costs, reflect in table Table 12. The cost estimates were adapted from numerous sources, as well as compared to previous data collection on renewable project costs in the UK. (GOV.UK, 2020c) (NREL, 2021) (NREL, 2019) (IRENA, 2019) (IRENA, 2018) (Pietzcker, et al., 2021)

Table 12 CAPEX and O&M data for onshore wind, solar PV, and BESS

Technology	Capex (£/kW, £/kWh for BESS)			Fixed O&M (£/kW/year)
	2020	2035	Projected annual decrease (%)	
Onshore Wind	1257	1065	1.1	40
Solar PV	703	357	4.4	10
BESS[6]	300	101	7	-

Fuel costs, or variable O&Ms (£/kWh), were assumed to be zero for all technologies. Degradation over time is experienced by both solar PV and onshore wind. This was included in the technical inputs as 1.6% and 0.9% per year, respectively. (Staffell, et al., 2014) Additional technical parameters for batteries include charging and discharging efficiency, assumed to be 95% and 99%, respectively.

[6] For BESS specific CAPEX, it is acknowledged that final costs will be dependent on power-to-energy ratio for the system, with high ratios resulting in higher cost. For the thesis, the price was not split out into these respective parts.

3.7 Model Validation

The baseline model was validated against various available data sources. This was done using the PLEXOS ST Schedule optimiser, running annual simulations at hourly intervals for the years 2019/20

Table 13 shows estimated annual generation (GWh), annual capacity factors (%) and variation from historical data (%), where available, for the different renewable generation sites on the island, for 2019. These were compared with historical data provided from the following sources:

- Production data for Galson, Beinn Ghrideag and Creed Business Park (hourly or 10-minute resolution datafiles provided by contacts for different sites).
- Renewable Obligation, RO, database providing monthly data for Arnish Moor, Tolsta, Monan and Pentland Road. (OFGEM, 2020)
- Annual capacity factors for remaining Solar, wind, and hydro sites. (Department for BEIS, 2020a)

Note that the figures for estimated annual generation (GWh) and annual capacity factors (%) have been removed from the wind parks due to confidentiality.

Table 13 Renewable generation capacity factors from PLEXOS ST schedule, 2019

Generator	Type	Generation (GWh)	Capacity Factor (%)	Difference from actual Capacity Factor (%)
Galson	Wind	-	-	0.03%
Arnish Moor	Wind	-	-	3.45%
Horshader CWF	Wind	-	-	-
Tolsta CWF	Wind	-	-	0.87%
Horgabost	Wind	-	-	-
Monan CWF	Wind	-	-	1.71%
Beinn Ghrideag CWF	Wind	-	-	2.71%
Bridge Cottages	Wind	-	-	-
Creed Business Park	Wind	-	-	-0.66%
Pentland Road	Wind	-	-	-2.30%
Distributed Solar PV	Solar	0.56	10.21	-0.94%
Distributed Wind	Wind	1.04	30.3	-
Gisla	Hydro	2.27	34.51	-0.58%
Loch Chliostair	Hydro	3.75	35.64	0.55%
Anaerobic Digestion	AD	0.34	19.64	0.83%

Capacity factors vary across the different island locations. The process used to estimate wind power production for each of the sources provided results that also vary in terms of their accuracy, with the least accurate estimates, Arnish Moor and Beinn Ghridaeag, over-estimating production by 3.45% and 2.71%, respectively. Historical annual production values were also seen to vary, by up to 7%, for the different sites from one year to the next. This highlights the variable nature of wind. Although, when considering all combined wind assets, if the different sites were aggregated for the island the average 2019 capacity factor (36.05%) tended towards the aggregate value found via BIES sources for the wider Western Isles region (35.06%). (Department for BEIS, 2021)

The energy flows in the lines representing the distribution grid were also investigated. Figure 19 shows the energy flow (MW) in the subsea cable line for 2020. The cable capacity is assumed to be zero during three period of the year: (a) during two weeks in June, and one additional week in October when annual maintenance is carried out on the line, and (b) from 16th October onwards to represent the failure in the line that has occurred. The cable's rating is reach throughout the year, in terms of both importing electricity to meet demand, mainly during winter months, and when trying to export excess renewable generation, throughout the year. This confirms the major constraints in the current system. (Xero Energy , 2017)

Figure 20 shows the diesel generator output for the year. The model confirms that even with the old subsea cable connection and on island renewable generation the diesel generator is occasionally relied upon to meet peak demand during the winter months. The diesel power station is also required during the summer period when the cable is out of action for maintenance. (Element Energy, 2014) Finally, the impact of the cable failure is clear as the island becomes reliant upon the diesel generation for meeting most of the electricity demand.

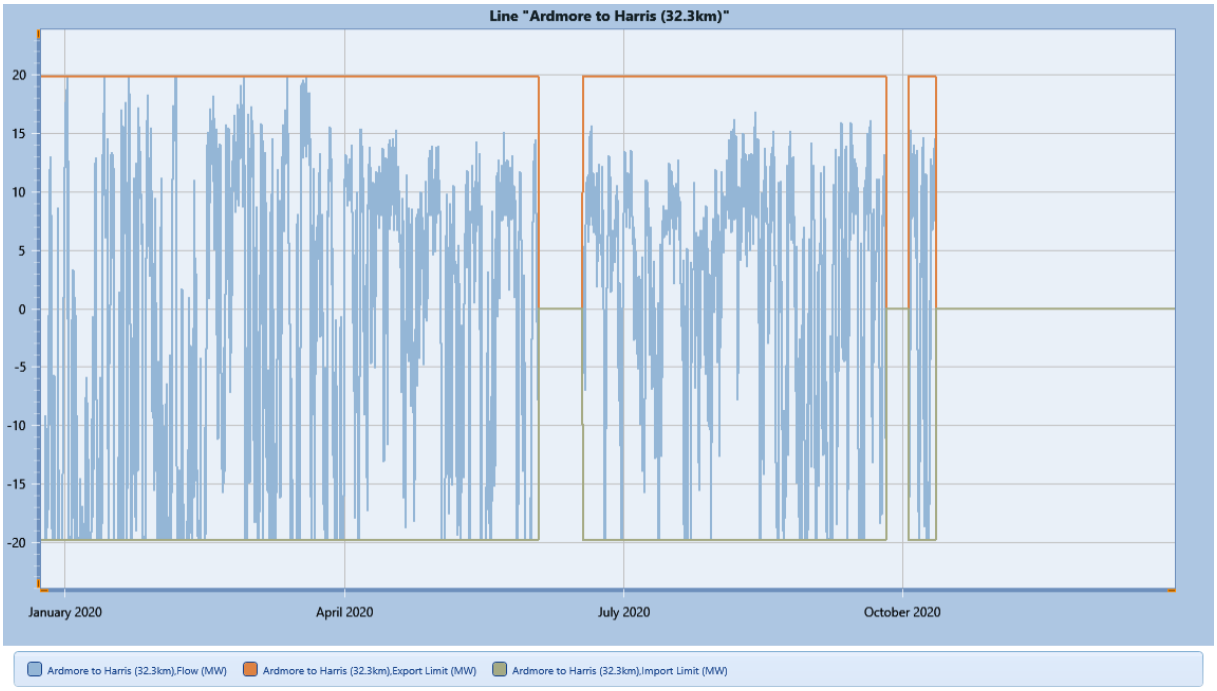

Figure 19 Subsea cable energy flow (MW), with import/export limits (MW)

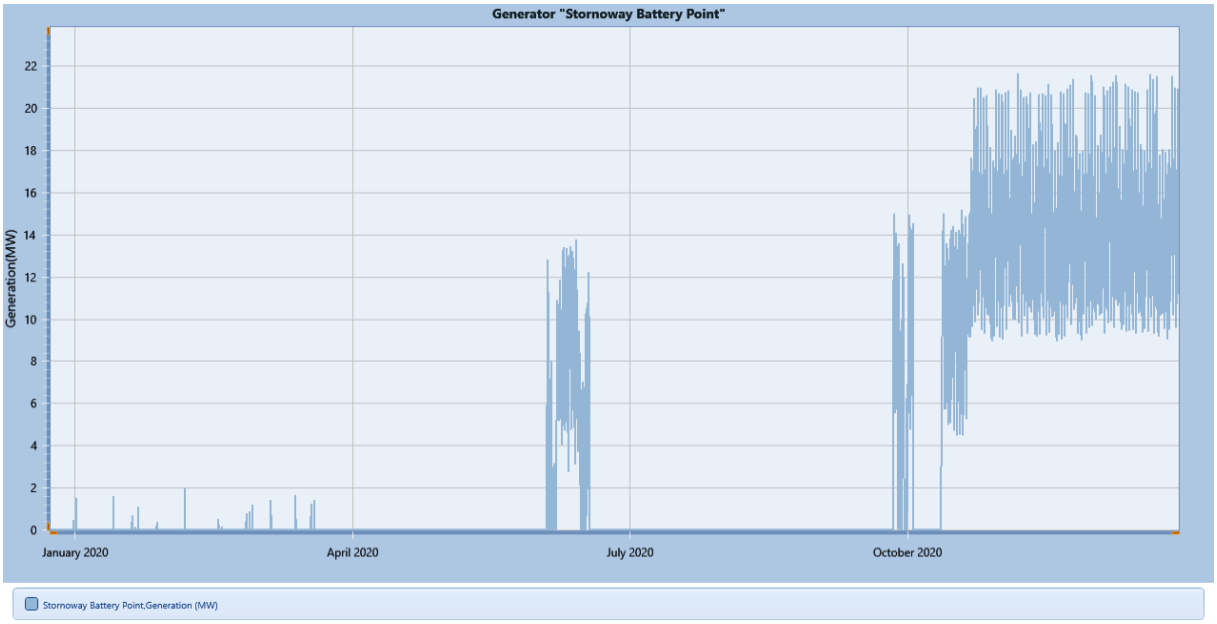

Figure 20 Diesel Generator Power Output 2020 (MW)

4 Scenario Analysis

4.1 Analysis Aims

Scenario analysis can be used to investigate different possible pathways for the island. This technique allows for differentiating between the alternative pathways, gaining potential insight via any differing results. Here, the aim was to focus on the future local renewable potential in each scenario, as well as imports and exports to the mainland.

The additional electricity demand from HPs and EVs will be assumed for all scenarios, with the specific impacts from the new subsea cable connection and potential closure of the diesel power station investigated.

PLEXOS LT Plan was used to provide a least-cost capacity expansion plan in terms of new wind, solar PV, and BESS resources for each specific scenario, with a timeframe to 2035. For more in-depth analysis the ST Schedule can then be used to look at specific future years and attempt to gain further insight into the future energy system.

4.1.1 LT Plan Settings

Capacity expansion takes into consideration two main types of cost: capital costs (CAPEX) and operation costs (OPEX). The objective of each scenario simulation if to find a solution that provides the lowest NPV. A simplified graph of this trade-off is shown in Figure 21. The objective function is formulated as a mixed-integer problem (MIP).

