Alderney future power supply scenarios – Scoping study

ORE Catapult Development Services Ltd (ODSL), commissioned by the States of Alderney Energy Team

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SCOPING STUDY REPORT

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NOMENCLATURE

AUV	Autonomous Underwater Vehicle
AEL	Alderney Electricity Ltd
AET	Alderney Energy Team
ATR	Autothermal Reformer
ASHP	Air Source Heat Pump
BEIS	Business, Energy and Industrial Strategy
CAPEX	Capital Expenditure
CCUS	Carbon Capture, Utilisation and Storage
CoE	Centre of Excellence
CoP	Coefficient of Performance
FOSS	Floating Offshore Substation
FOW	Floating Offshore Wind
FOWT	Floating Offshore Wind Turbine
HHV	Higher Heating Value
HV	High Voltage
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
IRENA	International Energy Agency
IRR	Internal Rate of Return
kV	kilo Volt
kW	kilowatt

LCOE	Levelised Cost of Energy
LCOH	Levelised Cost of Hydrogen
MW	Megawatt
MWh	Megawatt hour
NM	Nautical Mile
OPEX	Operational Expenditure
ORE	Offshore Renewable Energy
OSS	Offshore Substation
O&G	Oil and Gas
O&M	Operations and Maintenance
PEM	Proton Exchange Membrane
PPA	Power Purchase Agreement
ROV	Remotely Operated Vehicle
SMR	Steam Methane Reformer
SoA	States of Alderney
SOE	Solid Oxide Electrolysis
SPF	Seasonal Performance Factor
ST	Solar Thermal
TLP	Tension Leg Platform
TWh	Terawatt hour
ULS	Ultimate Limit State
WACC	Weighted Average Cost of Capital

EXECUTIVE SUMMARY

The self-governing Channel Island of Alderney is a UK crown dependency. It is part of a group of Islands known as the Bailiwick of Guernsey and is the northern most inhabited of the Channel Islands. The States of Alderney (SoA) Policy and Finance Committee's Energy Team have commissioned Offshore Renewable Energy Catapult Development Services Limited to complete an island energy systems scoping study establishing the potential hybrid 'mix' of power supply and storage technologies which, exist or are being developed, and that could meet the island's strategic energy system objectives in short (0-10 years), medium (10-20 years) and long term (20+ years) scenarios.

The strategic energy system objectives were identified as:

1. Minimising cost of energy,
2. Reducing or mitigating energy supply risks, and
3. Minimising or eliminating the use of carbon emitting energy sources.

The island's current energy system is wholly dependent on fossil fuels and is subject to global market price fluctuations. To compound this, it is reliant on an ageing shipping fleet, responsible for transporting and importing the required fuels and which will need replacement within the coming decade and likely leading to further increased energy costs in future. Alderney's grid is owned and operated by Alderney Electricity Ltd (AEL) who are mid-way through an upgrade programme to bring the grid up to current safety and switching standards. As such, the grid is not able to receive domestic renewable energy feeds and is unlikely to be able to do so for some time until further upgrades are completed. It is, however, capable of distributing up to 5 MW. Electricity generation on the island is produced via 1-4 500 kW diesel generators with consumers paying approximately 44 pence per unit (more than double UK average). Households on the island predominantly use Kerosene oil for heating and pay 78.73 pence per litre (approximately 30 pence per litre more than UK average).

To establish what mix of renewable energy technologies might help Alderney in the short and medium terms, we used HOMER Pro software to simulate the Alderney electricity network. HOMER (Hybrid Optimization of Multiple Energy Resources) is analytical software which allows microgrids to be simulated by balancing a required load with the energy generation available on the grid.

The island electricity demand was provided by AEL. Within the model we investigated combinations of several generating technologies as well as battery storage options.

Short-term scenario

In the short-term scenario for electricity generation, the preferred option was determined to be installation of a single refurbished onshore wind turbine. Modelling indicated that it could displace approximately 700,000 litres of diesel per year saving almost £400,000 in diesel fuel costs. This could be funded through a competitive tender whereby Alderney offers to fund the project via an agreed power purchase agreement (enabled due to the fuel cost saving expected by the installation). The turbine would be owned and operated by a private developer, who would also fund the initial capital cost and ongoing maintenance. With this scenario we estimate that approximately £200,000 of the fuel cost savings could be retained to use for other initiatives or to offset consumer bills.

Grid constraints and high electricity costs pose a significant challenge for the introduction of domestic renewable heat production. Using typical household types found on the island, as proposed by a previous Energy Saving Trust report, was found to significantly underestimate the levels of insulation and as a result overestimate likely heat demand. The conclusion for the short-term scenario however remains consistent with the Energy Saving Trust report in that Alderney's housing stock should be surveyed and supported to improve insulation properties, reducing oil demand on the Island. To do this cost effectively for all households the creation of a community energy group could be established by the SoA. This would support local residents in identifying potential home energy savings and perhaps even co-ordinate bulk procurement of products and installers to maximise cost efficiencies.

Medium-term scenario

The medium-term scenario for electricity generation builds upon the preferred short-term scenario and increases the volume and mix of renewable energy production. We also recommend battery storage for grid stability purposes. A mix of onshore wind and solar PV combined with battery storage could reduce diesel fuel consumption by as much as 82%, enable the grid to be operated with only a single 500 kW diesel generator and enable the current AEL generator engine fleet to be halved. The optimal mix of solar and onshore wind appears to be approximately 50:50 with a suggested renewable capacity of 3-4 MW. It's likely this scenario could be managed similarly to the early-stage scenario with project developers upfronting CAPEX and OPEX costs in return for an agreed PPA.

The barriers to the introduction of renewable heating solutions remain in the medium term. As such, focus shifted to modelling of the impact of varying levels of air source heat pump uptake on the island's electricity demand. It was found that up to 5% household uptake could be handled by the grid, but that AEL should monitor this closely for grid stability purposes. Uptake of 15% could double current electricity demand. When considering medium term electricity generation scenarios, the island's strategy for de-carbonising the heating system must be carefully considered if electrification is involved to future proof the grid system.

Another priority that SoA identified for Alderney is to develop its territorial waters, for which the seabed rights are owned by the island. Up to 3 GW of tidal stream resource has been identified in these waters, however without a route to market (e.g., an interconnector) and the ability to pay a higher than market price feed in tariff for still developing technologies it is deemed unlikely this location will be attractive to developers in the short and medium term. Interconnector CAPEX estimates were established, indicating that a bi-polar HVDC connection capable of 800 MW import and export with France would cost approximately £352m. An alternative could be to connect to Guernsey which we estimated at £384m. An alternative may be to install a transmission cable (much like that installed between France and Jersey) but which only allows for import, or export of electricity. Capex estimates for a 220 MW cable link to France and Guernsey were £25m and £51m respectively. For either of these options detailed feasibility studies would be required along with the identification of a suitable business case to fund them with the aim of unlocking revenue potential of Alderney's territorial waters.

Long-term scenario

For the long-term scenario focus shifts to the potential of the hydrogen production industry. The production of green hydrogen (produced using only renewable energy) is expected to increase dramatically and dominate the market by 2050. Hydrogen production may provide the key for Alderney to unlock the significant tidal stream resources within its territorial waters and perhaps remove heating system reliance on fossil fuels.

1 INTRODUCTION

The Channel Island of Alderney, a UK crown dependency and part of a group of Islands known as the Bailiwick of Guernsey is the northern most inhabited of the Channel Islands. Alderney is self-governed by the States of Alderney (SoA) which consists of an elected President and 10 States Members. Routine government is performed by three principal committees Policy and Finance, General Services, and Building and Development Control. These three committees are run by States Members and each work under a different mandate and have a separate budget. Certain 'transferred services' namely policing, customs and excise, airport operations, health, education, social services, childcare and adoption are the delegated responsibility of the States of Guernsey.

The island's current energy system, which remains the responsibility of the SoA, is wholly dependent on fossil fuels and is subject to global market price fluctuations. It uses an ageing shipping fleet, responsible for transporting and importing the required fuels, likely leading to further increased energy costs in future when replacement vessels or an alternative method of import is required.

The States of Alderney Policy and Finance committee's Energy Team have commissioned Offshore Renewable Energy Catapult Development Services Limited to complete an island energy systems literature review and scoping study report establishing the potential hybrid 'mix' of power supply and storage technologies which, exist or are being developed, and that would meet the island's strategic energy system objectives.

Renewable energy generation technologies to be considered include solar photovoltaic (Solar PV) and solar thermal, onshore, and offshore wind, tidal stream, air source and ground source heat pumps, biomass and energy storage technologies including pumped, batteries and hydrogen. Interconnector options will also be considered as part of this study.

As a precursory activity to this scoping study a literature review was completed which assessed relevant available information on Alderney's energy system, available renewable resources on the island and overview of available renewable generation and storage technologies. The literature review also summarised relevant islands energy system case studies where once fossil fuel reliant islands have, or are in the process of, shifting their energy system to more sustainable, renewable sources of energy production.

1.1 Strategic objectives

The following are the prioritised strategic objectives for Alderney's future energy system as set out by the States of Alderney Energy Team:

1. Minimising cost of energy
2. Reducing or mitigating energy supply risks, and
3. Minimising or eliminating the use of carbon emitting energy sources

The scoping study will assess various energy system arrangements and identify priority future power supply mix scenarios for the short-term (0-10 years), medium-term (10-20 years) and long-term (20+ years) and consider both renewable energy generation technologies as well as energy storage options for the island. Guided by the strategic energy system objectives outlined above and considering constraints including cost and impacts on the character of Alderney, high level energy system scenarios will be identified. It is assumed that the States of Alderney Energy Team will carry out further detailed studies in relation to the scenarios identified by this study to fully understand their impacts both on the energy system and its economics prior to possible implementation.

1.2 Alderney energy system challenges

There are several strategic challenges specific to Alderney's energy system which this scoping study has considered when developing the various scenarios:

- Because of Alderney's reliance on fossil fuel for electricity production, careful consideration is required when introducing renewable energy onto the grid. Displacing fossil fuel requirement could impact importing costs due to changes in economies of volume. Grid stabilisation will also quickly become challenging with the introduction of intermittent renewable energy.
- Due to the age of the vessels used for importing fuels to Alderney (and other Channel Islands) it is anticipated that either new vessels will need to be acquired or an alternative method for the importation of fuels will need to be implemented within the decade. This is expected to increase the 'landed uplift' cost of fuel which is currently 10 pence per litre and is passed directly on to consumers.
- AEL are currently halfway through a safety and switching upgrade programme with completion expected within the next decade. As such any AEL reserves are currently prioritised for these works.
- Feeding of domestic electricity production onto the grid is not possible. Significant grid upgrade works would be required to enable this.
- There is no interconnector connecting Alderney's electrical grid to another, this limits the potential for renewable energy generation and export to a level below on island consumption levels.
- The SoA hold seabed rights out to the 3 NM territorial limit. This places the island in a unique position, with the potential to reap economic benefits through the extraction and exporting of offshore renewable energy in addition to revenue generation from leasing areas of seabed within the 3nm limit to project developers. As a result, the Alderney Energy team have indicated that tidal stream energy development should be considered a priority given the revenue generation potential for the island.

1.3 Alderney's current energy system

1.3.1 Fuel and electricity supply

Alderney Electricity Ltd (AEL) is the monopoly supplier and distributor of electricity on the island. The company is a wholly vertically integrated utility, responsible for everything from the import of fuel oil for generation to the billing of units consumed. The company owns and operates the island power station and the distribution grid and is majority owned by the States of Alderney. AEL bulk imports Diesel and Kerosene fuels via vessel tankers with 4 shipments per year. Isotanks (23,000L capacity) are used for importing unleaded fuel to the island. See Table 1 below for an overview of annual fuel imports as provided by AEL.

Table 1 – Breakdown of the types and annual quantities of fuels imported by AEL in 2021.

Imported fuel	Usage	Annual import quantity (litres)
Diesel	Electricity production	1,600,000
Kerosene Oil	Heating fuel	2,000,000
Diesel	Transport	400,000
Unleaded Petrol	Transport	350,000

Fuels are priced according to Platt's spot price on the day of loading to the import tanker. A Platt's spot price plus supplement provides an indicative 'landed cost' per litre of fuel which covers all costs associated with shipping, harbour dues, handling etc. For the most recent shipment to Alderney at the end of 2021 the premium paid was approximately 10p on a Platts price of 46p per litre giving a landed cost of approximately 56p per litre for both kerosene and diesel. AEL manages a fuel storage facility capable of holding 1,600,000 litres of diesel.