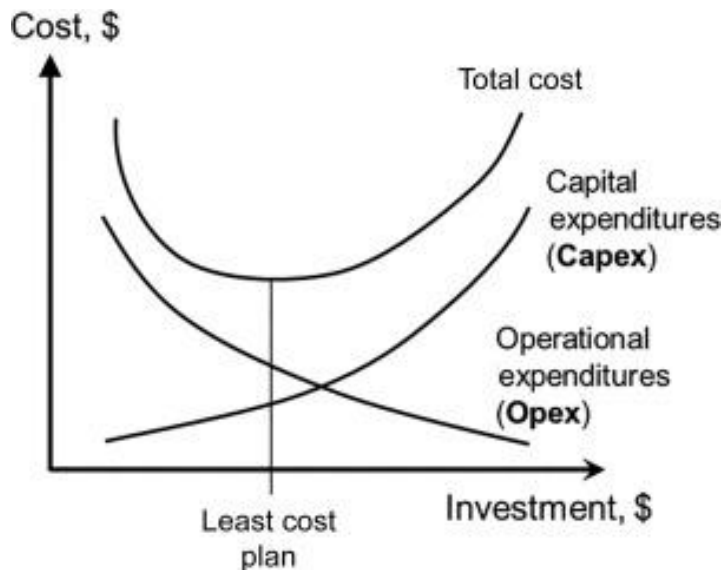

Figure 21 Simplified optimisation trade-off in long term expansion planning, (Ferrari, 2021)

For all scenarios, the Weighted Average Cost of Capital (WACC) was assumed to be 6%, along with an identical discount factor, with the last year of the simulation assumed to run to perpetuity. The above rate was chosen as the average UK WACC for onshore wind found in previous literature, as well as being like average EU solar projects. (Steffen, 2020)

Solving optimisation models across long time horizons at high temporal resolution can require large amounts of computational power. During the thesis this was constrained in terms of memory available (RAM) and actual time taken to run each simulation. To reduce this, whilst providing accurate results, the following settings were used.

The CPLEX 12.10.0.0 solver was used, with the relative gap was set at 0.01%. The relative gap sets the margin between the final solution and the optimal solution, to help reduce computational demand and therefore run times. Completing the simulation as a single step proved to be demanding in terms of memory due to the high temporal resolution and additional stochastics. Therefore, the step horizon size was set at 5 years, with a 2-year overlap included in each step to help improve the optimality of the final solution.

Due to the modelling of renewable generators and batteries, using as high a temporal resolution as possible was important to gain accurate results. Within the LT Plan simulations there are different chronology setting available: partial, fitted and sampled. Each one differs in terms of how the step horizon is divided up into step functions (years, months, weeks, or days) which are then divided into blocks. Each block is then fitted with a load duration curve (LDC). Partial offers the most simplified optimisation, where chronology is only maintained between LDCs, whereas sampled uses statistical methods to reduce the horizon to a user defined number of similar periods which are then used to represent the whole step horizon and thus a higher time resolution can be used. All three methods were tested and the most suitable was deemed to be the fitted setting. This keeps the step chronology both between blocks and within them. Furthermore, the blocks are fitted to each step function using an on/off peak bias to increase the granularity during peak hours when accuracy is often most critical. For the final simulations 56 blocks were fitted to weekly step horizons. Finally, the value of lost load was set at 11 £/kWh, in line with lost load valuations for Western European countries. (Cambridge Economic Policy Associates Ltd, 2018)

4.1.2 Stochastic Modelling for Wind Profiles

Stochastic modelling is a tool that can be utilised for incorporating uncertainty into an energy modelling process. This can be particularly useful when modelling VRE sources. Using variables in PLEXOS it is possible for any model input to be included as a stochastic property. For this study, stochastic variables were used only for the wind speed inputs. This was chosen due to the high levels of wind present in the energy system as well as the more complex nature of the wind variations compared to solar irradiation.

The wind power produced by the turbines in the model is a function of the wind speed, via the relevant power curve. As such, the uncertainty surrounding the wind speed patterns could be included directly as a stochastic variable. The 10 years of historical wind speed data were each included as separate annual samples. The model then selected entire year samples at random when forecasting the future LT Plan. It is possible to run multiple samples for each year, with the final optimisation incorporating all sample runs. This approach was used during earlier optimisation runs; however, it caused the run time to increase considerably, and the additional time was excessive. For the final runs which the results are based on only a single sample was used for each year. The random seed generator was set identical for each scenario to ensure all scenarios included the same pattern of annual hourly wind speed sets.

During the modelling process the EV demand (km) and charging station share (%) were identified as input parameter with possible high levels of uncertainty and thus incorporating stochastics into these input variables was identified as possible future work.

4.2 Scenarios

Scenarios 1a, 1b, 2a, and 2b investigate the subsea cable connection and closure of the diesel power station. For all scenarios, the uptake of HPs and EVs was assumed to be the same. Some of the results from these scenarios are discussed in 5.1 and in 5.2 a comparison across the four scenarios is made.

Scenario 3a was then run to compare the inclusion of smart charging, V1G, on the system. The results here are briefly discussed in section 5.3.

Finally, sensitivity analysis was run on some of the initial scenarios, with regards to the mainland electricity price, section 3.5, and the results and implications of this are discussed in section 5.4.

The different scenarios are described further below.

Scenario 1a – Baseline

Scenario 1a investigate the baseline case, where the currently failed subsea cable is replaced with a 30MW rated replacement, as per SSE's current proposal. (SSEN, 2020) The scenario assumed the following uptake of HPs and EVs, as described in previous sections.

Table 14 displays the number of HPs and EVs added to each demand region by 2035. The addition per year is assumed linear in both cases. The number of HPs was calculated assuming that all remaining coal and oil central heating systems are replaced by heat pumps. (National Records of Scotland, 2017) It is noticeable that Stornoway has a smaller number of additional HPs, in comparison to its total number of homes. This is due to the gas grid in Stornoway which is currently being investigated for the potential of fuel switching to 100% hydrogen. The grid feeds around 1700 homes, which should be taken into consideration if the hydrogen plan was unsuccessful, and electrification of heating was also seen here. The number of EVs was calculated assuming that 60% of domestic vehicles are electric by 2035.

Table 14 Number of heat pumps and EVs installed to 2035.

Demand Region	Heat Pump by 2035 (no.)	Electric Vehicles by 2035 (no.)
Stornoway	1645	2733
Northeast Lewis	614	814
Northwest Lewis	727	762
Southwest Lewis	592	691
South Lewis	485	566
Harris	459	556
Total	4522	6122

Assuming the above levels of HP and EV adoption, and the methodology detailed in sections 3.3.5 and 3.3.6, the additional demand from HPs and EVs by 2035 would be circa. 29GWh and 18GWh, respectively. The direct emission reduction from these assumptions (i.e., from less oil consumption in home boilers and from less diesel/petrol consumption by vehicles) are not included in the analysis results and are the same for all scenarios.

Scenario 1b – Baseline + No Diesel 2030

Scenario 1b is like scenario 1a, although with the diesel power station removed from the energy production mix from 2030, after RIIO2. With the new cable installed the need for the diesel generator should fall, however its use during periods of cable maintenance and possible need during winter peaks will need to be replaced.

Scenario 2a – Additional Connection

Scenario 2a is, again, as per scenario 1, although the connection to the mainland will be replaced by a 60MW connection, increasing the subsea connection whilst remaining within the 33kV voltage level, and therefore distribution, remit. This additional cable capacity was suggested by OFGEM to the local community and could provide a greater potential route to market for the generators. Whilst this scenario does not aim to provide a conclusive answer to whether the second cable should be installed, its potential impact on the system is investigated.

Scenario 2b – Additional Connection + No Diesel 2030

Scenario 2b is like scenario 2a, with the diesel power station removed from the energy production mix from 2030, after RIIO2. The scenario was carried out in part to help confirm why any additional capacity was occurring between the four main scenarios, i.e., due to the connection vs the removal of the diesel power station.

Scenario 3a – Baseline – New Cable + V1G

Scenario 3 is identical to 1a, apart from deferred charging was allowed for EVs, for up to 6 hours.

4.3 Sensitivity Analysis

Sensitivity analysis is a useful tool to determine the impact that input parameters have on the results. Due to time constraints this was only briefly completed, with additional simulations carried out for new electricity price inputs, based on 2020 data. It was found that some of the results were extremely sensitive to this input and, ideally, further analysis would be carried out to better represent the income available for any additional wind and solar projects on the island. The implications here is further discussed in section 5.4.

The potential use of additional sensitivity analysis is also discussed in section 5, with regards to better understanding the impact from the RES CAPEX input data.

5 Results and Discussion

The analysis was conducted for all scenarios first assuming that no smart charging was allowed. Some of the main results of the first four scenarios are detailed and discussed in section 5.1 and in section 5.2 a comparison is made across the four scenarios.

Section 5.3 then briefly discusses the partial results from the scenario that included V1G. This allows for some insight into the potential that smart charging may bring to the system.

Some of the scenarios were then re-run using 2020 mainland electricity prices instead of 2019. Section 5.4 then discusses the results and implications of this.

5.1 Scenario Results

Scenario 1a – Baseline – New Cable

Figure 22 (left) shows the new capacity added each year in the baseline scenario. There is a relatively large amount of new wind capacity added in the first year of the simulation, 2022. This is likely due to the additional capacity that the new cable has, compared to the old connection. There is then a small amount of additional wind added in the subsequent years. As electricity demand on the island increases in the scenario this is likely causing the additional capacity each year. The final mix, shown in Figure 22 (right) includes both new wind and solar PV capacity, as well as BESS. It is noticeable that both the solar PV and BESS are added at the same time, in the last year of the simulation. Sensitivity analysis of the CAPEX for both technologies may help to determine the leading cause of the expansion here, however this is discussed further in relation to scenario 1b results.

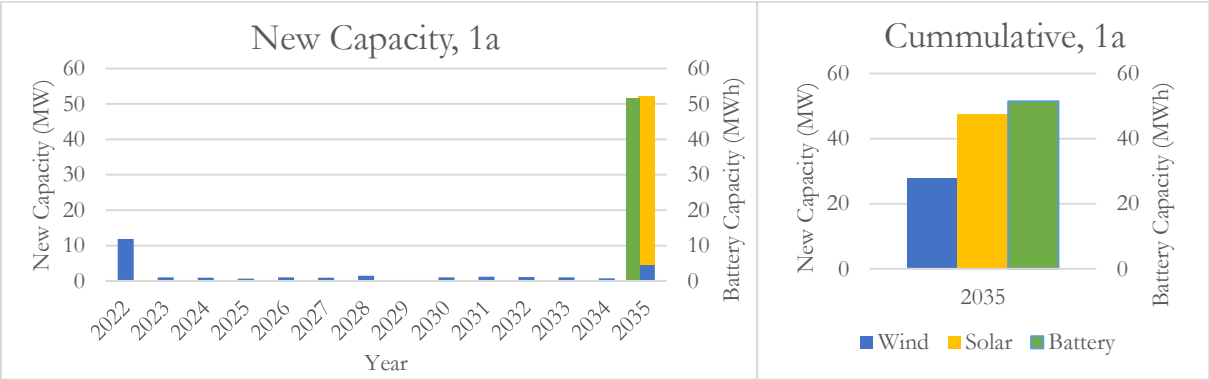

Figure 22 Scenario 1a (left) New additional capacity, (right) cumulative capacity (MW, MWh).

The on-island generation is then shown for each year of the analysis, in Figure 23. Wind generation continues to dominate the island's generation until 2035 when the solar PV and BESS is implemented. The diesel power station is still used in scenario 1a in 2035, although annual consumption drops by almost two thirds from 2034 to 2035. This is better displayed in Figure 25, shown further below.

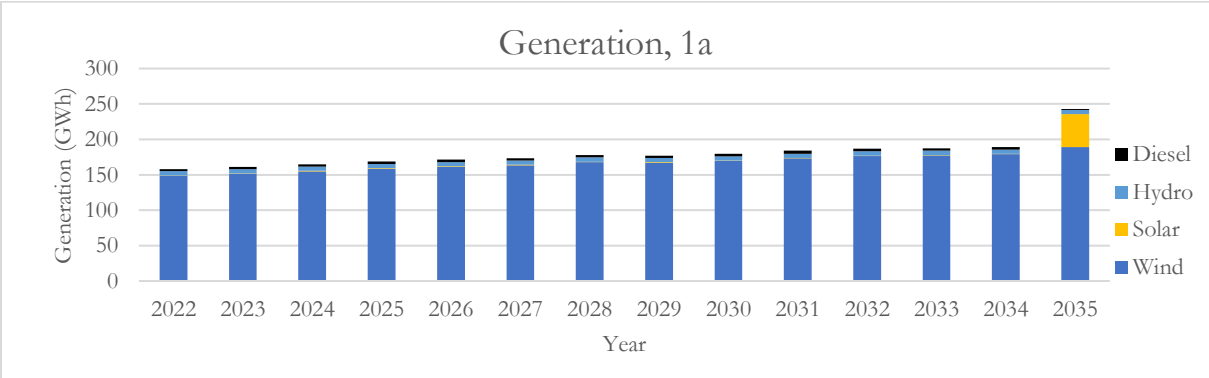

Figure 23 Scenario 1a Annual local generation (GWh).

Imports and exports to the mainland are displayed in Figure 24. It is noticeable that both import and export trends increase in the years up to 2034. In the case of imports this is more pronounced and highlights that even with additional wind resources being added the increase in electricity demand from HPs and EVs still results in more electricity being supplied by the mainland. It is not until the BESS is included in 2035 that we see a drop in imports from one year to the next, with a noticeable increase in exports also occurring.

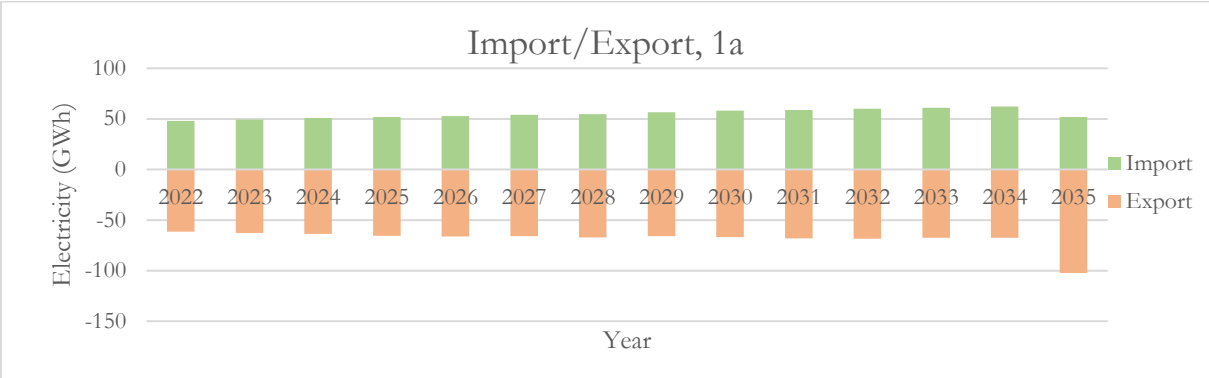

Figure 24 Scenario 1a Annual Import/Export to the mainland (GWh)

Scenario 1a emissions are shown in Figure 25. It should be noted that these are only the emissions from the modelled electricity system in PLEXOS, and emissions from RES are assumed to be zero. The emissions are relatively constant throughout the simulation, with a slight downtrend. It is not until the BESS is installed, in 2035, that there are major reductions in system emissions. The BESS installation, alongside additional solar PV, appears to cause a considerable reduction in required production from the local diesel generator from 2034 to 2035, however does not completely remove the need for diesel production.

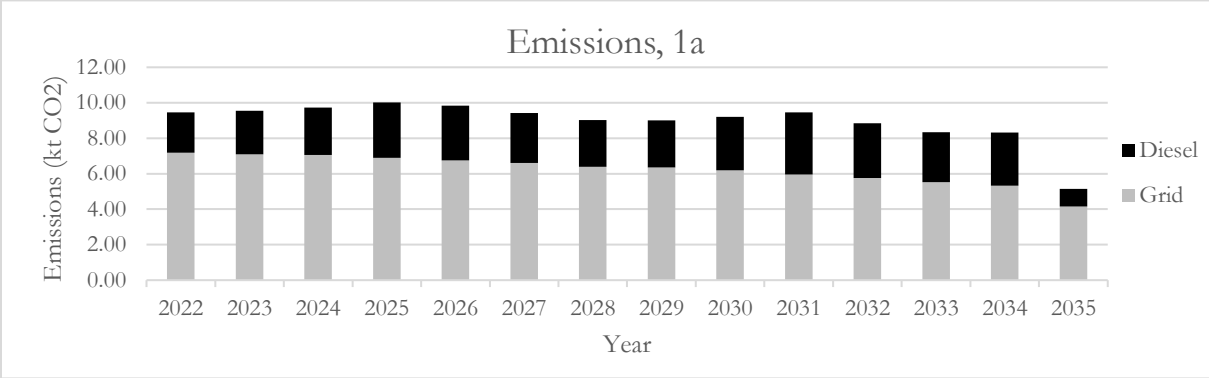

Figure 25 Scenario 1a Annual Emissions (kt CO2)

Scenario 1b – New Cable + No Diesel 2030

Figure 26 (left), below, shows the expansion plan for scenario 1b. Again, the initial additional wind capacity due to the new cable can be seen in 2022. The main change in scenario 1b can be seen in 2030 as the removal of the diesel power station from the system results in a major build in the same year.

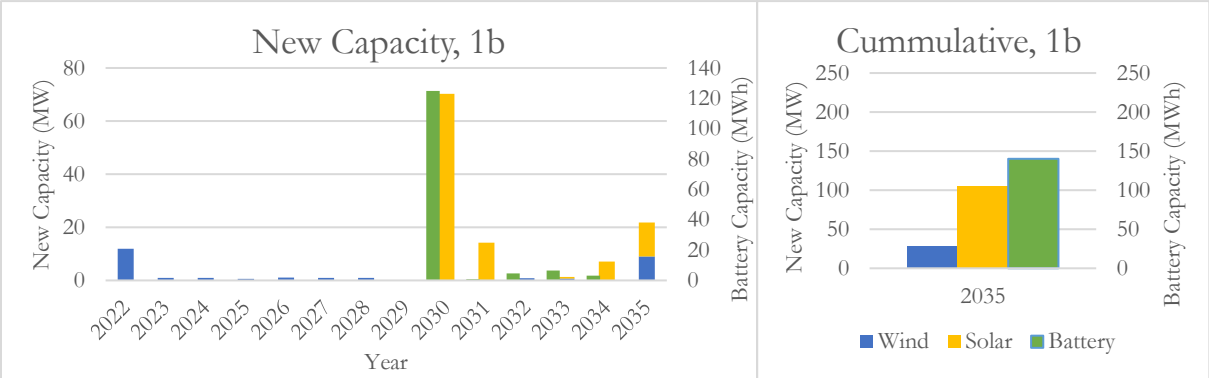

Figure 26 Scenario 1b (left) New additional capacity, (right) cumulative capacity (MW, MWh).

It is noticeable that the BESS installed in 2030, 125MWh, is considerably higher than that installed in the entirety of scenario 1a, 51.5MWh. The earlier addition of BESS accelerates the transition and enables the addition of solar PV both earlier, in 2030, and to greater levels.

Scenario 2a – New Cable + No Diesel 2030

Finally, Figure 27, below, displays the capacity expansion for scenario 2a. The results are very similar to 1a, however the wind capacity expansion in 2022 is far higher in scenario 2a, due to the larger cable connection.

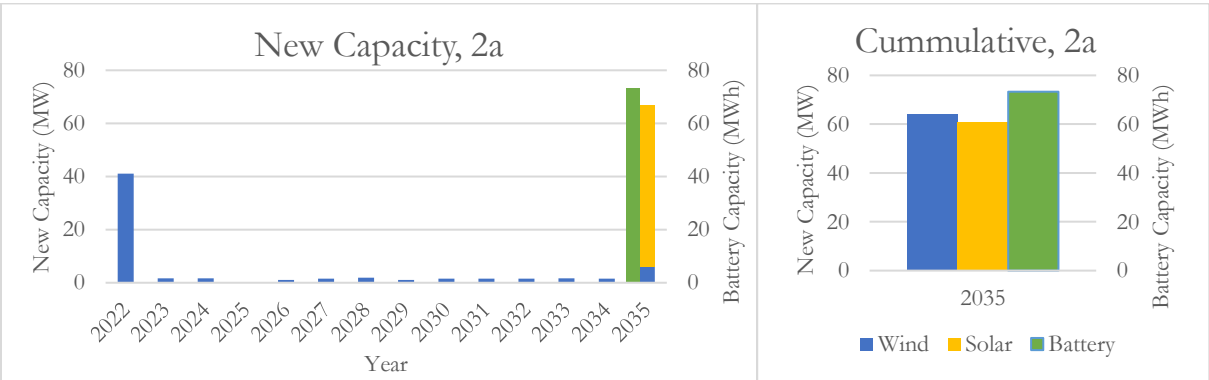

Figure 27 Scenario 2a (left) New additional capacity, (right) cumulative capacity (MW, MWh).

5.2 Comparison of Main Results

The following discussion will focus on comparing scenarios 1a, 1b, 2a and 2b.

The link between additional wind capacity and the cable connection capacity is highlighted clearly when comparing both scenarios 1a and b with 2a and b. Whilst the new cable connection, 30MW, appears to allow for some additional wind capacity, 11.9MW, onto the grid in the first year of the optimisation, the additional connection scenarios both include new wind capacity of 41MW in the first year; Figure 28.

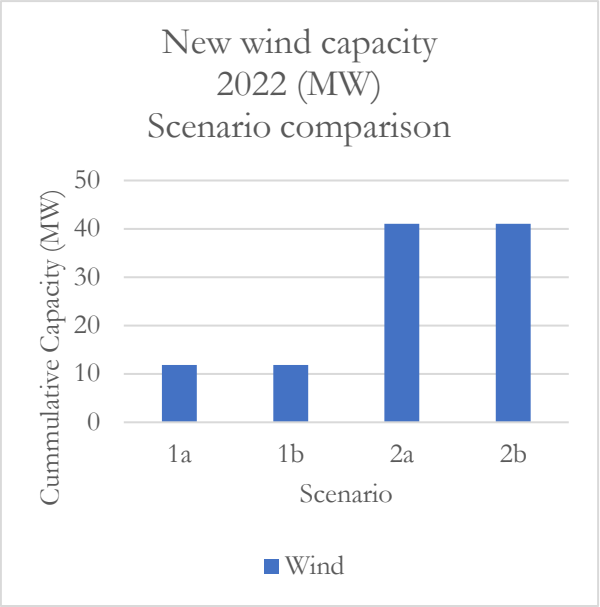

Figure 28 Scenario results comparison. New wind capacity 2022

This itself highlights the importance of the mainland connection if the island is to become a major exporter to the mainland in the coming years. For the initial years of the simulations the exports grow 234.1% from scenario 1a/b to scenarios 2a/b, Figure 29.

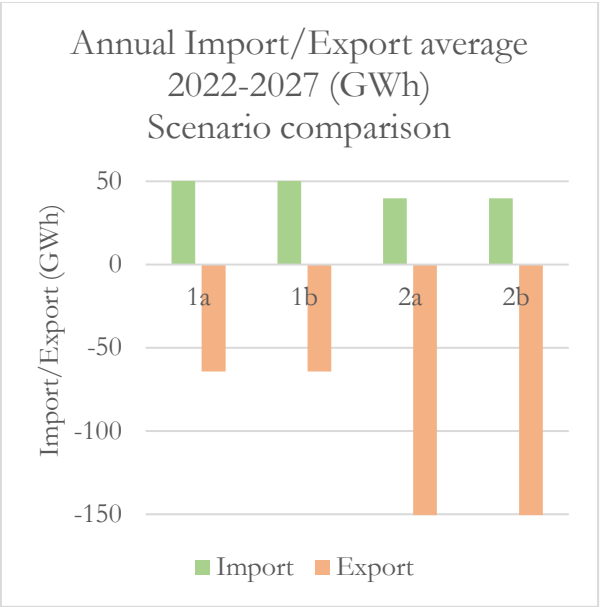

Figure 29 Scenario results comparison. Imports/Exports, 2022-2027

If the HVDC cable project is not successful, the additional capacity between Ardmore and Harris would become even more important in providing opportunity for island generation to sell electricity on the mainland. Whilst the exports grow with the additional on island wind resources, the imports also fall, however to a far less significant degree. Again, for the initial years of the simulations the imports fall by 22.1% from scenario 1a/b to scenarios 2a/b. This highlights that whilst new wind capacity can have a major impact in terms of exports, additional wind capacity alone still leaves the island heavily reliant on the mainland for electricity throughout the year.