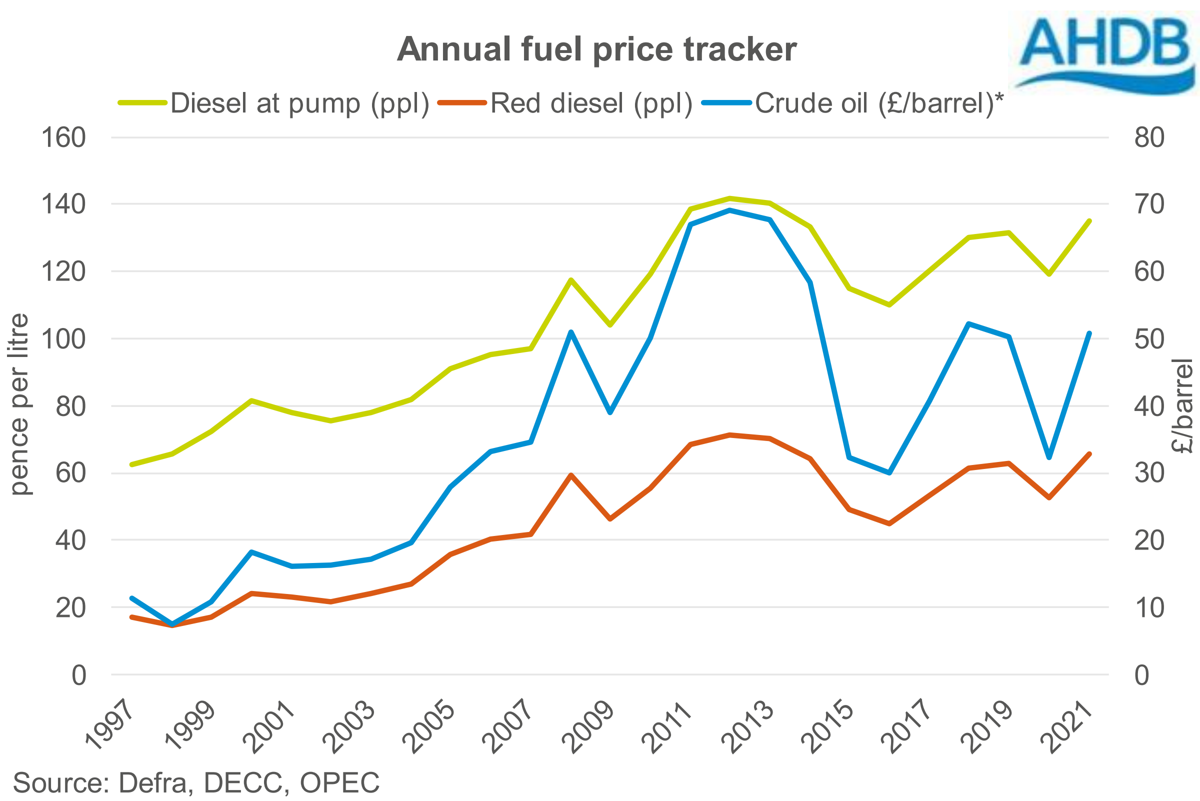

Figure 1 – Annual UK diesel (pence per litre) and crude prices (£/barrel) between 1997-2021 [37]

Figure 1 shows the upward trend of diesel and crude oil prices in the UK, a trend to which Alderney's energy system is currently vulnerable to. In February 2022, crude oil hit its highest price since 2014 reaching $95.56 a barrel [1]. AEL currently sell diesel to consumers at 78.76 pence per litre and Kerosene heating oil at 78.73 pence per litre (minimum 1,000 L quantity) [2].

A significant challenge to be faced within the decade for the Channel Islands (Alderney, Guernsey & Jersey) is that the vessels used for importing fuels (owned by the States of Guernsey) will reach a 20-

year age cap set by serving port fuel refineries. At this point the vessels will unlikely be accepted into the refineries for transporting fuels. Whilst the Channel Islands consider their options, it is likely at this point the 10 pence per litre supplement for establishing the landed cost of fuel mentioned above will increase for Alderney. AEL will have little choice but to pass this cost increase on to consumers.

Liquid petroleum gas (LPG) supplies are also available on the island via separate supplier Blanchard [3] who sold approximately 91,000kg (178,000 litres) in 2020 [4]. The split of LPG consumption is estimated 50% commercial and 50% domestic. LPG is predominantly used for gas cookers and not space heating.

1.3.2 Electrical system

Total current electricity demand on Alderney typically varies between 300 kW and 700 kW with peak demand reaching 1.3 MW during the summer tourism period. Total billed electricity consumption during 2021 was 5.98 GWh [5]. Total outputs to the grid were 6.43 GWh giving network losses of 7.5%. Including station consumption of 74 MWh, total island generation was 6.51 GWh.

In 2021 AEL procured 8x 500 kW Perkins diesel engine power generators, including 2 Perkins 650 kVA standby generators. AEL run varying numbers of generators (1-3) depending on anticipated demand with 2 engines capable of producing enough power for 700 kW peak and 3 engines meeting annual peak demand of 1.3 MW. The system is designed with a redundancy of 100% and each side has 30% excess output capacity to facilitate warranty and preventative maintenance schedules and adequate capacity under fault condition scenarios. The system currently delivers an operational efficiency of 40%. This is expected to rise further when fully automated.

Both high (HV) and low voltage (LV) cabling is predominantly buried underground, the exception being a single HV overhead transmission line running from Sharpe's Farm near Longis Common out to the east end of the island and a mixture of low voltage overheads and facia mounted LV supplies in the town area. There is adequate capacity on the primary HV grid across the whole island. It is estimated that the current grid capacity for small scale renewable energy is approximately 300 kW.

In the last 7 years AEL have invested over £2.5 million in improvements to grid, generation, and system management infrastructure. Creating a smart platform as a foundation to introduce technology to reduce carbon footprint and meet future energy challenges is already underway. The most recent grid upgrades completed in 2020/2021 were to those sub-stations key to network switching protocols and focussing on delivering safe and compliant switching capability. According to AEL, the primary HV network should be considered adequate for the distribution of up to 5 MW. An area that will require focus from domestic scale energy generation is the grids capability to receive the energy, as AEL have mentioned, it depends on location, i.e., the side of the grid access is required geographically. The assumption by AEL is to move 5 MW around the island on the HV grid equivalent to the capacity required to meet the island's total requirement. It is currently accepted that it is not possible to feed domestic generated electricity back on to the grid.

1.3.3 Heating system

Kerosene oil is the most common heating fuel on Alderney with AEL estimating that 2 million litres of kerosene is used annually. It is estimated that this is split 50% for commercial use and 50 % domestic use. The current price of kerosene sold by AEL is 78.73p per litre [2]. Bottled LPG gas is also used on island predominantly for gas cookers and heaters with approximately 91,000 kg (178,000 litres) sold in 2020. A small amount of electric heating is also used on the island although this is typically only for newbuild properties with excellent energy efficiency ratings due to the high cost of electricity on the Island. There are also small number of domestic solar hot water systems installed on households.

2 METHODOLOGY

2.1 Technology appropriateness and constraints review

We considered the following three timescales for Alderney energy policy:

1. Short term (0-10 years)
2. Medium term (10-20 years)
3. Long term (20+ years)

The first task was to determine the most appropriate electricity and heating technologies for the island within each timeframe. To do this, we conducted an in-depth literature review. We reviewed reports provided by Alderney Energy Team (AET) and publicly available literature. This covered the following areas:

- The current status of the Alderney electricity system (including grid coverage, fuel consumed and island electricity load)
- Operating principle, market trends and approximate costs of renewable energy technologies (wind, solar, tidal stream, wave) and storage (hydrogen, battery, pumped hydro).
- The renewable energy resources available to Alderney (wind speed profiles, solar irradiation, tidal stream resource)
- Case studies of other islands, to identify lessons that Alderney could learn from (Eigg, Faroe Islands, Shetland, Isle of Scilly and Ushant)

This was finalised and submitted to AET in January 2022. We combined this knowledge with insight gained from meetings with representatives from AET and Alderney Energy Ltd (AEL). We held several internal workshops, iterating on the potential technology options, which allowed us to formulate appropriate technologies for each scenario. These were decided by considering the following:

- Market readiness and technology maturity
- CAPEX intensity
- Preferences of AET and AEL
- Strength of Alderney electricity grid and estimated timescale of interconnector

2.2 Market research

The aim of this section was to get further insight into the various technologies proposed for the energy scenarios. The main emphasis was on the short-term scenario, as the costs and performances of these technologies are better understood, and they present almost immediate benefits in terms of decarbonisation and energy security. We approached suppliers to better understand the costs of the technologies, as well as how effectively they could be incorporated into the existing Alderney electricity grid.

For the energy technologies, we identified potential suppliers through internet search. We approached suppliers of the following technologies:

- Onshore wind (both new and second hand)
- Solar PV (commercial)
- Solar thermal (domestic)
- Combined heat and power (CHP)
- Battery storage (utility scale)

For each, we asked them the following:

- Purchase cost of technology “per unit” (e.g., per wind turbine, per solar panel)
- Estimate of installation cost (including transportation to Alderney) and practicalities of installation
- Estimate of annual maintenance requirements and how this translates to annual OPEX
- Estimated product lifetime
- Estimates of conversion efficiency/losses
- Cost and efficiency of converter/inverter used to connect to the grid
- Technical specification as available (e.g., data sheets)

From this exercise we ascertained the present-day costs and performance characteristics of the technologies, which were then used for the modelling exercises. The final suppliers that we interviewed can be found in Appendix 4

2.3 Electricity system modelling

2.3.1 HOMER

We used HOMER Pro software to simulate the Alderney electricity network. This software is supplied by UL, a global company who provide services in safety and certification[1]. HOMER (Hybrid Optimization of Multiple Energy Resources) is analytical software which allows microgrids to be simulated by balancing a required load with the energy generation available on the grid. Supported energy generating technologies include diesel generators, wind turbines, solar PV and hydro run-of-river. It supports both AC and DC loads and generation. The user can also specify energy storage on

[1] https://www.ul.com/about

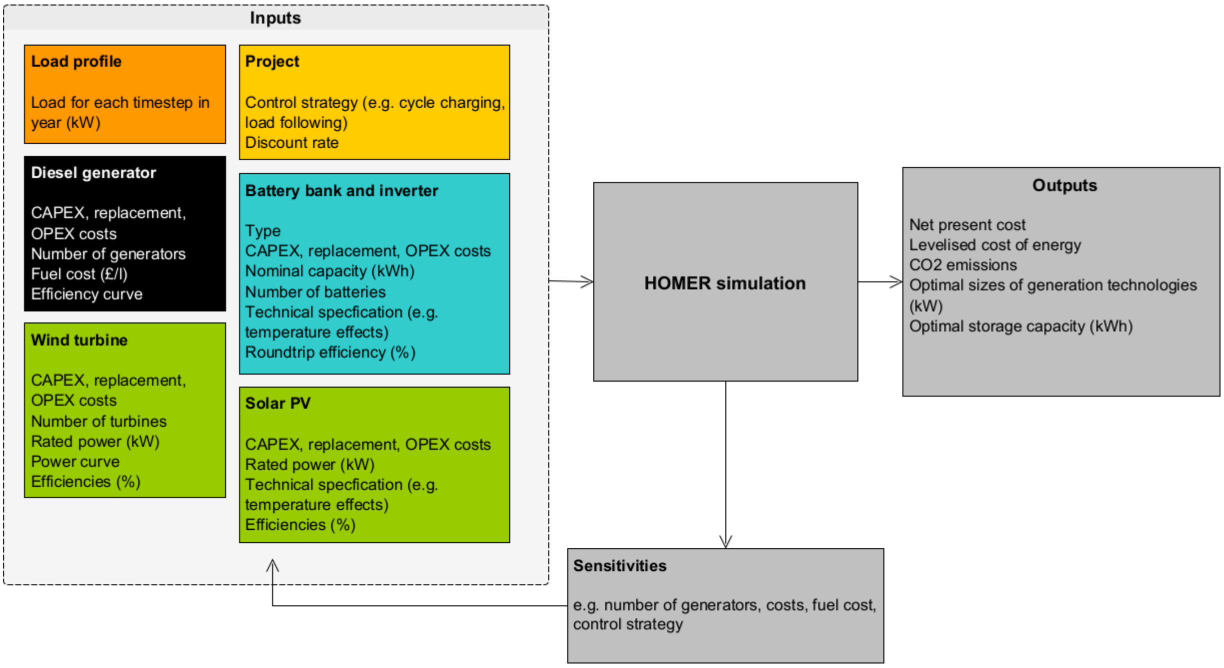

Figure 2 – Input and output of the HOMER simulation.

the network, including various battery types (such as lead acid, lithium ion and flow), flywheel and pumped hydro.

Figure 2 shows the main inputs and outputs of the HOMER software. The model simulates the electricity network using a time-step base approach. The model iterates through a year of data, timestep by timestep (typically hourly or half-hourly) and attempts to supply the load requirements with the available generating technologies at each step. The model optimises the various energy flows to minimise the overall levelized cost of energy (LCOE) of the whole system, with several different control strategies available. The output of the model is cost and details on the various technology combinations, as specified by the user (e.g., rated capacity and fuel consumption). It also gives information on the amount of CO2 produced.

2.3.2 Model setup: short term scenario

Demand profile

The island electricity demand (load profile) was provided by AEL. This was an hourly timeseries for the year 2013 and stated to be representative of current annual island energy usage. This is visualised in Figure 3 .The peak load was 1,252 kW and the mean 788 kW, with an average energy usage of 18.9 MWh/day. This was consistent throughout the year. This is mainly because domestic heating systems on the island are predominantly fuelled by heating oil rather than electricity.

Electricity generators

Within the model we investigated combinations of several generating technologies. These are summarised in Table 2 below. Costs were obtained from interviews with suppliers, with AEL providing operational costs for the diesel generators.

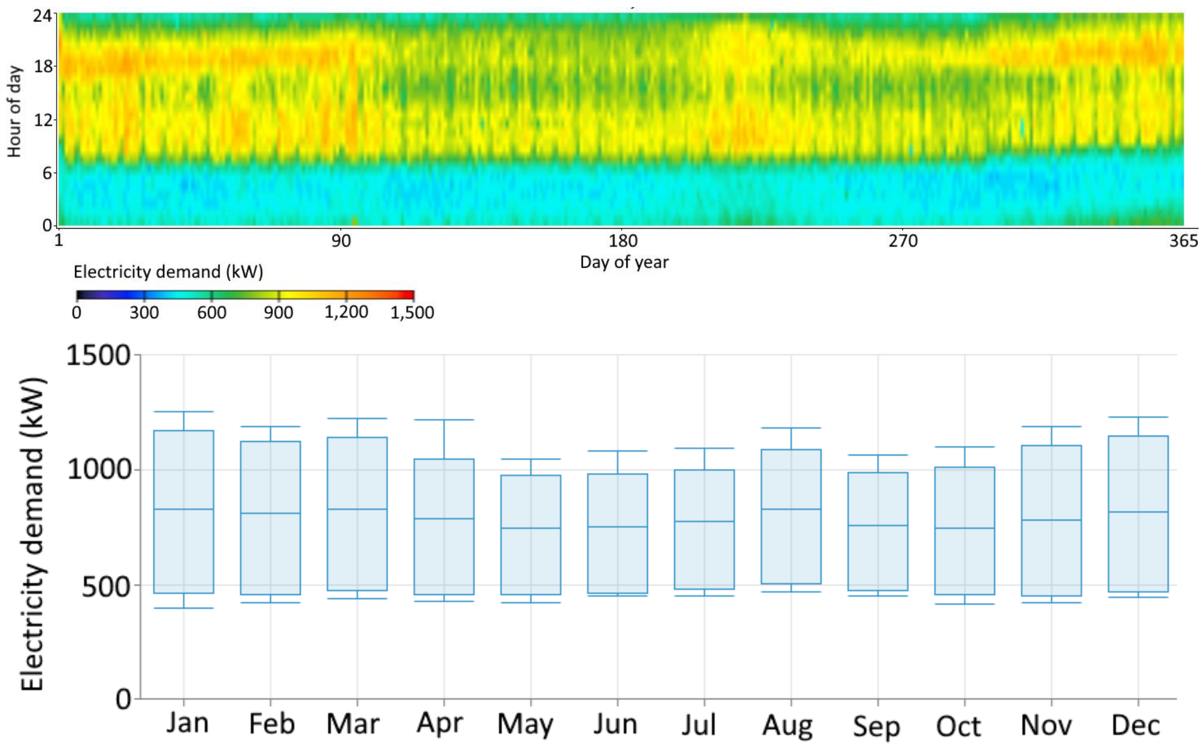

Figure 3 – 2013 electricity demand on the island. Top: visualised as a colour map. Bottom: monthly demand.

While AEL own eight generators, they only run between 1-4 engines at any one time with the others remaining on standby as 100% backup. We are modelling the actual electricity generation setup, not the backups which only kick in in emergency situations. Hence, we implemented four generators in the HOMER model. Generator CAPEX was set to zero, as AEL already own and operate the generators. CAPEX for the renewable technologies includes installation and contingency costs.

Two onshore wind turbine types were considered:

- A new wind turbine, the WES250. This is a 250 kW turbine produced by Dutch supplier Wind Energy Solutions (WES) [2]. It is two-bladed, with a rotor diameter of 30m and typically deployed on towers from 30-48m height.
- A refurbished wind turbine, a Vestas V52. This turbine is rated at 850 kW. The supplier we spoke to was Distributed Generation Ltd (DistGen) [3], who installed a similar turbine on Westray Island, Orkney in 2014. DistGen's business model is to install turbines for farmers and landowners and sell the electricity via a power purchase agreement (PPA) or similar.

The solar panels were considered in 250 kW "farms", up to installed capacities of 1,000 MW. These sizes are suitable for the current Alderney grid (with a 5 MW limit on new capacity) and were judged to be a good balance between providing meaningful renewable capacity at reasonable CAPEX levels.

[2] https://windenergysolutions.nl/ (accessed 08/02/2022)

[3] http://www.distgen.co/ (accessed 08/02/2022)

Table 2 – The electricity generating technologies considered for the Short-term scenario.

Technology	Model	Rated power per unit (kW)	CAPEX per unit (£k)	Annual OPEX per unit	Quantity range	Data sources
Diesel generator	Perkins 2806C-E18TAG	500	0	£5.80/operating hour	4	[6], [7]
Wind turbine	WES250 (new)	250	524	£5000/turbine	0-2	From supplier (WES)
	Vestas V52 (refurbished)	850	1,054	£42,000/turbine	0-2	From supplier (DistGen)
Solar PV	RSM120-8 (Risen Energy)	250	193	£2200/farm	0-4	From supplier (Solar Southwest)

Energy storage

Lithium-ion technology was chosen for energy storage, as it is the most commonly considered for grid applications. While flow batteries could become the technology of choice, the technology is currently still expensive and has not seen widespread deployment.

We used HOMER to optimise the storage capacity, which it determines from the generating technologies and associated energy production. We considered system sizes from 0-1,500 kWh, in 100 kWh increments, at a cost of £700/kWh, again this system size is deemed reasonable for the Alderney electricity demand.

Scenarios

Using HOMER, we analysed different combinations of renewable technologies to establish the most promising options for Alderney in reaching its strategic energy system objectives. We also wanted to compare the renewable technologies directly, to indicate which could be more economic at a smaller scale in the short term. These scenarios are summarised in Table 3.

- Scenario 1 is the current electricity system, being modelled as up to four 500kW generators in HOMER
- Scenarios 2-4 assess the impact from installing a small amount of renewables on the grid. They compare new wind turbines, refurbished wind turbines and solar PV, as previously described in *Table 2* above. The impact of energy storage is also assessed.
- Scenarios 5 and 6 consider a high penetration of renewables on the system, with the specific generators optimised by HOMER. Scenario 6 includes energy storage, with the actual battery sizing optimised by HOMER.

Table 3 – Scenarios examined. Dark green: technology implemented. Light green: technology considered, HOMER optimised for lowest system cost. White: technology not considered.

Scenario name	Diesel generators	Wind turbines – WES250	Wind turbines – V52	Solar farms	Battery storage
1. Current					
2. Early new wind					
3. Early refurbished wind					
4. Early solar					
5. High renewable					
6. High renewable with battery					

2.3.3 Model setup: medium term scenario

For the medium-term scenario (10-20 year timeframe), we modelled the case where Alderney decide to expand on their onshore renewable energy portfolio. Onshore wind and solar PV are both commercially mature technologies. As such, we anticipate that they could provide the most cost-effective solution in the medium term, prior to full commercialisation of hydrogen and in the absence of an interconnector (which would be a large and costly infrastructure project, discussed more in Section 4.4.3).

We modelled combinations of the following technologies, assuming a commissioning date of approximately 2035:

- **Onshore wind**: We again considered refurbished turbines, assuming that there is still a marketplace for these preowned wind turbines. The refurbished turbine model available ten years in the future is likely to be different, however the specifics are unknown. Because of this we modelled the refurbished V52 Vestas turbine again, assuming that the future turbine would be similar in dimensions and properties (as this turbine size seems appropriate for Alderney).

  We assumed a 10% reduction in CAPEX and OPEX. This comes from general innovations and the prior learning from installing turbines previously on the island. While some sources suggest greater cost reduction than this is possible, for example 35% by 2035, this is for new technologies (not refurbished technology) and about 45% of the reduction is expected to be due to increasing turbine size [8] which we do not envision for Alderney.

- **Solar PV:** We also reduced the costs of these systems, reducing CAPEX, replacement and OPEX by about 33%. This matches cost reduction projections published by the US National Renewable Energy Laboratory (NREL) in their 2021 Annual Technology Baseline (ATB) [9]. The cost reduction is assumed greater than wind because we assume new technology, benefitting from the latest innovations, and the cost reduction is not benchmarked to the panel size (unlike wind, where a lot of cost reduction is due to the wind turbine size increasing).

We also improved the solar panel derating factor in HOMER from 80% to 90% (performance difference from idealised manufacturer specification), modelling the increase in panel efficiency which is expected over this time period.

- **Battery:** We assumed that a larger commercial battery system would be required to maintain grid stability, after demonstrating feasibility in the short term scenario. We spoke to battery supplier Tesvolt[4], who provide battery storage systems which can be paired with solar farms to provide consistent output. They suggested a supply cost of £500/kWh, with a 20% premium for installation and commissioning, so we modelled the total CAPEX at £600/kWh. We assumed an O&M cost of 1% of CAPEX per year, in line with solar estimates.

  Tesvolt suggested that systems of their modular TS-I HV 80 would be most appropriate, with a nominal capacity of about 85 kWh. These can be installed in strings within cabinets, or within a larger shipping container for total storage capacities approaching 1 MWh.

  The costs outlined above are considering present day systems. The costs of batteries and the rare earth materials required are uncertain into the future. Our contact at Tesvolt implied that increased demand from applications such as electric vehicles might not necessarily lead to the reduction in battery costs that many foresee. For this reason, we kept the £600/kWh cost assumption as the baseline and considered a lower battery cost sensitivity scenario. Was reduced all costs by 50%, matching the projections of NREL in their 2021 ATB projection [10].

- **Diesel**: We reduced the generators on the system from four down to “a maximum of three”, allowing HOMER to optimise this considering the other renewables on the system. We assumed the same diesel price of £0.56/litre for the baseline. We also modelled a sensitivity of ±20% on diesel price to see how this impacted the system LCOE and optimal renewable technology capacities.

As well as changes in these technologies, we also reduced the project WACC: from 6.5% in the short term down to 5%. This reflects the greater commercial maturity in these microgrid renewable energy systems and is in line with other studies. For example, Goldman School of Public Policy assumed a 5.5% WACC case in their report examining renewable energy technologies in 2035 [11].

Scenarios

Again, we used HOMER to model this case. As this timeframe is more uncertain and far into the future, we decided to utilise HOMER’s optimisation algorithm more heavily. This suggests the optimal system configuration for the load profile and wider system costs specified.

We assumed the following caps on the technologies, to keep the upfront CAPEX to a reasonable level:

- Onshore wind: 0 to 5 turbines (0- 4.25MW)
- Solar: 0 to 4MW

[4] https://www.tesvolt.com/en/ (accessed 15/02/2022)

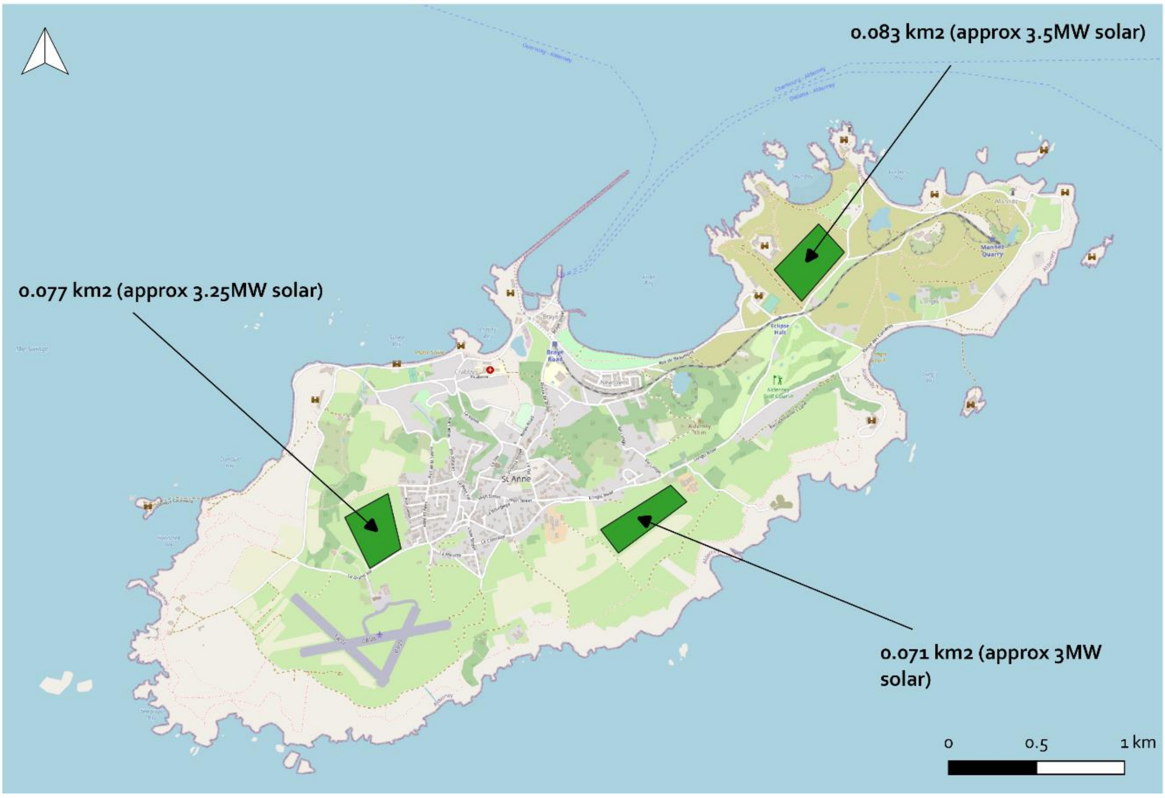

Figure 4 – Approximate solar farm scale compared to Alderney. This is just illustrative, to show how much room would be taken up by a 3-4MW solar farm.

- Battery: 0 to 25 battery banks (0-2.125MWh)
- Diesel: 0 to 3 generators (0-1MW)

Figure 4 indicates the scale of solar capacity compared to the size of Alderney. We believe that over 4MW of solar could be installed on the island (not including rooftop space suitable for domestic PV), but 4MW is chosen as the upper limit as we anticipate the benefits tailing off above this due to grid constraints. Consideration as to the impact on the character of the island would need to be considered by SoA.