When considering the final cumulative additional capacities of all scenarios, Figure 30, a major change in the island's generation capacity comes via the introduction of BESS, as well as a major increase in solar PV compared to the current level of <1MW. The expansions of solar, from a more general perspective, is not unexpected by itself. The recent International Energy Agency (IEA) World Energy Outlook 2020 centred in on the future dominance of solar PV, highlighting the rapidly falling capital costs (20-50% lower than previous IEA publications), as well as forecasting solar to become the number one electricity capacity in Europe within 5 years and by 2040 the global solar output would be 43% higher than their previous 2018 prediction. (IEA, 2020)

Looking closer into the results, the cause of the solar expansion is not as clear as the additional wind capacity, however there are several points of interest that do appear in the results.

Firstly, even in the scenarios without the diesel closure BESS and additional solar PV is still present in the final system, along with the introduction of additional PV at a large scale. To clarify what is causing this, additional sensitivity analysis could provide insight. For example, one possible explanation may be that the BESS price is the driver for making solar PV economic. If this were the case, then decreasing the BESS cost at a faster rate than the current estimation may lead to the expansion of solar PV in earlier years that 2035 for scenarios 1a and 2a. This situation is itself worth considering, as some industry reports have forecast falling costs of batteries at a far quicker rate than was used in this work. (Bloomberg, 2020).

When comparing scenarios 1a and 2a against each other there is a 13.2MW (27.8%) increase in the final solar capacity added to the system. This would indicate that the extra cable capacity can provide benefit in the future in the future as RES costs are decrease further, on top of the current benefit that can be realised through additional wind resources.

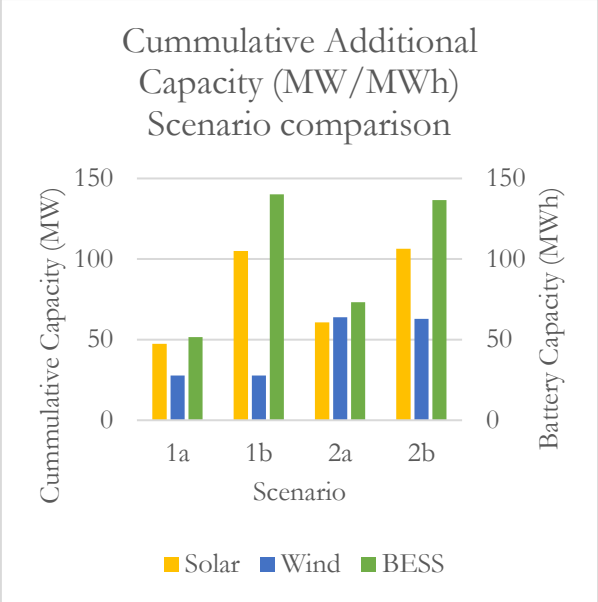

Figure 30 Scenario results comparison. Cumulative added capacity (MW/MWh)

When comparing scenarios 1b with 1a and 2b with 2a the additional solar capacity increases dramatically, by 221% and 175%, respectively. The capacity of the installed BESS also increases, at even higher proportions. Scenarios 1b and 2b assume that the diesel generator is removed from the energy production mix from 2030 and it is clear from Figure 26(left) that in response to this the least-cost solution includes the installed combination of both BESS and PV. It is interesting that additional wind resources are not added at this point, however, it is likely due to the already high proportion of wind in the island system already and thus the addition of solar PV may compliment the already installed wind capacity. In both scenarios (1b,2b) the BESS added in year 2030 is very similar, 125 and 127 MWh, respectively. The addition of battery resources to replace the dispatchable diesel power could be compared to alternative possibilities, such as the conversion of the diesel turbines to a low-carbon fuel source. Furthermore, the

batteries themselves essentially represent load shifting to allow the variable supply to meet demand, during the hours when the cable is not in use. The possible use of more flexible demand technologies could be investigated to help limit the size of the necessary battery, thus limiting the CAPEX of the installation.

If falling batteries prices are to lead to the technology become economically viable, as in scenarios 1a and 2a, then the future need for the diesel power station will fall further, by 66.6% and 78.8%, respectively from 2034 to 2035. However, in both scenarios 1a and 2a the diesel station was still used in 2035, albeit at a far smaller output. The forced removal of the diesel generator, within scenarios 1b and 2b, from the system represents an accelerated transition. The CAPEX of any BESS project in 2030 will be higher than in 2035, 43.7% higher per MWh when using the forecasted prices in Table 12. However, both accelerated scenarios produce emissions reduction over the 14-year period of 12.4% and 13.3%, respectively, as shown in Figure 31. If emissions are considered only during the five years from 2030-2035 (when the removal of the diesel power comes into effect) then this emission reduction impact is heightened to 31.8% and 33.1%, respectively. Furthermore, the 'accelerated' scenarios result in earlier and greater levels of final additional solar PV. The additional cost of the earlier introduction of BESS will be offset against the diesel fuel, and operating and maintenance costs, alongside emission taxes. The input data for the diesel power station was estimated from previous studies and literature. Greater insight here would provide a more accurate cost-benefit analysis for removal of diesel power from the electricity mix. The diesel fuel costs for the power station are themselves a factor that should be considered further, as the island is required to pay additional transport costs in comparison so mainland sources. This alongside the new UK emission tax represent possible future price risks that could also be alleviated by the consideration of a battery and further on-island RES.

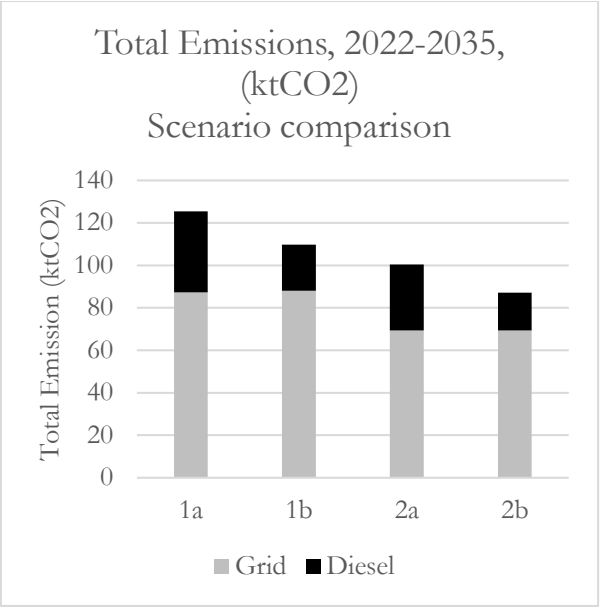

Figure 31 Scenario results comparison. Emissions (ktCO2)

Additional opportunities for RES in the coming years appear limited out with the major decisions surrounding the new cable and the diesel power station, i.e., years 2023-2034 in Figure 22. The results do indicate that a small additional wind capacity increase is optimal, possibly due to the increasing HPs and EVs in the system as well as the degradation of the current assets. However, this amount is smaller than any capacity increases due to the interconnection limit or removal of the diesel power generator. Furthermore, in scenario 1a the electricity imported to the island increases year-on-year until the BESS is installed, indicating that additional electrification will likely lead to further imports from the mainland without the additional of greater energy storage technology. This highlights that on island generation expansion is likely to be limited in terms of expansion without additional interconnection to the mainland or waiting for the falling price of RES and BESS, especially when compared to the sizeable local authority

targets. Due to the particularly favourable wind conditions in the region, if the new interconnector is to remain at the 30MW and the HVDC link is not approved then alternative uses for the wind power could be further investigated. Hydrogen production was identified in the background research as a focus at both local and governmental level and as such would be a possible next step for future modelling work. Another alternative would be to use the power to produce heat which can be stored via thermal energy storage. This, coupled with BESS, would provide further flexibility to the island's energy system.

5.3 Additional V1G Results

Scenario 1a was repeated, with the addition of deferrable load, for up to a 6-hour period. Smart charging is likely to play a key role in future EV systems when looking to both academic literature and industry guidance. (Taibi, et al., 2018) (OFGEM, 2018)

This was completed in the latter stages of the thesis and therefore the full results are not included. However, initial comparison with scenario 1a would indicate that smart charging may help integrate further wind resources on the island, with an additional 12.7MW installed by 2035, Figure 32, below. Further work is required here to include the additional uncertainties that come with the V1G concept, such as extra required infrastructure and how customers will be incentivised to allow their EVs to be controlled by a 3rd party.

Scenario 3a – New Cable + Smart Charging

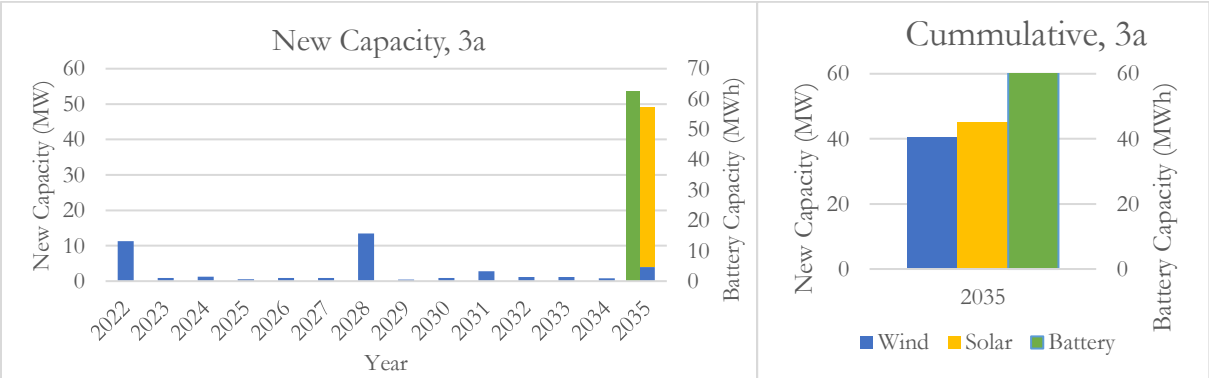

Figure 32 Scenario 3a. (left) New additional capacity, (right) Cumulative capacity (MW, MWh).

5.4 Electricity Price Sensitivity

The dataset used to represent mainland import and export prices was from 2019, as mentioned previously in section 3.5. These day-ahead prices were publicly available from Nordpool. (Nordpool, 2021) The hourly dataset included peak and off-peak patterns that are an important characteristic for electricity price, as well as representing the volatility that is commonplace in electricity prices today. However, the use of the single dataset represents a major limitation within the study as forecasting electricity prices to 2035 from this single year will lead to likely inaccuracies, especially the future years.

In addition to the 2019 data, 2020 hourly data also became available during the duration of the thesis. The average price dropped from 42.94 £/MWh in 2019 to £35.19 in 2020, an average reduction of 18%. Furthermore, the volatility[7] increased by 88.7%, with the high for the year 2020 reaching 350£/MWh and consistent negative prices, reaching as low as -38.8£/MWh. The 2020 prices are displayed graphically in the annex, section 9.3. The 2020 dataset is also likely to include some of the impacts that occurred due to the Covid-19 pandemic, as lifestyle patterns were drastically changed due to national lockdowns. This will undoubtably have had an impact on the electricity prices, however this trend of lower average costs

[7] Measured by the variance of the two hourly datasets.

coupled with higher volatility may well continue in the future, especially due to the extremely large amount of VRES being installed at a national level. As such the 2020 dataset was used to re-run some of the initial scenarios.