2.4 Heating system modelling

An excel model was constructed which used three examples of house types on Alderney as a means of examining the economic feasibility of moving part of the housing stock on Alderney from 100% oil-fired heating to either of the following:

- Oil-fired heating with solar thermal (ST) assistance to reduce kerosene usage when meeting hot water demand.
- Fully electric heating via the use of air source heat pumps (ASHP) to meet both annual space heating and hot water demand.

For fully electric heating via ASHPs, the economic feasibility is of such a system is assessed with and without the effects of improved insulation. The effects of improved insulation in this instance are measured by reducing each house type's heat demand in 10% increments and observing the effect that this has on the payback period of each ASHP installation in discussion.

2.4.1 Model setup

Information on the house types used were extracted from the annex section of the Energy Saving Trust's publication Supporting the Development of the States of Alderney Island Energy Policy [12]. Below in Figure 5, Figure 6 and Figure 7, key details of each house type are presented.

Property type	**Pre 1900 3 Bedroom Detached**
Floor Area	95 sqm
Floor Type	Suspended timber
Wall	Granite Solid Walls
Roof	Pitched, loft conversion no insulation
Heating System	D-rated Oil fired Central Heating
Windows	Double Glazed Wooden pre 2002
SAP rating	G
Space heating	33,686 kWh
Secondary heating	2,470 kWh
Water heating	4,387 kWh
Pumps and fans	230 kWh
Lighting	586 kWh
Annual oil costs	£2,896
Annual electricity costs	£1,024
Total annual heating and lighting costs	£3,920

Figure 5 – House Type 1, Pre 1900 3 bedroom detached [12].

Property type	**1980s 3 Bedroom Bungalow Detached**
Floor Area	50 Sqm
Floor Type	Uninsulated concrete
Wall	Uninsulated cavity walls
Roof	Pitched roof 25mm loft insulation
Heating System	Oil fired Central Heating
Windows	Double Glazed Wooden pre 2002
SAP rating	E
Space heating	11,578 kWh
Secondary heating	849 kWh
Water heating	5,661 kWh
Pumps and fans	230 kWh
Lighting	348 kWh
Annual oil costs	£1,311
Annual electricity costs	£445
Total annual heating and lighting costs	£1,756

Figure 6 – House Type 2, 1980s 3-bedroom bungalow detached [12].

Property type	Early 1900s 3 bed end terrace
Floor Area	86 Sqm
Floor Type	Suspended timber
Wall	Granite Solid Walls
Roof	Pitched roof 25mm loft insulation
Heating System	Oil fired Central Heating
Windows	Single glazed wooden windows
SAP rating	E
Space heating	21,671.00 kWh
Secondary heating	1,926 kWh
Water heating	3,510 kWh
Pumps and fans	230.00 kWh
Lighting	546.78 kWh
Annual oil costs	£1,915
Annual electricity costs	£600
Total annual heating and lighting costs	£2,516

Figure 7 – House Type 3, Early 1900's 3-bedroom end terrace [12].

Despite each house type considered having a small portion of their heat demand met via a form of secondary heating (e.g., a log burner), these were negated from this set of heat modelling calculations. Instead, this modelling focuses on the annual oil (kerosene) consumption that is required to meet each house type's respective space heating and hot water demand.
The oil-fired boiler used in house type 1 is D-rated which indicates it is of a lower efficiency than the boilers used in house types 2 and 3. In this modelling it was acknowledged that each boiler's efficiency had already been taken into account to calculate the final annual oil costs for each house type.

To assess the cost feasibility of installing ST and ASHP on each house type on Alderney, the cost of kerosene and electricity on Alderney was established, where the unit cost of kerosene came to 78.73p/litre [2], and the unit cost of electricity 33.7p/kWh as part of the island's domestic two-part tariff (this includes the current 15.2p/kWh fuel cost component). The two part-tariff includes a fixed quarterly standing charge of £7.25 per room for up to six rooms, with the next 4 rooms charged at £5.46 per room [13]. For this cost modelling, the standing charges were negated due to the number of rooms in each home not being something that could be determined with a degree of certainty. To calculate how many litres of kerosene is consumed by each home per annum, the number of kWh per litre of kerosene was obtained at 10.35/kWh/litre [14]. From this figure, the annual kerosene consumption of each house type could be calculated and is shown below in Table 4.

Table 4 – House Types 1-3: annual kerosene consumption

Kerosene Consumed – House Type 1 (Litres/Annum)	3,678.55
Kerosene Consumed – House Type 2 (Litres/Annum)	1,665.60
Kerosene Consumed – House Type 3 (Litres/Annum)	2,432.95

With the cost of kerosene and electricity obtained, and the annual kerosene consumption of each house type now known, the cost of purchasing and installing a ST or ASHP system for each house type was estimated. From this, the annual cost savings and payback period of each installation could be calculated, with and without the effects of improved insulation.

2.4.2 Solar thermal

Through data received through engagement with a ST installer, we estimate that approximately 60% of annual hot water demand can be met through an appropriately sized ST installation. The same installer informed us that the estimated purchase and installation cost of a ST system for a larger three-bedroom home was £5,000, whereas the purchase and installation of ST for a smaller three-bedroom home is around £4,000. For this cost modelling, based on the floor area of each house, house types 1 and 3 were seen as larger three-bedroom homes with purchase and installation costs totalling £5,000, whereas house type 2 was seen as a smaller three-bedroom home with purchase and installation costs totalling £4,000. An additional 15% was applied to each homes purchase and installation cost to account for transport and additional labour costs if trained installers are required to travel to Alderney to set up each installation. The results are discussed in Section 3.1.3.

2.4.3 Air source heat pump (without insulation)

Compared to ST, more factors need to be considered when assessing the economic feasibility of ASHPs. One of the most important factors in making ASHPs economically feasible is their coefficient of performance (CoP) which is a measure of how many kWs of useful thermal energy can be extracted from ambient air for each kW of electrical input. In other words, if an ASHP can extract 3 kW of thermal energy using 1 kW of electrical input, the ASHP has a CoP of 3. This is demonstrated in Equation 1.

Equation 1

$$CoP = \frac{ASHP\ Thermal\ Output\ (kW)}{ASHP\ Electrical\ Input\ (kW)}$$

However, as the temperature of ambient air changes from day to day throughout the year, the CoP will also change. Therefore, seasonal performance factor (SPF) is used to calculate annual cost savings through the use of ASHP. The SPF is the average CoP of a heat pump over the heating season, which in most cases will be the winter months (October to March). For these calculations a SPF of 3.2

was applied. This was chosen because ASHP SPF will typically range between 2.9 and 3.5 in the UK when used to cover both space heating and hot water demand, as shown in Figure 8 [15].

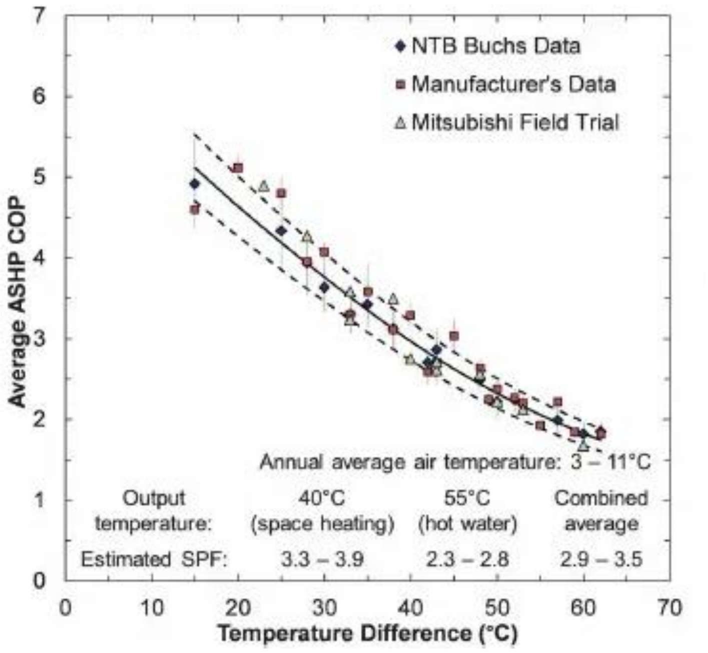

Figure 8 – Air source heat pump: typical UK seasonal performance factors [15].

To find the corresponding average heat demand required at each house, the number of hours in which each ASHP operated per annum needed to be determined. Here it is assumed that each ASHP operates on average 8 hours per day between October and March (182 days) which results in 1,456 hours of operation per annum. By dividing each house type's heat demand by 1,456 the average heat demand can be found, as shown in Equation 2.

Equation 2

$$Average\ Electrical\ Demand\ (kW) = \frac{Average\ Heat\ Demand\ (kW)}{Seaonal\ Performance\ Factor}$$

With the average corresponding electrical demand for each house now known, the annual electrical demand is found by multiplying by 1,456 (annual hours of ASHP operation), as shown in Equation 3.

Equation 3

$$Annual\ Electrical\ Costs\ (£) = Annual\ Electrical\ Demand\ (kWh)\ x\ Unit\ Cost\ of\ Electricity\ (£)$$

To find each house type's cost savings, the annual running costs of using a kerosene boiler are subtracted from the annual running costs of using an ASHP, as shown in Equation 4.

Equation 4

$$Cost\ Savings\ (£) = Annual\ Kerosene\ Costs\ (£) - Annual\ Electrical\ Costs\ (£)$$

To estimate the payback period of each ASHP installation, the purchase and installation cost of each system needs to be calculated. With each house type having differing heat demand, insulation quality, and floor area, the electrical capacity of the ASHP installed in each home will also differ. Because there are so many other factors that determine ASHP sizing in a home such as the number of occupants, household consumption patterns, etc, the correct size of ASHP for a given property would have to be determined by a reputable installer. For this modelling work, information on each house type was entered into the Mitsubishi Ecodan selection tool which considers property type, property age, current means of heating, number of bedrooms, and whether the home in question is insulated [16]. From this it was recommended that without cavity wall or equivalent insulation, house types 1, 2, and 3 should use 11.2 kW, 5 kW, and 8.5 kW Mitsubishi Ecodan AHSPs respectively [17], [18], [19].

In addition to the ASHP, a water cylinder (costing £1,982) and Ecodan controller (£857) will also need to be installed at each property to provide sufficient hot water storage and adjustment of each ASHP's settings (the costs of these can be found in Ref [17]). For this study it is assumed that 4 people occupy each dwelling so a 170-litre water cylinder was selected. When selecting water cylinders, it is recommended to allow 40 litres per occupant per day, with a 170-litre cylinder being sufficient in doing so [20].

With all components of each ASHP system selected for each property, and the purchase cost of each system known, the installation cost of each ASHP had to be determined. For an air-to-water ASHP the average installation cost comes to £7,000 on the UK mainland [21]. For this study, it is assumed that transporting the ASHPs to Alderney adds 15% to that cost, with each ASHP's installation coming to £8,050. Figure 9 shows the total purchase and installation cost for ASHPs at each house type. Due to the tax laws on Alderney, VAT has been excluded from each of these purchases.

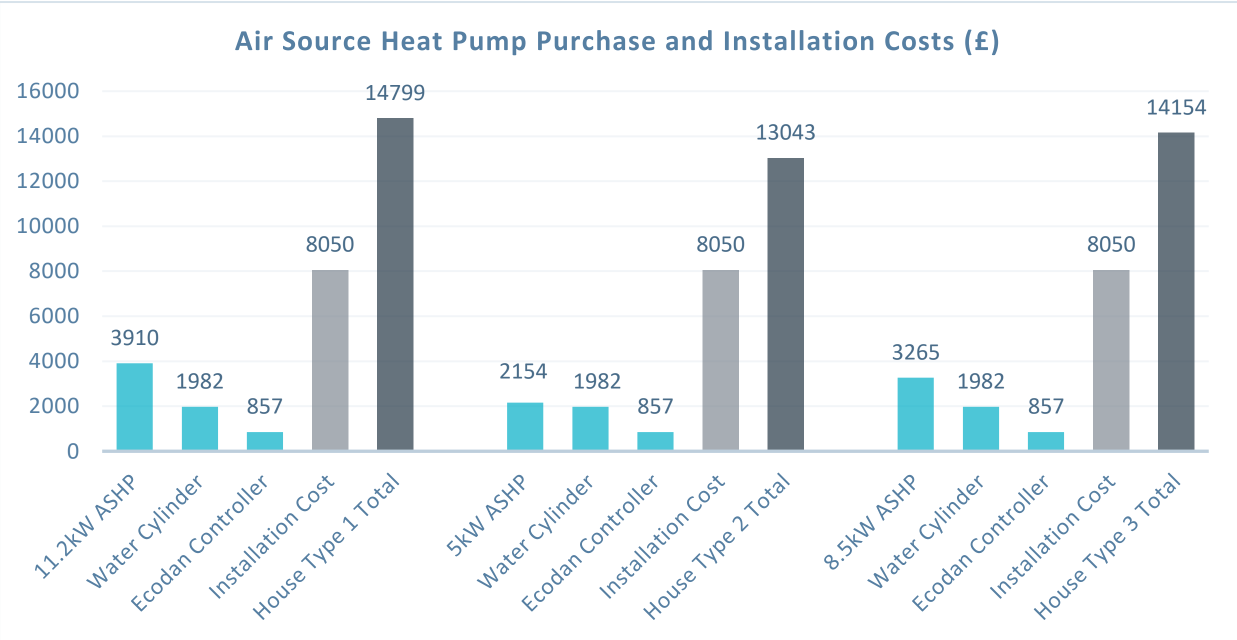

Figure 9 – House Types 1-3, Air source heat pump purchase and installation costs.