The partial results for this are shown in Figure 33, with the capacity expansion shown for scenario 1(a) using 2020 electricity prices.

The changes are clear, as the additional generation capacity added to the system falls to zero until the year 2035, when the BESS is installed. A similar pattern was seen in alternative scenarios, with no build out of new wind capacity installed until the BESS is present in the system. In the case where the diesel power station is removed in 2030 the resulting system still responds with an earlier installation of BESS and Solar PV in the same year.

This shows the results are very sensitive to the electricity price input used. Especially, any new wind installations. It is important to consider that the lower, more volatile, prices impact both the added wind capacity due to the larger cable and the new capacity added in future years that was likely due to the growing electricity demand on the island. Local generation in this case will stall on the island, as shown in Figure 34, which in turn results in fewer exports to the mainland and greater reliance on imports.

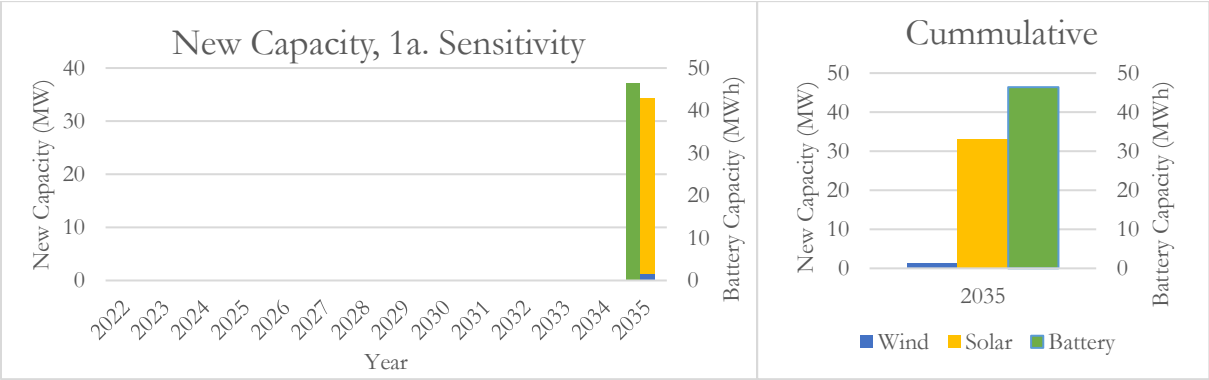

Figure 33 Electricity price sensitivity. (left) New additional capacity, (right) cumulative (MW, MWh).

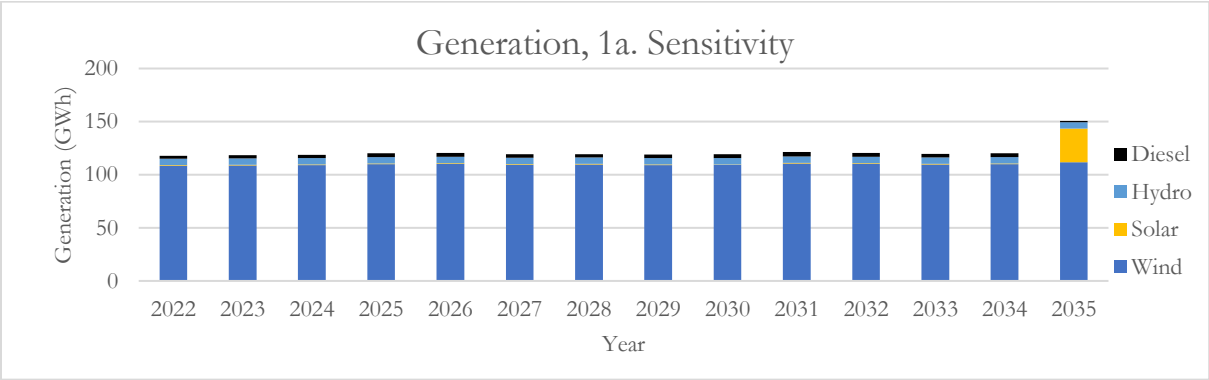

Figure 34 Electricity price sensitivity. Annual local generation (GWh).

The results of this sensitivity analysis have implication at several levels. This implies that if electricity prices are to continue at 2020 levels, then additional wind generation projects on the island would not be economically viable without financial support, even with greater connection to the mainland. With regards to Lewis and Harris specifically this also indicates that the CfD awards, and thus the potential HVDC cable, may be critical to additional local generation with regards to electricity production. Future electricity prices are likely to be driven by commercial-scale renewable projects, with, for example, the UK targeting 40GW of offshore wind by the end of the decade. The CfD scheme represents one of the few remaining support mechanisms available to generators in the UK and the local authority's plan for the area is

contingent on several CfD contracts for future wind parks on the island, with some of the parks' capacities being reserved for the local community. If the HVDC cable connection decision is not overturned then the island may once again find itself continuing to rely on an energy imports, this time in the form of increasing amounts of electricity, itself with an increasing amount of price volatility. In a wider perspective, as support mechanisms are ending for renewable projects this potentially poses a major barrier for other local areas trying to participate on wider electricity markets.

The findings also indicate that in retrospect, the energy modelling work could have alternatively focused on trying to incorporate the other energy sectors, such as heating, at a broader level. The assumption of a high number of heat pumps being included in the future system may not be the best long terms solution for the area and the heat demand on the island could be represented in a broader sense with more options of meeting this demand included, such as using local power directly to produce heat, or hydrogen, which is then stored locally until needed. Adding in this extra flexibility to the system may result in better opportunities for matching local demand and supply and take a further step towards modelling the energy system from a more holistic perspective.

In terms of the thesis work itself, this also highlights the future electricity prices as a major limitation of the study, and a key area for future additional focus. This is discussed further in the following section.

5.5 Limitations

As mentioned above the electricity prices used for the main results were taken from 2019 day-ahead electricity markets. These were used to represent electricity prices with a real-life dataset that included the natural volatility often present in such markets. However, it is likely that representation of the mainland in general was still too oversimplified. In particular, the UK electricity system is due to see a huge increase in wind resources in the coming years, alongside the removal of dispatchable technologies, that will likely have major impacts on the future electricity prices. Better understanding around the coincidence between the future mainland electricity prices, and the local wind production would be beneficial for further understanding. Forecasting future electricity prices represents a research topic unto itself and was not included in the main body of this work, out with the sensitivity results in section 5.4. Additionally, financial agreements such as power purchase agreements (PPA) are also available to generators to offer price security against such volatility. Whilst these can be included in PLEXOS, they were out with the scope of work and were also not included in the thesis.

The study investigated the Western Isles energy system, from a perspective that both domestic heating and transportation loads were electrified in the coming years. It is acknowledged that some industrial loads on the island may also be electrified, adding additional demand to the system. However, data on the industrial sector was extremely difficult to find, despite reaching out to the main producers on the island. Whilst this is a possible limitation, the island does not contain any heavy industry and therefore the near-term impact may be relatively small. Information from different industries on the island would help to complete the overall picture for the coming transition.

It should also be acknowledged that the scenarios investigated in the study do not represent all the possible pathways that the island faces. Given more time, and access to additional datasets, the same process could be used to try and better encapsulate more of the decisions that the local area is faced with.

The model set-up, section 4.1.1, for the LT Plan optimisation was limited by both RAM, as well as the practical impact from the duration of each optimisation run. The timesteps used for the final analysis runs were 56 periods every week. These timesteps are not split into even 3-hour periods, instead there are a higher number of periods during peak times compared to off-peak times. However, in the LT Plan some granularity is still lost compared to the hourly periods that the input data is provided in. This itself may impact the results should be considered.,

Whilst the thesis investigated the impacts of additional HPs and EVs on the energy system, the costs of the technologies themselves were not included in the study. The implementation of these technologies was assumed, due to national goals surrounding both domestic heating and land transport being quite

clear, with an expectation to electrify at a large scale. However, it is acknowledged that if funding for these technologies were to end then the financial burden on individuals on the island will be considerable and may hinder the uptake of both. This becomes even more relevant with regards to the results of the sensitivity analysis and adds further reason to incorporate the island wide heating demand at a broader level than was presented in the study, including alternatives for meeting this demand.

The data collected to form the baseline modelling was collated from numerous different sources. Where possible, these were taken from as up-to-date sources as possible, and then validated with information provided by SSEN. However, the SSEN data was provided relatively late on in the project and thus a more rigorous validation, and possible correction, would have been preferrable.

In the modelling of the electricity system, the distribution network was represented down to the 33/11kV substations. Therefore, no 11kV (LV) cables were modelled. The assumed diffusion of EVs and HPs are likely to occur at the customer end of the LV networks and therefore the modelling did not account for any constraints beyond the 33/11kV transformers. Modelling down to this granularity was out with the scope of the work, however, impacts at this level may occur. Furthermore, the mainland electricity system was not considered. There is currently planned network expansion on the isle of Skye. Considering the findings of this study the planned expansion should take into consideration the benefit of additional capacity from Ardmore to Harris, however incorporating the wider Scottish HV network was not within this scope of work.

From a generation perspective, renewable sources such as solar and wind vary over time. In the modelling carried out for the thesis these generation technologies were represented down to hourly granularity. However, for wind turbines in particular, the island assets often have access to SCADA systems that allow for measurements to be made at 10-minute intervals. Inter-hourly variation was not considered within the model, however it no doubt occurs. Further investigation here would be interesting on several levels. For example, wind speed variation across the island location may mean that the combined capacity factors across the whole region are greater than that assumed in the thesis. Additionally, the variation within the hour would be interesting from a frequency balancing perspective, especially during the time that the island is disconnected from the Scottish mainland.

Discount factors play an important role in energy modelling, as they discount future system costs in comparison to the present value. In a larger model, e.g., a country wide analysis, the discount factors and WACCs have a large impact in terms of differentiating between RES projects, where most of the investment is made up front, and fossil fuel projects, whose capital costs may be lower but require higher fuelling costs throughout their lifetime. (Steffen, 2020) It is therefore important that discount factors are accurate, however there is a lack of financial information for energy projects as capital costs and the financing of projects often remain confidential. If the Western Isles model were expanded to include a larger range of technologies the discount factors would become more important, however for the relatively small scope the assumed discount rates were deemed appropriate assumptions. Furthermore, scenario 1 was tested, during earlier stages of the thesis, at a discount factor of 4% and 8% and the change in results was noted to be quite minor. However, more investigation into their impacts on the results would be beneficial.

The specific impact of EVs on the system was estimated from a demand only perspective. It is likely that as well as smart charging, possible V2G will become more present in future energy systems, and it would be interesting to see the possible impact of leveraging EVs as a demand response technology to allow for the further implementation of local RES. As EVs look to play a major role in our future energy system, this would be a possible future piece of work. Furthermore, with all scenario results including an addition of a major increase in solar generation in the system, greater focus could be given to the possibility of charging during the day. Due to most of the charging occurring at home and during nighttime hours (OFGEM, 2018) the possibility of charging the EVs during the day from solar power will have been extremely limited. This is complicated further by the fact that if EVs are to charge during the day their owner must either have access to a charging station at work, work from home, or not require their car during the day. As general life patterns are changing, with a move towards greater working from home, alongside current studies identifying the benefits of decentralized EV charging from solar this area should be given further consideration in future work. (IRENA, 2019a)

5.6 Future work

As mentioned in 5.4, the modelling could be expanded to include heat from a broader perspective. Heat demand is a major part of the wider energy system in locations such as the Western Isles and representation of heating demand at a broader level would allow for alternative technologies to be included in the model such as heat storages, where the local power generation could be used to produce heat, which is then stored over time, adding greater overall flexibility to the system. In a similar fashion, use cases for hydrogen are increasing and this could be incorporated both to potentially meet local demand, e.g., buses, ferries, or the Stornoway gas grid, as well for potential exports. This itself would pose challenges in terms of data collection, as heating demands in the region are less well quantified than electricity.

With regards to the main results, the benefits of a large-scale BESS could be further investigated. There are possible additional system constraints that have not been included in the model and further insights from the DSO would provide great benefit here. Additionally, the implementation of any BESS could be weighed against alternative technologies that were not included in the study.

The thesis considered the energy system from the perspective of the electricity network running as expected. However, considering the currently failed cable, one further step could be to consider the future systems from a resiliency, or self-sufficiency aspect. For example, whilst maintenance of the subsea cable has been taken into consideration, the possibility of a future connection failure could be explored in terms of the ability of the final system to respond without complete reliance on the diesel power station, as is currently the case. It is likely that an on-island BESS would provide the system with more self-sufficiency in such a future case, however this topic would need to be further explored to allow for more definitive take-aways.

Several topics were identified throughout the process as possible pieces of interesting future studies, for the Western Isles. As well as smart charging for EVs, mentioned above, the concept of demand response could be extended to other controllable assets, such as the electrical heating systems (including heat pumps) and water heat storages that are common in Scotland. The additional technologies discussed in 3.3.1 would all be potential interesting additions, were their technological, economic, or practical hurdles able to be met.

The model focused on the northernmost islands of Lewis and Harris. The local authority includes the southern islands of North and South Uist, Benbecula, as well as Barra and Vatersay. Extending the model to incorporate these sections would allow these areas to be studied in greater detail. Furthermore, as the current cable failure has highlighted the island's dependency on the mainland connection, the possibility of an inter-island connection has been discussed, between North Uist and Harris. Linking up the islands could provide benefits for both areas, in terms of possible sharing of RES resources, as well as providing wider system resiliency in case of a similar cable failure as is currently being experienced.

6 Conclusion

As the energy transition continues, understanding future renewable potential at a local level is important if communities are to benefit in the wider transition to a low carbon economy. The thesis focused on the island of Lewis and Harris, part of the Western Isles in Scotland. With the island containing great RES resources, in particular onshore wind, the local authority has ambitious targets for additional RES production.

A PLEXOS energy model was constructed, with a focus on the island's electricity system. Electrification of heating and transportation was included, via an assumed high uptake of both HPs and EVs. Future potential pathways on the island were explored using scenario analysis. This focused on the replacement of the currently failed subsea cable connection, vital infrastructure for remote locations, as well as the potential removal of the local diesel power station, common legacy infrastructure on islands.

Results for each scenario included a least-cost expansion plan in terms of additional RES and BESS, alongside the future local generation, mainland imports and exports, and electricity system emissions. It was found that the falling cost of solar PV and BESS appeared to make them attractive additions to the system in all scenarios. Furthermore, BESS was found to provide a potential solution to the closure of the diesel power station, whilst also allowing for the earlier addition of a considerable amount of solar PV to complement already installed wind resources on the island.

The importance of the interconnection capacity was highlighted, both in the near-term and future, if the island is to continue to increase local RES production and benefit from increasing electricity exports. Additionally, electrification of heating and transport may present the area with the opportunity for additional local RES. However, it was found through sensitivity analysis that the economic viability of new wind turbines is extremely uncertain due to falling mainland electricity prices. With regards to the Western Isles, this emphasises the importance of the proposed HVDC link and CfD support. Without this support the island may continue to be a net energy importer, exposed to an increasing amount of highly volatile electricity prices. At a wider level, the falling electricity market prices, coupled with higher volatility, appear to prohibit new local RES projects that must be financially viable through electricity sales alone. As commercial-scale generation projects grow in number and size their influence on electricity market prices is likely to increase and further work here would be beneficial. Specifically, better understanding of the temporal correlation between mainland prices and local renewable production.

In retrospect, the modelling could have taken a broader perspective of the heating demands on the island. This would have allowed for alternative technologies to be included, such as thermal energy storages, power-to-heat, and power-to-hydrogen. This would be an interesting area to explore next, potentially with a greater focus on using this additional flexibility to better match local demand and supply. Whilst energy modelling was used to try and explore between different pathways on the Western Isles it is acknowledged that not all the aspects of the energy system were included, mainly due to time constraints and data availability. As well as a broader representation of heating demands, incorporating sectors such as agriculture, marine transport, and further details on the industrial demand would allow for a more holistic picture of the energy transition on the island.

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Annex

8 Annex A: Additional background information

8.1 Scottish Islands

Scotland has over 900 islands, the majority of which can be grouped into four main areas: Inner Hebrides, Outer Hebrides (Western Isles), Orkney, and Shetland. Initial background research was conducted on the latter three groups, with the highlights in the Table 15 and Table 16.

Table 15 Background information for Western Isles, Orkney, and Shetland

	Outer Hebrides	Orkney	Shetland
Population (no.)	27,000	22,000	23,000
Co-ordinates (LAT, LONG)	57.76°N, 7.02°W	58.98°N, 2.96°W	60.53°N, 1.27°W
Islands (no., no. inhabited)	70, 15	70, 20	100, 20
Area (km^2)	3,000	1,000	1,500
Tourist visits (2017)	219,000		

Table 16 Elec. Sector info, Western Isles, Orkney, Shetland (UK Renewables, 2021) (SSEN, 2020a)

	Outer Hebrides	Orkney	Shetland
Electricity demand, min-max (MW)	6-29	7-46	11-48
Fossil fuel capacity (MW)	49.7	16	66
Onshore wind installed (MW)	44.96	45.7	12.14
Consented onshore wind (MW)	423.3	43.5	556.1
Connection to mainland (MW)	23[8] + 14	40	0[9]

[8] Currently failed.
[9] Project to increase this to 600MW via SSEN subsea cable is in construction phase (SSEN, 2020).

9 Annex B: Energy System, additional information

9.1 Model

The electricity grid on Lewis and Harris was built based on the following schematic, taken from the Scottish Hydro Electric Power Distribution Long Term Development Statement

9.1.1 33kV grid schematic

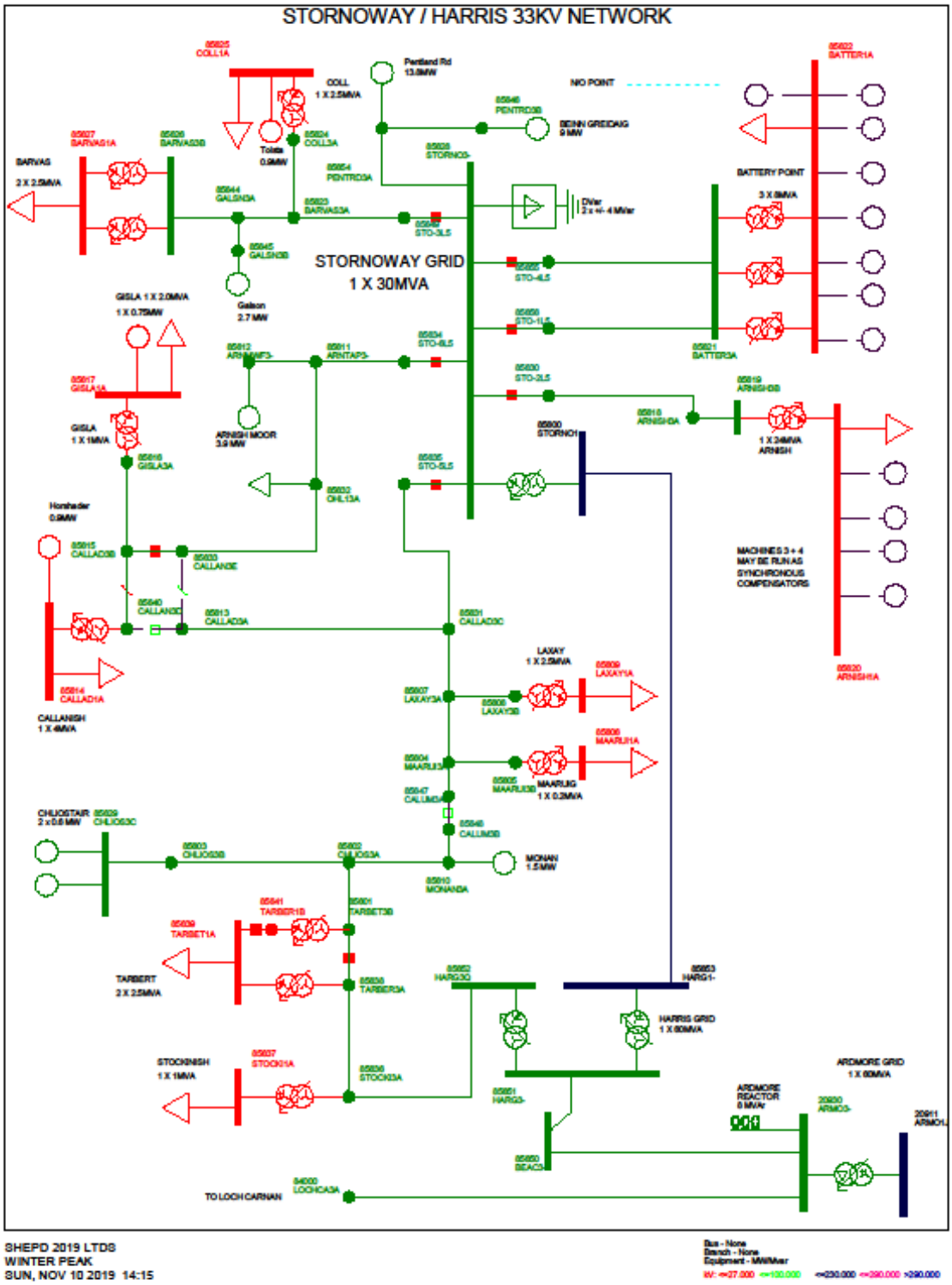

Figure 35 SHEPD Long Term Development Statement

9.1.2 PLEXOS visualisation

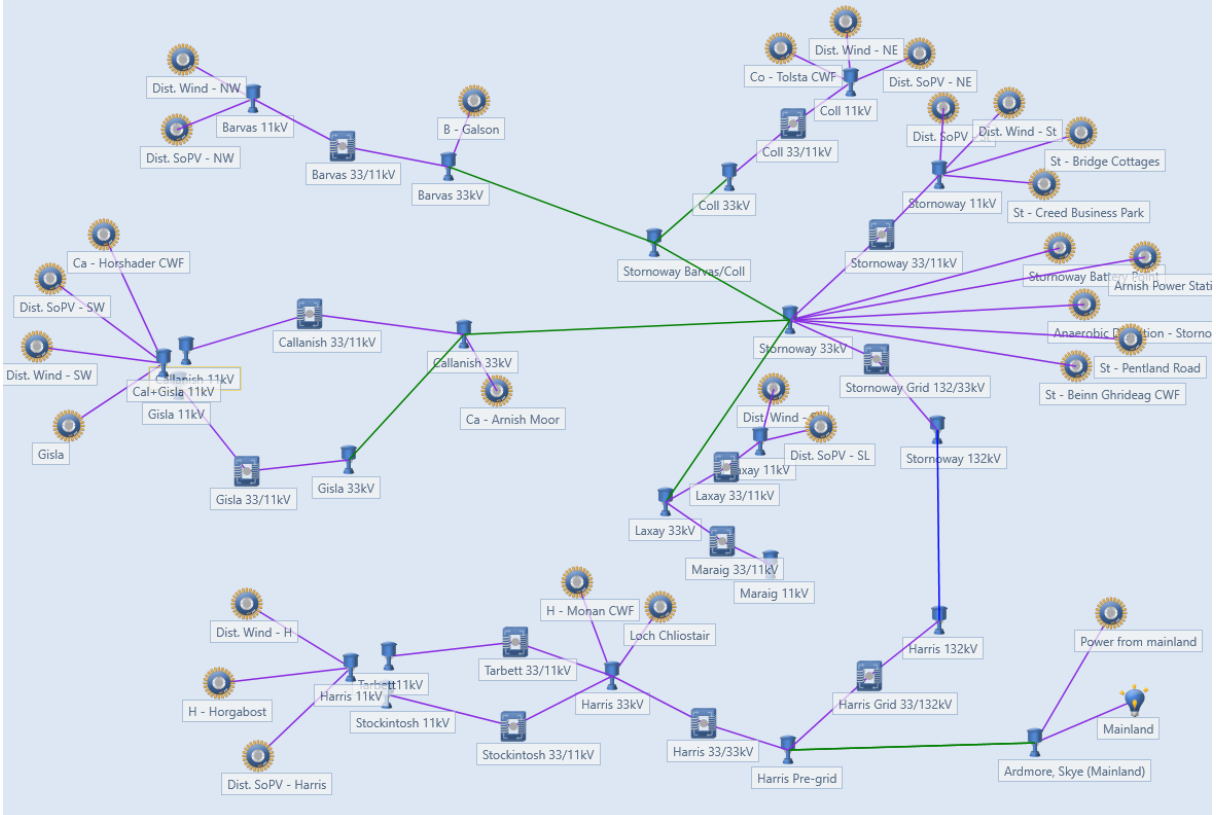

Figure 36 Schematic from PLEXOS of representation of transmission grid, including generators.