Using the cost of kerosene and electricity in Section 2.4.1 alongside ASHP purchase and installation costs in Figure 9, the annual cost savings and the payback period of each system were determined and is discussed in Section 3.2.2.

2.4.4 Air source heat pump (with insulation)

With improvements to the insulation quality of each house having the potential to drastically reduce the payback period of each ASHP system in discussion, the effects of insulation were assessed by reducing the annual heat demand of each house type from 100% to 40% in 10% increments. These calculations have not considered the upfront costs of insulation and merely serve to demonstrate the reduction in ASHP payback periods when different levels of insulation have been employed in advance.

2.5 Assumptions

Given the complexity of Alderney's energy system, several assumptions have been made to help define likely energy system scenarios as follows:

Summary of electricity system modelling assumptions:

- We assume that annual electricity demand is fixed (at 2013 level) for period of time modelled (15 years)
- We assume diesel price is fixed at £0.56/l for period of time modelled
- Costs of renewable technologies are as stated by suppliers we engaged with, with 20% premium to account for contingency (transport of components to Alderney, project management, etc.)
- Wind and solar yield estimates are made within the HOMER software using data from NASA's Prediction Of Worldwide Energy Resource (POWER) database [5].
- We have not considered the specific siting of the renewable technologies on the island. We arbitrarily selected a location of 49°43.5'N 2°10.9'W on the north side of the island for the purposes of the HOMER calculation, deemed representative of the renewable resources.
- We assume that no grid upgrades are required, and that grid integration cost is included within the data received from suppliers.

Summary of heat system modelling assumptions:

- 60% of annual hot water demand is met via the use of ST for each house type in discussion.
- Each ASHP installation in discussion has a seasonal performance factor (SPF) of 3.2.
- Each ASHP installation in discussion operates for 1,456 hour per annum.

[5] https://power.larc.nasa.gov/ (accessed 16/02/2022)

- Each house type in discussion has a maximum of four occupants and a 170-litre water cylinder for both ST and ASHP is deemed sufficient.
- Transport of ST and ASHPs to Alderney adds 15% to the purchase and installation cost of each respective system.
- Potential maintenance costs for ST and ASHP have been excluded. This is down to both systems being generally low maintenance.
- Each affordable measure to improve insulation on each house type takes a full day's labour which comes to £175 per day.

General assumptions

The specific planning and licencing requirements for the various energy technology solutions identified have not been considered and would need to be acquired by the relevant project developer. High level consideration of local constraints such as designated protected sites, vicinity to the airport, impact on the character of the Island were reviewed and deemed acceptable.

3 RESULTS & DISCUSSION

3.1 Short term scenario (0-10 years)

3.1.1 Overview

Within the next decade Alderney's fossil fuel reliant energy system will face a critical strategic decision point in relation to how the island imports the fuel it relies on for both electricity production and heating as a result of an ageing shipping fleet. This is further compounded by soaring global oil prices to which the island is vulnerable and which AEL has little choice but to pass on to consumers. As such this study has identified and analysed several different energy system scenarios seeking to partially remove the islands reliance on fossil fuels through means of renewable energy generation on the island. Critically, the study is mindful of upfront CAPEX cost requirements as well as the LCOE so as not to negatively impact already high energy costs on the island. The islands electricity system and heating system are predominantly uncoupled (one reliant on diesel the other on Kerosene oil) and as a result have been assessed independently of each other.

3.1.2 Electrical system

Table 5 shows the key results for the six scenarios examined. It shows both the technology capacities, as determined by HOMER (light green) or selected as input (dark green), and the associated results for each scenario. Table 6shows the changes in the key results for the renewable energy scenarios compared to the current system that was modelled.

Table 5 – Short term electricity system scenario results. Energy technologies: diesel generator (D), new wind turbine (WN), refurbished wind turbine (WR), solar PV (S) and battery storage (B). Light green capacities were devised as optimal from HOMER, dark green indicate chosen technology sizes.

Scenario name	Energy technologies					Key results					
	D	WN	WR	S	B	CAPEX	OPEX	Diesel consumed	Net present cost	LCOE	Renewable fraction
	MW	MW	MW	MW	MWh	£m	£k/yr	L (M)/yr	£m	£/MWh	%
S.1. Current	2	0	0	0	0	0.0	118	1.83	13.2	171	0%
S.2. Early new wind	2	0.25	0	0	0	0.5	112	1.58	11.9	155	14%
S.3. Early refurbished wind	2	0	0.85	0	0	1.1	138	1.13	9.9	128	40%
S.4. Early solar	2	0	0	0.25	0	0.2	117	1.75	12.9	167	4%
S.5. High renewable	2	0	1.7	0.25	0	2.3	159	0.82	9.2	119	57%
S.6. High renewable with battery	2	0	1.7	0.75	0.8	3.4	117	0.54	8.0	103	70%

Table 6 – Change in scenario key metrics compared to the current scenario (scenario 1). Red cells are negative impacts and green cells are positive benefits.

Scenario name	CAPEX	OPEX	Diesel consumed	Net present cost	LCOE
	£m	%	%	%	%
S.1. Current	0.0	0.0%	0.0%	0.0%	0.0%
S.2. Early new wind	+0.5	-5%	-14%	-10%	-10%
S.3. Early refurbished wind	+1.1	+17%	-38%	-25%	-25%
S.4. Early solar	+0.2	-1%	-4%	-2%	-2%
S.5. High renewable	+2.3	+35%	-55%	-31%	-31%
S.6. High renewable with battery	+3.4	-1%	-70%	-40%	-40%

Scenario 1: Current system

The current system was calculated to have an annualised OPEX of £118k per year for maintenance of the generators. This is within 20% of the £100k estimated by AEL. The system was calculated to consume 1.83 million litres of diesel, about 14% higher than estimated by AEL (see Table 1). We believe that this accuracy is reasonable and provides a realistic benchmark for modelling the renewable energy scenarios against.

Scenarios 2-4: Early-stage systems

The three early, small scale renewable energy scenarios (S.2, S.3, S.4) all reduce the LCOE of the system: from 2% for the 250kW solar farm up to 25% for the large, refurbished wind turbine. While the solar CAPEX is very low at about £200k for supply and installation of the panels, the energy production is relatively low, with only a 13.5% efficiency. This efficiency is fairly typical of solar panels in real world applications, and a larger quantity would be needed to provide meaningful energy contribution. Such a project could be a low-cost way of trialling integration of renewable energy onto Alderney's grid.

Figure 10 shows the LCOE of larger amounts of solar, up to 1MW installed capacity, in comparison to the wind turbine cases. Solar is the least preferred option, with a higher LCOE across the capacity ranges examined. This is because, while the CAPEX and OPEX are low, the efficiency is also low and so only a relatively small amount of electricity is generated. Despite the higher LCOE, the lower

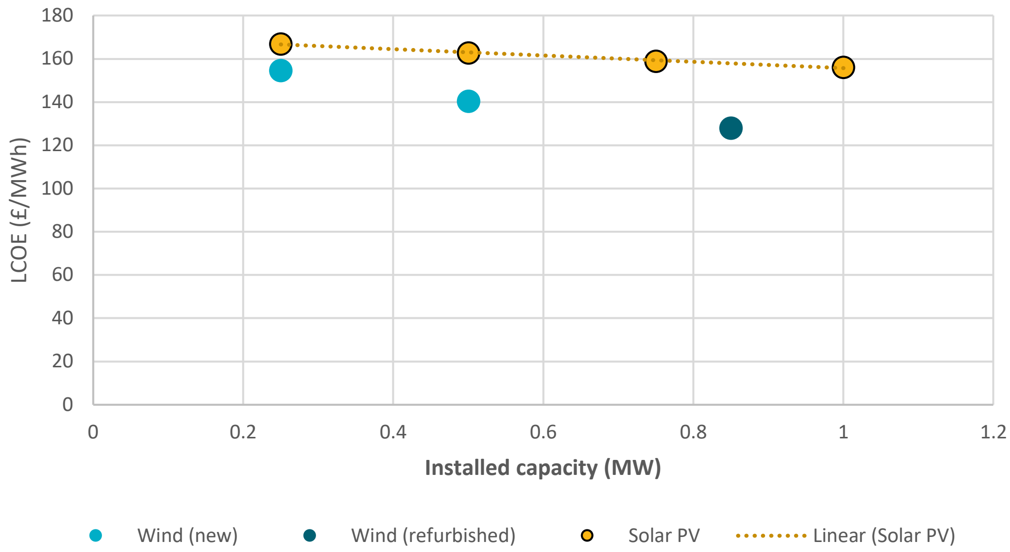

Figure 10 – LCOE of increasing solar capacity compared to the two wind turbine options (new and refurbished)

upfront CAPEX and lower maintenance requirements (and reduced complexity due to no moving parts) means that solar is still a viable option for Alderney. At 1MW, the solar farm would reduce diesel usage by about 15% per annum.

Comparing the two early wind scenarios (S.2 & S.3), the larger refurbished V52 turbine has a better cost of energy than the new WES250. This is largely to be expected, as the turbine is a lower cost per MW. The reliability and lifetime of the refurbished turbine are likely to be reduced compared to the new turbine, which we were unable to accurately model due to limited data, and so this is something that should be considered if purchasing a pre-owned turbine. While the refurbished turbine did increase the annual OPEX by about 17%, compared to Scenario S.1, this was more than counteracted by the 38% reduction in diesel. DistGen, the supplier of the preowned turbine that we spoke to, stated that they would prefer to have ownership of the turbine and negotiate a PPA with States of Alderney. This would mean no upfront CAPEX payment or regular OPEX expenses would be incurred by AEL, however could result in greater money paid out over time through the feed in tariff (FiT) offered. This arrangement could not be modelled in HOMER, and so is discussed in more detail in Section 4.1.4.

Scenarios 5 & 6 – Larger scale renewable energy

Scenarios S.5 and S.6 show the greatest reductions in LCOE, at 33% and 42% respectively. The optimal system in both cases was found to use two refurbished 850 kW wind turbines, supported by a small amount of solar. Both scenarios also showed large reductions in the diesel required: 55% for Scenario S.5 and 70% for Scenario S.6. This equates to a fuel cost saving of about £600-700k per year, a significant amount which could be reinvested by the island or allocated towards future large scale energy system purchases (e.g., an interconnector).

Scenario S.6 found an 800 kWh battery to be the optimal solution, with an associated CAPEX cost of £560k. While this is a large amount, the battery would also help to support the grid, helping to maintain grid frequency in the presence of the variable renewable energy sources. Thus, we believe that for this scale of system battery storage would be a crucial component to prevent grid instability with such a large amount of renewables on the grid.

While the LCOE and net present cost of these systems is lower, the upfront capital cost is significant: at £2.3m and £3.4m for Scenario S.5 and S.6 respectively. This would represent a large investment for the island.

Summary

Figure 11 shows the LCOE and renewable energy % of the six scenarios. Scenario 2 (early new wind) and Scenario 4 (early solar) only marginally decrease the LCOE and provide a small amount of renewable capacity. This contracts with the other three scenarios, which provide much more meaningful LCOE reduction and renewable energy levels.

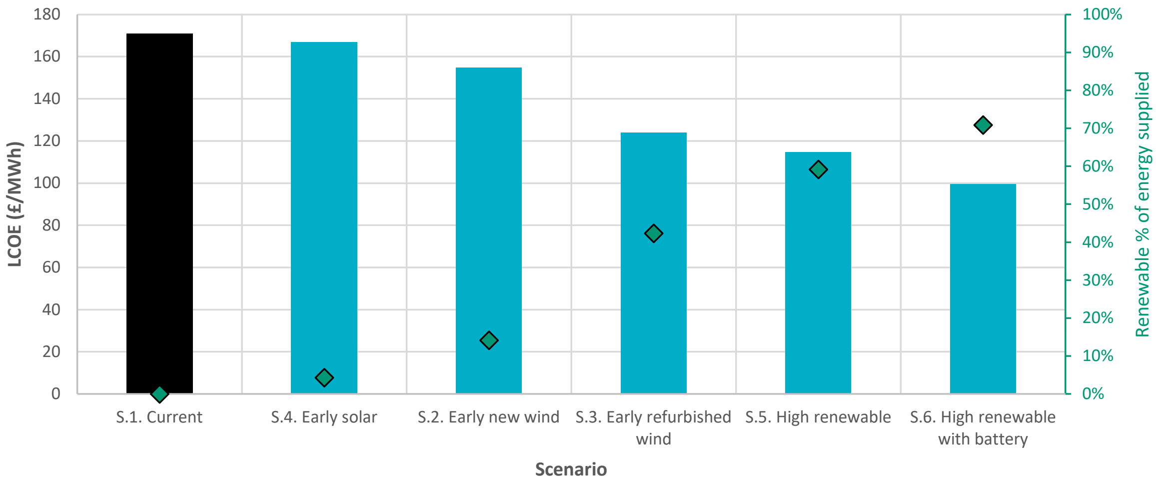

Figure 11 – Scenarios ranked by LCOE, in descending order, along with the percentage of renewable energy supplied.

Figure 12 shows the trend in LCOE vs upfront CAPEX for the six scenarios, along with a linear trendline. This trend decreases, showing a proportionality between the upfront capital spent and the long-term reduction in LCOE that is seen. A notable divergence is seen for Scenario 3, which is quite far below the linear trend. This indicates that this scenario is good value for money, with a relatively low CAPEX compared to the LCOE saving that is seen. For example, comparing Scenario 3 with Scenario 5: Scenario 5 costs 118% more (more than double) but only reduces LCOE by 7%. This shows that a good, initial option for the island would be to install a larger, refurbished turbine, as this would have a relatively large impact on overall lifetime system cost for a modest CAPEX outlay.

Refurbished turbine PPA arrangement

Considering Scenario S.3, a refurbished turbine could save about 700,000 litres of diesel every year. At today's diesel price of £0.56 per litre, this would result in a cost saving of almost £400k per annum. If SoA/AEL financed the turbine then this cost saving could effectively be banked, minus the turbine OPEX, however it would mean that the Island would have to fund the approx. £1m capital cost, and hold some responsibility for turbine maintenance.

An alternative arrangement could be to offer a feed in tariff via PPA or similar to a private company for the electricity generated. The private company would fund the CAPEX, likely allowing the deployment to be accelerated, and be responsible for maintenance. This would also ease the

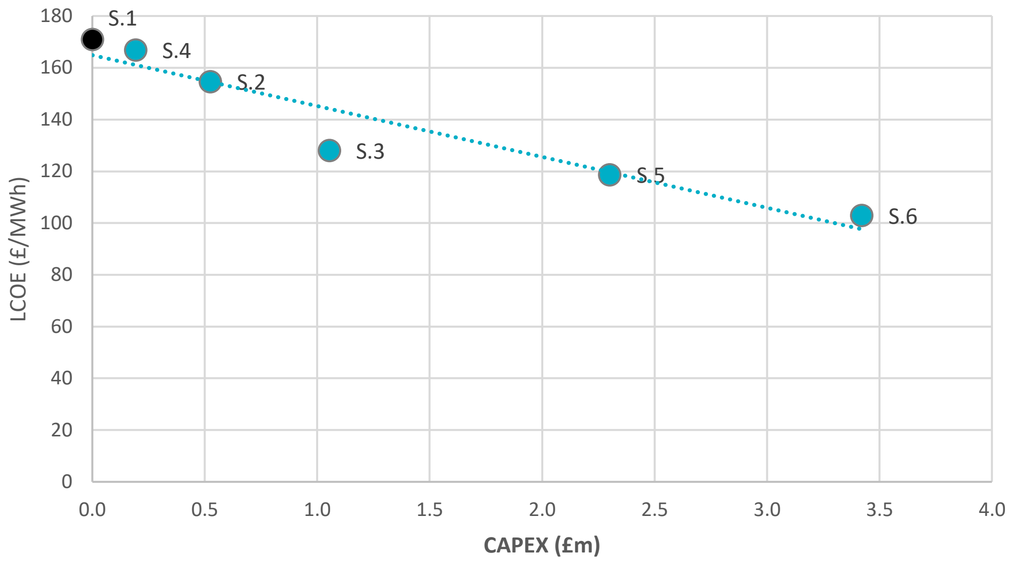

Figure 12 – LCOE vs CAPEX trend for the six scenarios

administrative burden for Alderney once the turbine is operational.

Based on the £400k expected cost saving, we believe that an appropriate PPA to offer would be £50-60/MWh. This is based on the following assumptions:

- Diesel cost of £0.56/l
- V52 wind turbine capacity factor of 42.7%, as calculated by HOMER, with 3,180 MWh/yr produced
- 700,000 litres of diesel saved per year due to the wind turbine, as calculated by HOMER (equivalent to £390k cost saving per year).
- Turbine CAPEX of about £1.05m; OPEX of £42k per annum. These were both indicated by DistGen based on their previous project experience.

Our calculation assumes that AEL would retain about £200k of the diesel cost saved, with the rest effectively offered as the PPA. Assuming a PPA of £61.4/MWh, this would result in an IRR of 10.7% for the developer, with the developer expecting about £200k per year in revenue. This level would both be attractive to the developer (as typical IRR for renewable projects is about 9-10% [8]) and also for Alderney, as it would allow some of the diesel cost savings to be retained and used for other initiatives (e.g., to lower consumer energy bills or invest in new projects).

Figure 13 shows the variation of diesel cost saved by Alderney and developer IRR against the FiT. An IRR of 5-10% would be necessary to develop interest from a private company. This level, as indicated by the hatched area on the figure, would be equivalent to a FiT of £50-60/MWh. This would allow Alderney to retain £200-235k per year from fuel cost savings minus the amount paid out through the FiT.

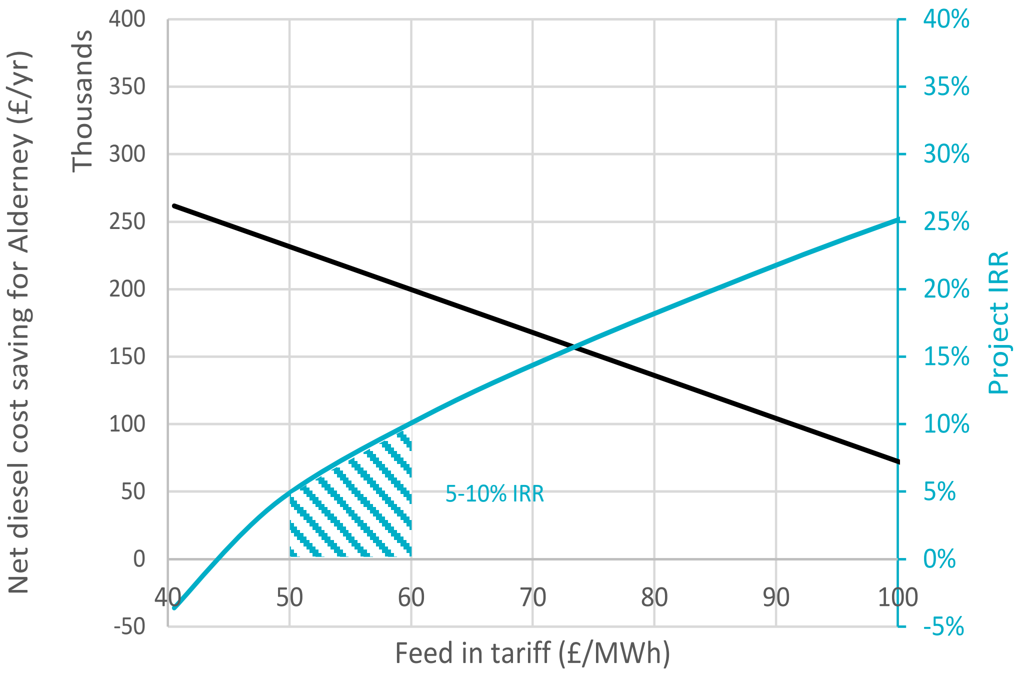

Figure 13 – Cost saving for Alderney (due to lower diesel consumption) and IRR to wind turbine developer vs feed in tariff (FiT). This assumes a diesel price of £0.56/l and that the turbine displaces 700k litres of fuel. The net diesel cost saving is the total

SoA could choose to put the PPA out to competitive tender, which could lead to the most competitive price. Equally, SoA could negotiate and agree this level with a company directly. The above calculations are tied to the projected turbine performance, as calculated within HOMER, and on the financial assumptions as presented (e.g., turbine CAPEX). We believe that the £50-60/MWh range is indicative but should be based on the technical specification and estimated performance of any agreed project once technical due diligence is established.

3.1.3 Heating system

In this section results are presented from cost modelling undertaken on Alderney's domestic heating systems. The cost savings and payback period of ST and ASHP systems on each house type are given before analysis into the economic feasibility of each solution is presented, with and without the effects of improved insulation. The cost of installing insulation measures which reduce each house type's heat demand by a given percentage are not considered in this analysis. However, costs are given for packages of measures which are deemed affordable for each house type. To conclude this section, analysis is given to determine how representative the example house types used in this modelling are of the wider housing stock on Alderney by measuring their kerosene consumption against Alderney's annual kerosene consumption for all purposes.

Solar thermal

As described in Section 3.4.2, the cost to purchase and install a ST system was estimated at £5,000 for a large three-bedroom home (house types 1 and 3), and £4,000 for a small three-bedroom home (house type 2). 15% was added to these costs to account for transport and additional labour costs associated with installing a ST system on Alderney. Below in Table 7, Table 8 & Table 9, the annual cost savings and payback period of ST on each house type is shown.

Table 7 – House Type 1, Solar Thermal Cost Savings and Payback Period

House Type 1 - Solar Thermal Cost Savings and Payback Period	
Water Heating (kWh/Annum)	4,387.00
Solar Thermal Coverage	0.60
Solar Thermal Coverage (kWh/Annum)	2,632.20
Remaining Hot Water Demand (kWh/Annum)	1,754.80
Cost Savings (£/Annum)	200.23
Cost Savings (%/Annum)	6.91
Purchase + Installation (£)	5,750
Payback Period (Years)	28.72

Table 8 – House Type 2, Solar Thermal Cost Savings and Payback Period

House Type 2 - Solar Thermal Cost Savings and Payback Period	
Water Heating (kWh/Annum)	5,661.00
Solar Thermal Coverage	0.60
Solar Thermal Coverage (kWh/Annum)	3,396.60
Remaining Hot Water Demand (kWh/Annum)	2,264.40
Cost Savings (£/Annum)	258.37
Cost Savings (%/Annum)	8.92
Purchase + Installation (£)	4,600
Payback Period (Years)	17.80

Table 9 – House Type 3, Solar Thermal Cost Savings and Payback Period

House Type 3 - Solar Thermal Cost Savings and Payback Period	
Water Heating (kWh/Annum)	3,510.00
Solar Thermal Coverage	0.60
Solar Thermal Coverage (kWh/Annum)	2,106.00
Remaining Hot Water Demand (kWh/Annum)	1,404.00
Cost Savings (£/Annum)	160.20
Cost Savings (%/Annum)	5.53
Purchase + Installation (£)	5750
Payback Period (Years)	35.89

From the results in Table 7, Table 8 & Table 9, it can be seen that house type 2 benefits the most from the installation of ST. Referring back to Figure 5, Figure 6 and Figure 7, it can be seen that despite house type 2 having the lowest annual heat demand, it has the greatest annual hot water demand. Furthermore, with it being a smaller property than house types 1 and 3, the purchase and installation cost is lower, hence the shorter payback period. The ST installer that we engaged with stated that a ST system typically has a lifetime of around 20 years if kept in good condition and is checked for issues regularly. From this insight it can be determined that a ST system is only a worthwhile investment for house type 2, or for homes on Alderney in which a larger portion of their annual heating demand is taken up by hot water demand.

Air source heat pump (without insulation)

In Section 3.4.3, the estimated cost of installing an ASHP in each house type was presented in Figure 9. By using this information alongside assumptions detailed in Section 2.5, the annual cost savings and payback period of an ASHP system for each house type was calculated and is shown in Table 10, Table 11 & Table 12.

Table 10 – House Type 1, Air Source Heat Pump Cost Savings and Payback Period

House Type 1 - Air Source Heat Pump Cost Savings and Payback Period	
Heat Demand (kWh/Annum)	38,073.00
Annual Hours of Operation	1,456.00
Average Heat Demand (kW)	26.15
Seasonal Performance Factor	3.20
Corresponding Electrical Demand (Average) (kW)	8.17
Annual Electrical Demand (kWh)	11,897.81
Total Cost (£/Annum)	4,013.13
Cost Saving (£/Annum)	-1,117.01
Cost Saving (%/Annum)	-38.57
CAPEX + Installation (£)	14,799.00
Payback Period (Years)	N/A

Table 11 – House Type 2, Air Source Heat Pump Cost Savings and Payback Period

House Type 2 - Air Source Heat Pump Cost Savings and Payback Period	
Heat Demand (kWh/Annum)	17,239.00
Annual Hours of Operation	1,456.00
Average Heat Demand (kW)	11.84
Seasonal Performance Factor	3.20
Corresponding Electrical Demand (Average) (kW)	3.70
Annual Electrical Demand (kWh)	5,387.19
Total Cost (£/Annum)	1,817.10
Cost Saving (£/Annum)	-505.77
Cost Saving (%/Annum)	-38.57
CAPEX + Installation (£)	13,043.00
Payback Period (Years)	N/A

Table 12 – House Type 3, Air Source Heat Pump Cost Savings and Payback Period

House Type 3 - Air Source Heat Pump Cost Savings and Payback Period	
Heat Demand (kWh/Annum)	25,181.00
Annual Hours of Operation	1,456.00
Average Heat Demand (kW)	17.29
Seasonal Performance Factor	3.20
Corresponding Electrical Demand (Average) (kW)	5.40

Annual Electrical Demand (kWh)	7,869.06
Total Cost (£/Annum)	2,654.23
Cost Saving (£/Annum)	-738.78
Cost Saving (%/Annum)	-38.57
CAPEX + Installation (£)	14,154.00
Payback Period (Years)	N/A

From the results in Table 10, Table 11 & Table 12, it can be seen that with the current price of electricity on Alderney all three house types would have increased annual heating costs if ASHP's were to be installed. With the typical lifetime of an ASHP system being approximately 20 years [22], ASHP payback would have to fall below that timescale to ever be considered economically feasible. Therefore, without improvements to the insulation quality of each house type, ASHPs will remain an unviable domestic heating solution on Alderney.

Air source heat pump (with insulation)

With ASHPs being an unviable heating solution without improvements to the insulation quality of each house type, the effects of insulation were assessed to determine if this had the potential to make ASHPs an economically feasible heating solution on Alderney. As mentioned previously, the original heat demand of each property was reduced from 100% to 40% in 10% increments. The results which produced cost savings of any type are shown below in Figure 14.