9.2 Data collection – classification of aggregated areas

9.2.1 Data collection and classification of area sets

Data collected for the model was often supplied in different aggregated area levels. The definition of these area is given below, listed in increasing resolution:

- **Local Authority.** The Western Isles is a single local authority (S12000013), one of 32 across the whole of Scotland. This area encompasses a larger area than the model represents. Numerous datasets at this level are available, however for the modelling work carried out it was deemed too high level to be relevant. Data presented in the introductory sections included local authority information, to create a picture of the wider energy system.
    - Regional Renewable Statistics (Department for BEIS, 2020a)
    - Total final energy consumption 2005-2018 (Department for BEIS, 2020b)
    - Regional and local authority electricity consumption (Department for BEIS, 2020c)
- **Middle Supper Output Area (MSOA).** There are 9 MSOAs across the whole of the local authority.
- **Lower Super Output Area (LSOA).** The 9 MSOAs are broken down further into 36 LSOAs. The most detailed annual electricity data from BEIS is provided at this level**.**
- **Output Area.** There are 253 different output areas. Data was collected at this level for the following:
    - Census Data. Including population data, number of dwellings, dwelling type, central heating source, vehicle count. (National Records of Scotland, 2017)
- **Postcode Area.** At the time of the data collection there are 1093 different postcodes across the whole local authority. These can be matched to best-fitting Output Areas, or alternatively grouped into 9 different postcode groups: HS1 – HS9. Data collected at this level included:
    - Energy Performance Certificates (EPC). Certificates for properties on the island were available, dating back to 2013. The dataset included over 6000 certificates. (Statistics.gov.uk)
    - Ofgem distributed generation information. (OFGEM, 2021a)

The best-fit matching between the above area levels can be conducted relatively quickly via the Office for National Statistics portal. (Office for National Statistics,, 2020)

Further datasets that were collected during the research, but did not fall into the hierarchy above, included:

- **Nongasmap**. Heating fuel type by property, broken down into 'data zones', however matching these with the electricity network and other datasets proved unsuccessful. (Nongasmap, 2021)

9.2.2 Classification of demand regions

The following table details the output areas that were grouped together to make the six demand regions, using SSEN 11kV schematics and Scotland's Census Area Profiles. (National Records of Scotland, 2017) .

Table 17 List of 'output areas', grouped by the PLEXOS demand region.

Demand Region	Output Area
Stornoway	S00135149, S00135172, S00135173, S00135250, S00135251, S00135289, S00135290, S00135174, S00135175, S00135194, S00135220, S00135252, S00135253, S00135254, S00135291, S00135292, S00135293, S00135193, S00135196, S00135197, S00135198, S00135219, S00135294, S00135295, S00135188, S00135190, S00135203, S00135204, S00135208, S00135256, S00135177, S00135181, S00135182, S00135183, S00135184, S00135185, S00135186, S00135187, S00135189, S00135192, S00135176, S00135178, S00135179, S00135180, S00135216, S00135217, S00135218, S00135211, S00135212, S00135213, S00135214, S00135296, S00135297, S00135191, S00135200, S00135205, S00135206, S00135207, S00135209, S00135210, S00135298, S00135299, S00135170, S00135195, S00135199, S00135201, S00135202, S00135215, S00135165, S00135166, S00135167, S00135168, S00135169, S00135171, S00135249, S00135146, S00135147, S00135148, S00135151, S00135163, S00135164, S00135143, S00135144, S00135145, S00135162, S00135283, S00135284, S00135152, S00135234, S00135235, S00135236, S00135237, S00135115
Northeast Lewis	S00135150, S00135246, S00135247, S00135285, S00135286, S00135221, S00135222, S00135223, S00135224, S00135225, S00135226, S00135258, S00135227, S00135228, S00135229, S00135230, S00135231, S00135232, S00135233
Northwest Lewis	S00135245, S00135130, S00135131, S00135137, S00135138, S00135139, S00135140, S00135279, S00135280, S00135281, S00135282, S00135141, S00135142, S00135238, S00135259, S00135277, S00135278, S00135239, S00135240, S00135241, S00135242, S00135243, S00135244, S00135300, S00135301
Southwest Lewis	S00135117, S00135125, S00135126, S00135133, S00135134, S00135127, S00135132, S00135135, S00135136, S00135275, S00135128, S00135129, S00135276, S00135118, S00135119, S00135120, S00135121, S00135122, S00135123, S00135124
South Lewis	S00135105, S00135106, S00135107, S00135108, S00135109, S00135110, S00135111, S00135112, S00135113, S00135103, S00135104, S00135114, S00135116, S00135265, S00135273, S00135274
Harris	S00135094, S00135095, S00135096, S00135097, S00135098, S00135099, S00135100, S00135262, S00135305, S00135306, S00135091, S00135092, S00135093, S00135101, S00135102, S00135264, S00135269, S00135270, S00135271, S00135272

9.3 Electricity prices

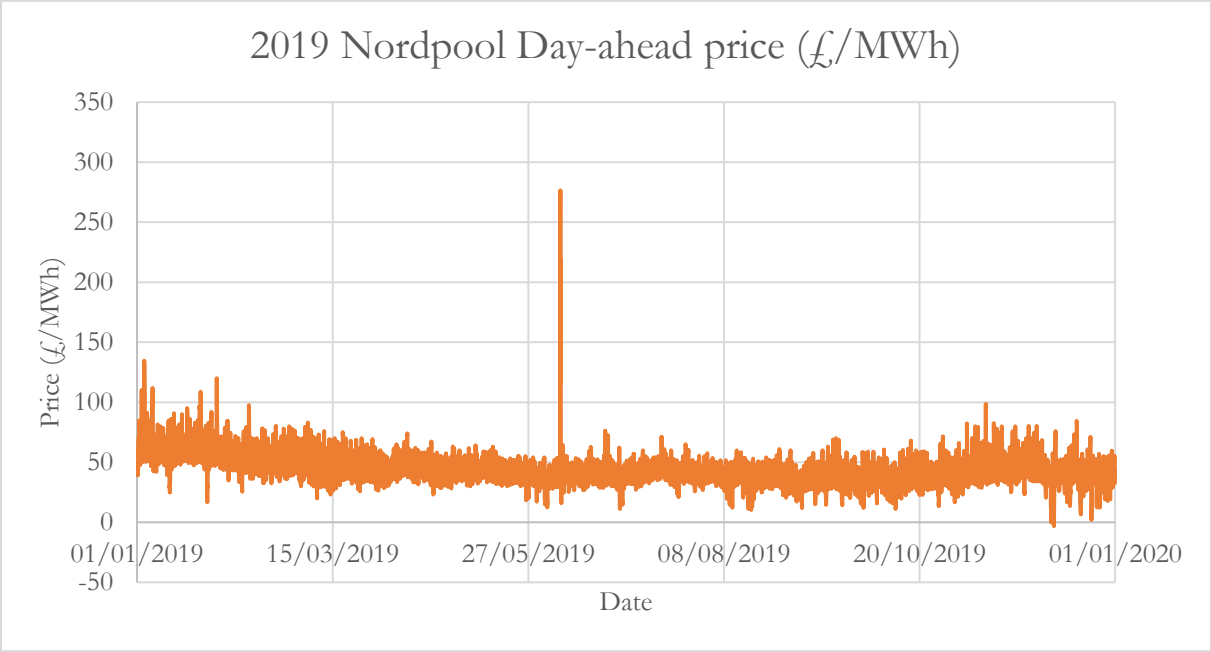

Figure 37 Graph of Nordpool 2019 day-ahead prices

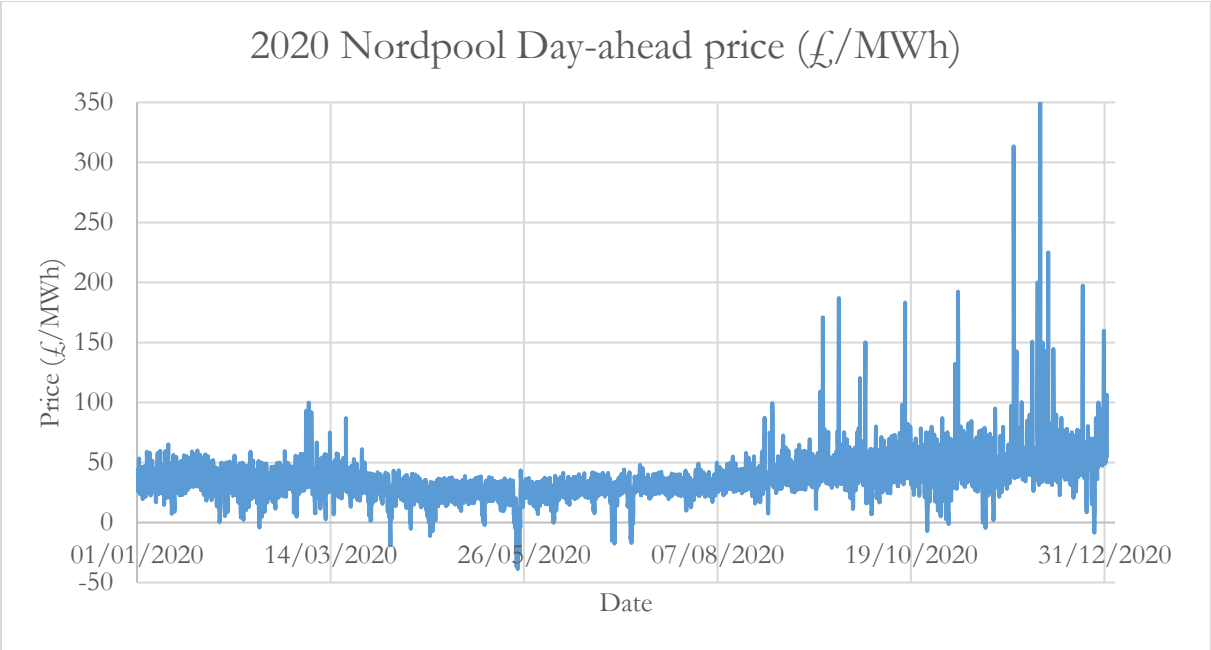

Figure 38 Graph of Nordpool 2020 day-ahead prices

9.4 Western Isles wide wind power generation

9.4.1 Installed wind turbines.

All wind turbines installations of 100kW or more are displayed in Table 18. The table includes the total installed capacity of the project, turbine size, number of turbines installed, estimated hub height, turbine type, location and year built. (Department for BEIS, 2021) (UK Renewables, 2021) (The Wind Power)

Table 18 Operational wind turbine projects on the Western Hebrides

Name	Total (MW)	Turbine Size (MW)	Num. (#)	Hub height (m)	Turbine type	Location	Year built
Lewis							
Arnish Moor	3.9	1.3	3	60	N60/1300	Lewis	2007
Beinn Ghrideag CWF	9	3	3	72	E82/3000	Lewis	2015
Bridge Cottages	0.1	0.1	1	25		Lewis	2014
Creed Business Park	0.33	0.33	1	44	E33/330	Lewis	2014
Horshader CWF	0.9	0.9	1	50	E44/900	Lewis	2012
Galson	2.7	0.9	3	50	E44/900	Lewis	2015
Pentland Road	13.8	2.3	6	108	E82/3000	Lewis	2013
Tolsta CWF	0.9	0.9	1	50	E44/900	Lewis	2013
Harris							
Horgabost	0.1	0.1	1	25		Harris	2016
Monan CWF	1.5	0.5	3	55	E40/500	Harris	2015
Uists & Benbecula							
Locheport CWF	1.8	0.9	2	50	E44/900	North Uist	2019
Liniclate Wind Farm	0.9	0.9	1	50	E44/900	Benbecula	2008
Bornish	0.33	0.33	1	44	E33/330	South Uist	2016
Lochcarnan CWF	6.9	2.3	3	85	E70/2300	South Uist	2013
Barra							
Barra CWF	0.9	0.9	1	50	E44/900	Barra	2014

9.4.2 Consented projects

There are also several consented projects that are yet to be operational. These are displayed in Table 19.