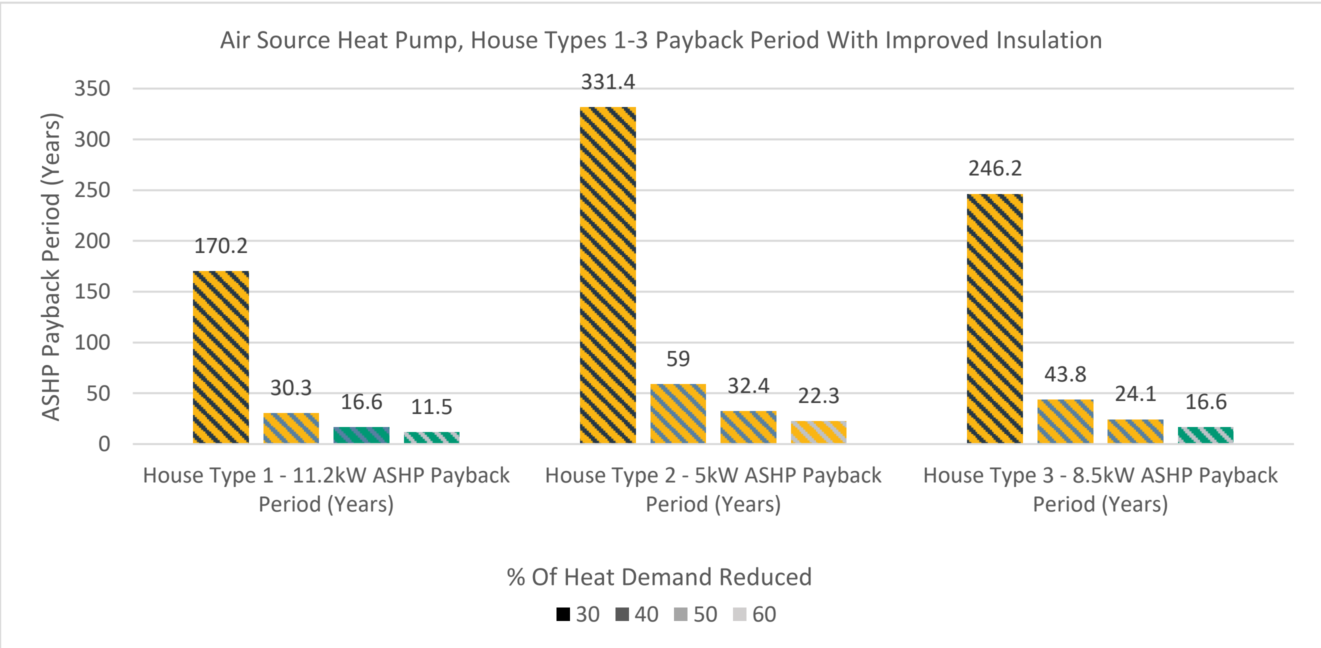

Figure 14 – Air Source Heat Pump, House Types 1-3 Payback Period with Improved Insulation. Yellow indicates payback is not achieved over the lifetime of the system. Green indicates payback is achieved over the lifetime of the system.

As can be seen in Figure 14, improved insulation reduces the ASHP payback period for all house types. However, the extent of insulation that is required to bring each ASHP's payback period to the point of economic feasibility (below 20 years) differs, with ASHPs never becoming economically feasible for house type 2 unless annual heat demand is reduced by over 60%. For house types 1 and 3, heat demand needs to be reduced by 50% and 55% respectively, with the extent of insulation required to enable such a heat demand reduction likely having significant cost implications of their own for all house types in discussion. Therefore, if the house types assessed are representative of the wider housing stock on Alderney, ASHPs are a highly unfeasible heating solution for the island.

Using the Mitsubishi Ecodan selection tool, it was found that improved insulation resulted in a smaller capacity ASHP being suitable in meeting the annual heat demand of house types 1 and 3, with an 8.5 kW and 5 kW ASHP being deemed sufficient for each respective household. Because of the lower purchase and installation costs associated with these smaller capacity ASHPs, the payback period is further improved as seen in Figure 15Figure 16.

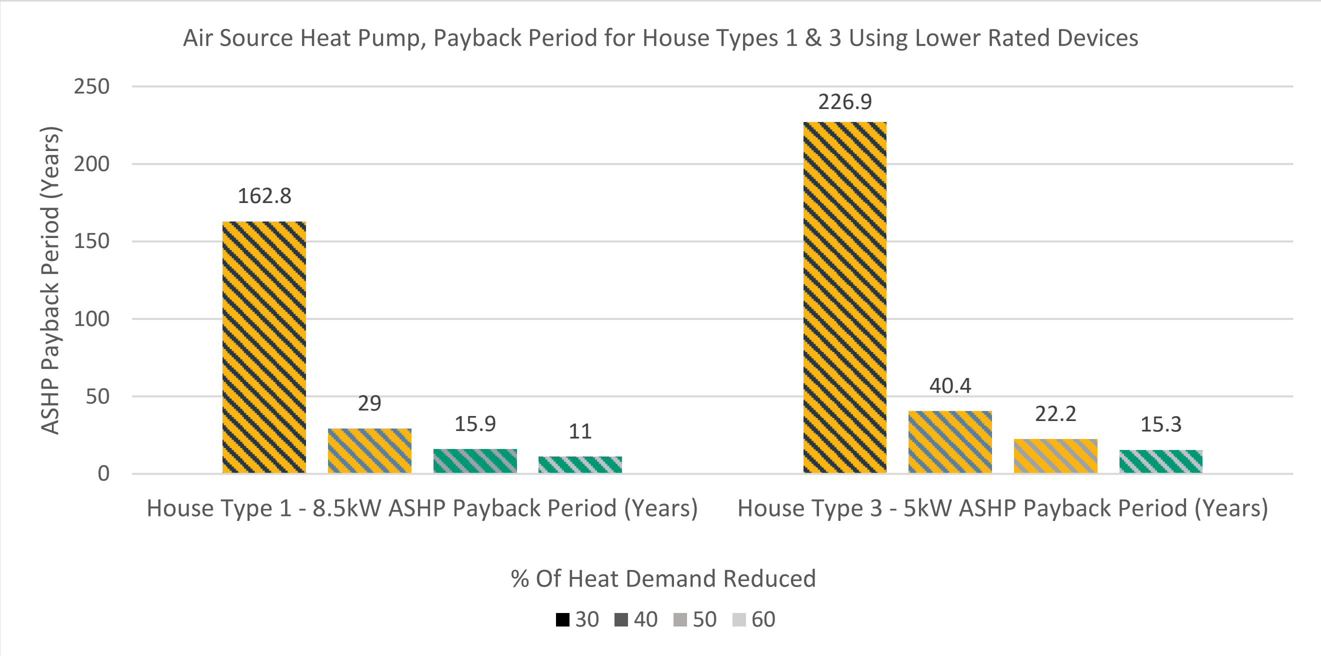

Figure 15 – Air Source Heat Pump, Payback Period for House Types 1 & 3 Using Lower Rated Devices. Yellow indicates payback is not achieved over the lifetime of the system. Green indicates payback is achieved over the lifetime of the system.

In Figure 15Figure 16 a slight improvement is shown in ASHP payback period for house types 1 and 3 when switching to a smaller capacity device. However, the extent of insulation that is required to make these ASHPs economically feasible remains unaffected.

With reference to house type 2 which performed the worst in terms of ASHP payback, one of the mains reasons for this is relatively low heat demand in comparison to the two other house types, and the fact that the purchase and installation cost of a 5 kW ASHP system is not much less compared with a system rated at 8.5 kW or 11.2 kW. Furthermore, due to house type 2 having a higher proportion of its overall heat demand consisting of hot water demand, it is likely it would achieve a lower SPF than the other house types due to the higher temperatures required for water heating compared to space heating [15]. Yet again, ASHPs remain a highly unfeasible heating solution for Alderney is these house types are indeed representative of the island's wider housing stock.

Affordable Insulation Costs

Referring back to the EST publication in Ref [12], packages of measures were recommended that would save each house type money on energy bills in the long-term, with insulation being a consistent recommendation. Solid wall insulation was recommended as one of the measures to improve energy efficiency in house types 1 and 3, with both houses currently having uninsulated granite walls. However, solid wall insulation was costed at £9,600 and £7,200 respectively. In cases where solid wall insulation is required to reduce heat demand substantially, it may only be feasible to proceed with improved insulation alone due to the cost constraints faced by both residents and the SoA. However, this will still result in annual cost savings and reduced kerosene consumption on Alderney. If sizeable heat demand reductions can be made through cheaper measures, then it is hoped that ASHPs will still be affordable for many residents on Alderney. In Table 13, Table 14 and Table 15, packages of measure which have been deemed affordable were produced, with many of these same measures being found in Ref [12].

Table 13 – House Type 1, Affordable insulation Costs

House Type 1 – Affordable Insulation Costs	
Labour (£/Day)	175
Loft Insulation (£)	425
Floor Insulation (£)	742
Draft Proofing (£)	120
Number of Labour Days	2
CAPEX + Insulation (£)	1,637

Table 14 – House Type 2, Affordable insulation Costs

House Type 2 – Affordable Insulation Costs	
Labour (£/Day)	175
Loft Insulation (£)	300
Cavity Wall Insulation (£)	332
Solid Floor Insulation (£)	742
Draft Proofing (£)	120
Number of Labour Days	3
CAPEX + Insulation (£)	2,019

Table 15 – House Type 3, Affordable insulation Costs

House Type 3 – Affordable Insulation Costs	
Labour (£/Day)	175
Loft Insulation (£)	319
Floor Insulation (£)	742
Draft Proofing (£)	120
Number of Labour Days	2
CAPEX + Insulation (£)	1,531

As mentioned previously, for each house type it is assumed that each insulation measure will take a full day's labour, hence there being two days labour for measures at house types 1 and 3, and three days labour for measures at house type 2. For house type 1, loft insulation was not suggested in Ref [12], but for a detached home, the cost of fitting loft insulation is estimated at £600 for purchase and installation [23], thus the cost of materials came to an estimated £425. For draft proofing, purchases within this measure included thermal curtains and blinds, carpet underlays, letterbox brushes, and draught excluders, with these measures totalling approximately £120 [24].

How representative are the house types assumed?

According to the Energy Saving Trust publication in Ref [12], 31% of homes on Alderney are detached, 24% are bungalows and 18% are terraces (73% of houses on Alderney). Although many of these homes will have differing numbers of bedrooms and varying floor area, insulation quality and number of occupants living in each respective dwelling, it is important to find out how representative house types 1-3 are of housing on Alderney as a whole in terms of heat demand and kerosene consumption. With Alderney consuming around 2 million litres of kerosene per annum for both domestic and commercial purposes, it was estimated how much kerosene would be consumed if all detached homes, bungalows, and terraces had a heat demand profile similar to house types 1-3. Below in Table 16, the annual kerosene consumption of house types 1-3 is shown.

Table 16 – House Types 1-3, Annual Kerosene Consumption in Litres

Kerosene Consumption – House Type 1 (L/Annum)	3,678.55
Kerosene Consumption – House Type 2 (L/Annum)	1,665.60
Kerosene Consumption – House Type 3 (L/Annum)	2,432.95

Through information established from the Alderney Electronic census report 2021, there is an estimated 1494 homes on Alderney [25]. By using this information and applying the kerosene consumption values shown in Table 16, the total kerosene consumption of all detached homes, bungalows, and terraces can be estimated as shown in the Equations 5, 6 & 7 below.

Equation 5

$$Total\ Kerosense\ Consumption\ (Detached) = 1494\ x\ 3678.55\ x\ 0.31 = 1{,}703{,}684\ Litres/Annum$$

Equation 6

$$Total\ Kerosene\ Consumption\ (Bungalow) = 1494\ x\ 1665.6\ x\ 0.24 = \ 597{,}219\ Litres/Annum$$

Equation 7

$$Total\ Kerosene\ Consumption\ (Terrace) = 1494\ x\ 2432.95\ x\ 0.18 = \ 654{,}268\ Litres/Annum$$

By adding the annual kerosene consumption of all detached, bungalow and terraced houses on Alderney, domestic kerosene consumption came to slightly over 2.95 million litres per annum which is almost 50% higher than Alderney's current kerosene consumption for all purposes. From this it can be acknowledged that house types 1-3 are particularly poorly insulated properties, thus many properties will be of a higher insulation standard and should have payback periods that make ASHPs an economically feasible option in many instances. However, in the case that many homeowners are willing and able to install ASHPs on their property, consideration must be given to Alderney's grid constraints and the potential issues of network instability brought about by the inflexibility of electrified heating loads.

3.1.4 Conclusions & recommendations

Electrical system

From the electricity system analysis, we conclude the following:

A relatively small amount of renewable capacity (<1MW) could have a significant impact on energy cost on the island, potentially reducing diesel usage by 10-40%.

- This could be installed at a cost below £1M, potentially closer to £500k if Alderney were to shop around and obtain different quotes.
- Our analysis indicates wind as a more promising technology. Below 1MW installed, the relatively low efficiencies of commercial solar (<15%) would only provide a low amount of energy, with marginal benefit in the absence of a battery.
- Regarding batteries, we think that it would be good to demonstrate this once some renewable capacity has been deployed on the grid. For a small amount of renewable capacity (<500kW), we believe that the energy generating technology could be installed and controlled relatively easily by AEL and would not require battery support, as its rated power would typically be far below electricity demand.
- AEL currently have eight 500KW generators which are cycled periodically to cover warranty and allow maintenance to be performed. Renewable capacity could reduce the burden on the diesel generators.
- We believe that refurbished wind turbines offer more benefits than new. These are typically older, but well understood and established models, compared to some new small-scale products on the market which have seen limited deployment and could be less reliable. They could also be bought at a better price per kW installed.
- We think that there is a lot of merit in DistGen's PPA community owned arrangement, which has allowed them to install a number of turbines across the UK. We think that this could be an interesting opportunity for SoA to explore, as DistGen would pay for the CAPEX and SoA would only need to pay a PPA for energy generated by the turbines. This would also incentive DistGen to maintain the turbines and minimise downtime. Moreover, SoA could offer such a PPA via a competitive tender, which could lead to a lower price still.
- The diesel savings from a larger refurbished turbine could lead to cost savings of £400k per annum, which could be used to fund the PPA, be saved/invested for other uses or be used to reduce household energy bills.
- While our analysis indicates large diesel and cost savings, more research is needed: especially into the expected performance of the renewables which has a large impact on the diesel that is offset. We recommend that SoA carry out a full feasibility study, working with onshore project developers to properly estimate performance. The first step could be to install met masts at a few locations across the island to determine where the local wind resource appears best.