Table 19 Consented wind turbine projects on Western Hebrides.

Name	Total (MW)	Turbine Size (MW)	Turbines (no.)	Lat.	Long.	Location
Arnol	1	0.1	1	58.34	-6.58	Lewis
Bheinn Thulabaigh	6	6	1	58.23	-6.49	Lewis
Druim Leathann	46.2	3.3	14	58.35	-6.25	Lewis
Muaitheabhal (Uisenis)	138.6	4.2	33	58.02	-6.54	Lewis
Muaitheabhal East Ext.	25.2	4.2	6	58.02	-6.51	Lewis
Muaitheabhal South Ext.	25.2	4.2	6	58.00	-6.59	Lewis
Stornoway Wind Farm	180	5	36	58.21	-6.48	Lewis
Total	**422.3**	**-**	**-**	**-**	**-**	**-**

Druim Leathann and Muaitheabhal were both successful applicants of the UK Governments 3rd round of Contracts for Difference (CfD), one of the main incentive mechanisms for supporting low carbon electricity generation in the UK. Successful applicants in each round of the CfD scheme are guaranteed the strike price for energy delivered by the project for 15 years via subsidy payments when the market price is below the strike price, and paybacks from the generator when the market price rises above. For both the CfD projects the strike price and expected year of delivery is displayed in Table 20.

Table 20 CfD information for Druim Leathann and Muaitheabhal

Name	Capacity (MW)	Turbine Size (£/MWh)	Year of Delivery
Druim Leathann	49.5	41.61	2024/2025
Muaitheabhal	189	39.65	2023/2024

10 Full Scenario Results

Scenario 1a – Baseline – New Cable

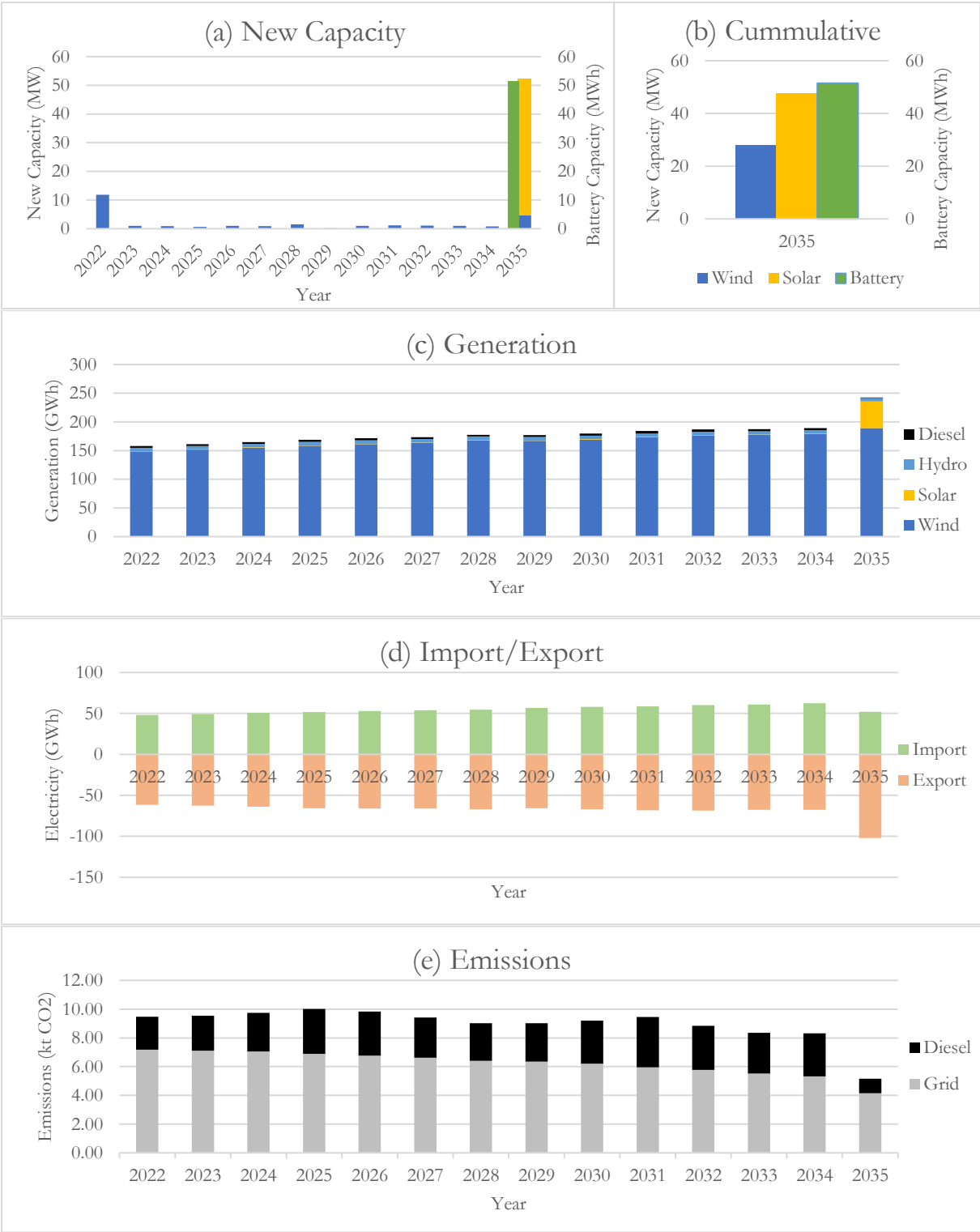

Figure 39 Scenario 1a results.

From top to bottom, (a) New capacity (MW, MWh), (b) Final cummulative additional capacity, 2035 (MW, MWh), (c) On island generation per annum (GWh), (d) Imports/Exports (GWh), (e) Electricity system emissions (kt CO2).

Scenario 1b – New Cable + No Diesel 2030

Figure 40 Scenario 1b results

From top to bottom, (a) New capacity (MW, MWh), (b) Final cummulative additional capacity, 2035 (MW, MWh), (c) On island generation per annum (GWh), (d) Imports/Exports (GWh), (e) Electricity system emissions (kt CO2).

Scenario 2a – Additional Connection

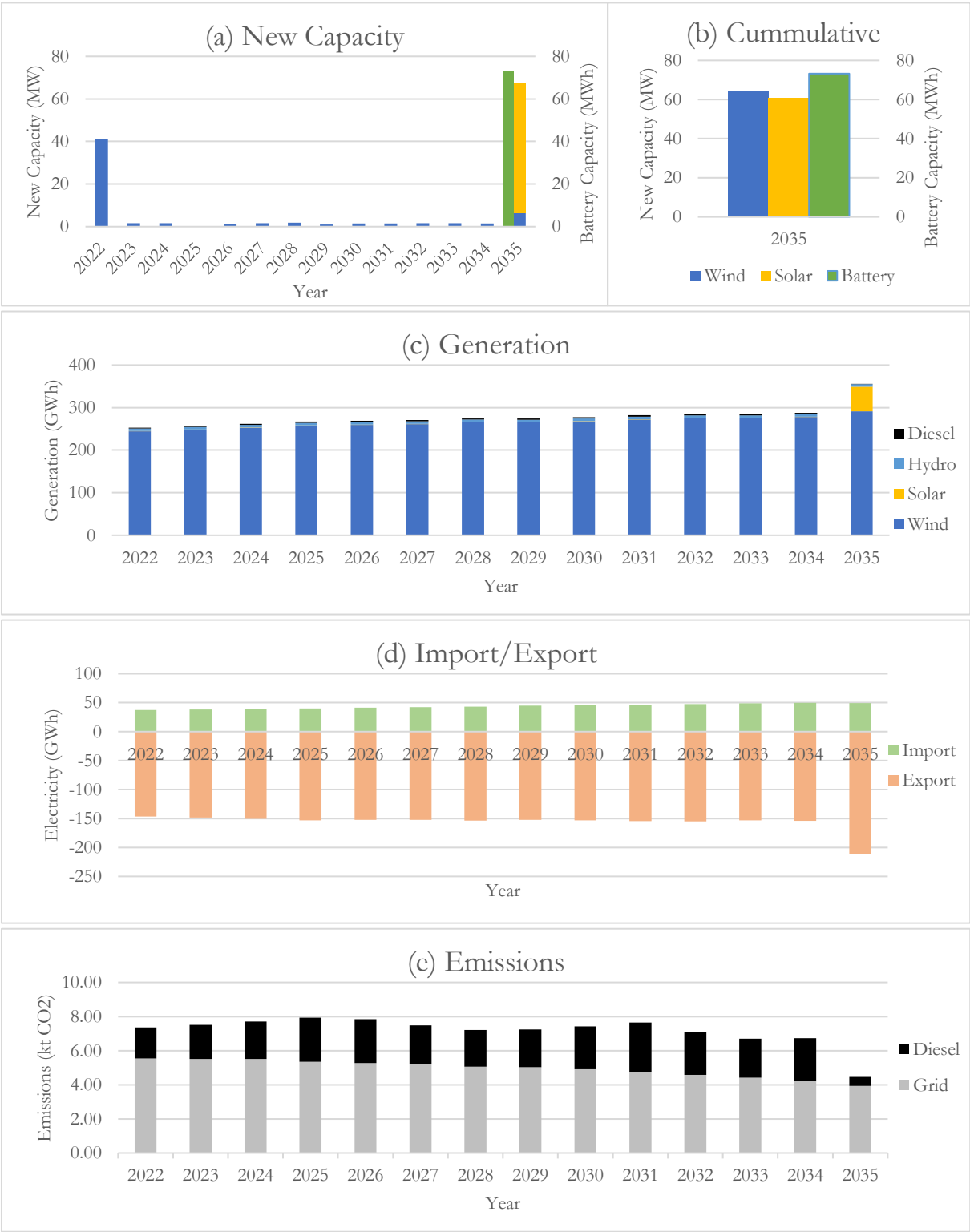

Figure 41 Scenario 2a results

From top to bottom, (a) New capacity (MW, MWh), (b) Final cummulative additional capacity, 2035 (MW, MWh), (c) On island generation per annum (GWh), (d) Imports/Exports (GWh), (e) Electricity system emissions (kt CO2).

Scenario 2b – Additional Connection + No Diesel 2030

Figure 42 Scenario 2b results

From top to bottom, (a) New capacity (MW, MWh), (b) Final cummulative additional capacity, 2035 (MW, MWh), (c) On island generation per annum (GWh), (d) Imports/Exports (GWh), (e) Electricity system emissions (kt CO2).

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