Heating system

To conclude the heating system analysis undertaken, a range of recommendations have been put forward that will play a role in reducing kerosene consumption for domestic heating purposes. For most of this heating system analysis the focus has been on the three example house types extracted from the EST's publication Supporting the Development of the States of Alderney Island Energy Policy. While these house types were particularly inefficient in terms of their insulation quality and kerosene consumption, they were effective in allowing the analysis to highlight the range of factors that need to be considered when replacing a home's heating system and current means of insulation. The house types that were used also demonstrated how one low-carbon heating solution may be more appropriate for one house type over another, depending on how fuel usage is distributed. This was seen when assessing the economic feasibility of ST, where house type 2 was the only property that would see payback achieved over the typical ST system lifetime of 20 years due to a smaller, less expensive installation being required to cover a disproportionality high hot water demand compared to the other two house types used in this analysis.

Reflecting on the methodology and assumptions used to calculate ST purchase and installation costs, it is highly likely that the costs calculated for each house type would vary more in reality due to the differing sizes of hot water cylinders required. For example, house type 2 would likely require a larger water cylinder than the other two house types to provide adequate hot water storage. This would subsequently affect the overall cost and payback period of the system. While ST was economically unfeasible for two out of the three of homes assessed, efforts should still be made on Alderney to identify any properties which will benefit financially from ST in the long-term. If ST is indeed economically feasible for numerous properties on the island, efforts should be made to purchase and install ST systems in bulk to minimise the costs associated with transport of components and skilled labour to Alderney. This could be done through the establishment of a procurement body within the SoA.

When focusing on the installation of ASHPs on Alderney, it is clear that poorly insulated homes must prioritise improvements to insulation quality prior to considering renewable heat generation options. Improvements to insulation can come through a wide range of measures, with several being far more affordable than others. In the case that measures such as solid wall insulation are required to considerably reduce the overall space heating demand of certain properties, it is recommended to go ahead with this measure alone as the expectation is a very limited number of households on Alderney would be able to afford both solid wall insulation and a new ASHP system. When considering cheaper insulation measures such as loft insulation, cavity wall insulation, underfloor insulation, and draught proofing, the SoA should prioritise these measures for both public and private housing which currently lack these forms of insulation. To have these measures put in place within the short-term scenario, the SoA could provide some financial assistance towards these insulation procedures, especially for households which lack the income to pay for such home improvements themselves. Even with the majority of homes on Alderney continuing to consume kerosene beyond the short-term scenario, heat demand and kerosene consumption will lower over time as the energy efficiency of the island's housing stock is improved. Again, the use of a body within the SoA to strategically source the required bulk materials and labour will play some part in reducing costs.

During the heating system analysis, it was found that the three house types modelled were not representative of the wider housing stock on Alderney. It was found that if these houses were representative of the island's housing stock, then domestic kerosene consumption on Alderney would be almost 50% higher than the island's current kerosene consumption for all purposes. While this realisation is positive in the sense that ASHPs could be economically feasible for a greater number of homes on Alderney, issues concerning grid stability will come into play if too many homes switch to an electric source of heating without due diligence. This is because of the inflexibility of electrified heating loads which are highly seasonal and are most present are certain times of day (mornings and evenings). It is important that AEL monitor the uptake of ASHPs closely to ensure these heating loads can be satisfied without Alderney's distribution network being compromised.

To summarise the findings and recommendations from this heating system analysis:

- The installation of ST should only be considered in properties where hot water demand takes up a significant proportion of overall heat demand if payback is to be achieved.
- Improvements to the insulation of all homes on Alderney should be considered regardless of the economic feasibility of ST or ASHP. Fuel savings and subsequent cost savings will be made regardless.
- The SoA should support residents to improve their insulation, especially for those on lower income, perhaps through means tested subsidies. This would also play a role in alleviating fuel poverty on the island.
- For homes that are already suitably insulated or can afford both new insulation and a new ASHP system, ASHPs should be considered as payback will likely be achieved in many instances. However, AEL should closely monitor the impacts that increased electrification will have on the stability of Alderney's grid, especially the impact inflexible heating loads.
- For all technologies and measures suggested in this analysis, a central procurement body should be established which is responsible for the bulk ordering of improved heating solutions to drive down transport and labour costs to Alderney.

3.2 Medium term scenario (10-20 years)

3.2.1 Overview

The medium-term scenario is a continuation of, and therefore builds upon, the proposed favoured short-term system electricity and heat scenarios proposed in Section 3.1. Further assessment is made seeking to maximise on island renewable energy generation capability to meet on island demand and where possible remove continued reliance on fossil fuel. As we increase the level of variable renewable energy generation onto the system, energy storage capability becomes an important system component for grid stability.

With grid limitations preventing short- and medium-term heating system electrification we consider what level of heating electrification may occur by modelling varying low levels of ASHP uptake on Alderney. The varying levels of increased load expected on the Grid because of Renewable Heat uptake is examined.

3.2.1 Electrical system

Table 17 shows the key results of the electricity system simulation, while Table 18 shows the difference between these results and the current Alderney energy system scenario (S.1).

Table 17 – Key results of the mid-term scenarios: with baseline battery cost (M.1) and 50% cheaper batteries (M.2). Scenarios S.3 (preferred short-term scenario) and S.1 (current system) are shown as a comparison (in grey).

Scenario name	Energy technologies				Key results					
	D	W	S	B	CAPEX	OPEX	Diesel consumed	Net present cost	LCOE	Renewable fraction
	MW	MW	MW	MWh	£m	£k/yr	L (M)/yr	£m	£/MWh	%
M.1. Lowest cost – baseline battery	0.5	1.7	1.5	0.85	3.3	94	0.39	6.8	84	78%
M.2. Lowest cost – "cheap" battery	0.5	1.7	1.5	1.7	3.3	91	0.32	6.4	80	82%
S.3. Early refurbished wind (short term)	2	0.85	0	0	1.1	138	1.13	9.9	128	40%
S.1. Current	2	0	0	0	0	118	1.83	13.2	171	0%

Table 18 – The two mid-term scenarios compared to the current system (Scenario S.1).

Scenario name	CAPEX	OPEX	Diesel consumed	Net present cost	LCOE
	£m	%	%	%	%
M.1. Lowest cost – baseline battery	+3.3	-21%	-79%	-48%	-51%
M.2. Lowest cost – "cheap" battery	+3.3	-23%	-82%	-51%	-53%

Both mid-term scenarios show significant further LCOE reduction compared to the current system: with about 50% reduction in LCOE and 80% reduction in fuel usage. The LCOE reduction is visualised in Figure 16. The CAPEX would be about £3.3M, which could be at least partially funded by the diesel saved for the short-term scenario over the early years.

Our results also imply that one 500 kW diesel generator would be sufficient, providing something of a baseload. This would mainly operate during the night-time, with the solar combined with wind turbine capable of supplying much of the daytime load.

The amount of renewable capacity installed is 3.2 MW (3.7 MW including the diesel generator) in both cases, split almost equally between onshore wind and solar. This is lower than the 5 MW that the HV system has been quoted as being able to handle (see Section 1.3) and so we believe should be suitable to install without requiring large investment in grid infrastructure.

The cost of the batteries was found to only have a marginal effect on the simulation. For scenario M.2, with battery cost reduced by 50%, the optimal system configuration was to double the quantity of the batteries, while keeping the other renewable technologies the same. The result was a decrease in fuel usage of almost 20% and slight LCOE reduction of 5%. This shows that battery cost is not a significant driver for the future system.

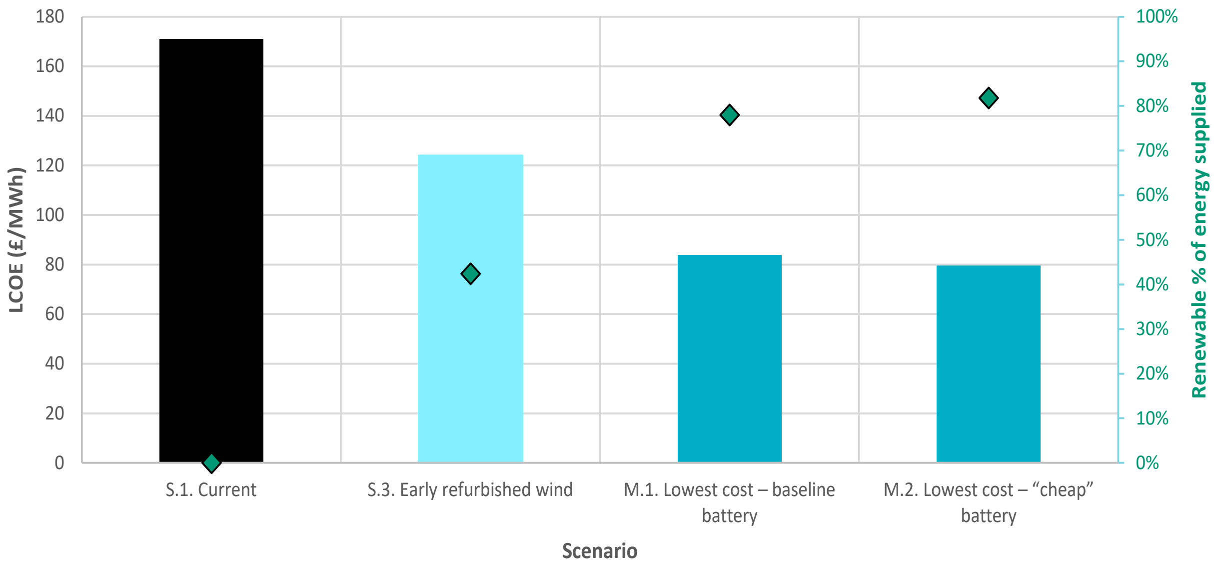

Figure 16 – The two mid-term scenarios compared to the current Alderney energy system (scenario S.1) and the preferred short-term scenario (S.3)

Sensitivity to diesel price

Because diesel prices fluctuate and are difficult to predict with accuracy, we modelled a sensitivity to demonstrate how the optimal system configuration is affected. Table 19 shows the key parameters for the high and low diesel price scenarios, as well as the baseline fuel price of £0.56/l.

Table 19 – Key parameters for the diesel price sensitivity

Scenario name	Energy technologies				Key results					
	D	W	S	B	CAPEX	OPEX	Diesel consumed	Net present cost	LCOE	Renewable fraction
	MW	MW	MW	MWh	£m	£k/yr	L (M)/yr	£m	£/MWh	%
M.1. Lowest cost – baseline fuel cost **£0.56/l**	0.5	1.7	1.5	0.85	3.3	94	0.39	6.8	84	78%
M.3.1 Lowest cost – low fuel cost **£0.45/l**	0.5	1.7	1	0.85	3.1	96	0.42	6.3	77	76%
M.3.2 Lowest cost – high fuel cost **£0.67/l**	0.5	1.7	2	0.85	3.5	92	0.37	7.4	90	79%

In all three cases the system chooses two wind turbines and a single diesel generator. There are, however, marked differences in the solar capacity: with the high fuel price scenario preferring a lower amount of solar and the high fuel price a higher amount of solar. As the fuel price increases, additional solar becomes cheaper and displaces diesel generation on the system.

In all three cases the LCOE is significantly lower than the diesel-only equivalent system. In the high fuel cost scenario the LCOE of the renewable energy system is 55% lower than the diesel equivalent, this gap narrowing to 45% for the cheap diesel scenario.

These results imply that the renewable system is good value for money, even in the case that diesel prices fall significantly.

3.2.2 Heating system

In the short-term scenario the feasibility of ASHPs were assessed using three example house types extracted from Ref [12] as part of a wider heating system analysis. Later in this analysis it was found that these example house types were of a particularly poor insulation standard and were not reflective of the wider housing stock on Alderney when their kerosene consumption was measured against the current kerosene consumption on the island for both domestic and commercial purposes. While this is good in the sense that more properties on Alderney will have insulation that is sufficient in making ASHPs an economically feasible heating option, it remains unclear what additional electrical demand would need to be satisfied if a portion of Alderney's housing stock switched to ASHPs as their means of meeting space heating and hot water demand. This section gives some indication of what the additional electrical demand brought about by ASHPs may look like based on assumptions used in the short-term scenario. These assumptions will be used alongside estimates of what a typical Alderney household's heat demand may look like by using typical heat demand values of homes on the UK mainland.

For this analysis, the assumptions used were extracted from the short-term scenario and are listed below:

- Each ASHP installation in discussion has a seasonal performance factor (SPF) of 3.2.
- Each ASHP installation in discussion operates for 1,456 hour per annum.

When re-evaluating what a better insulated Alderney home's heat demand may be, medium and high gas consumption values for typical UK homes were used which would meet the annual heat demand of mainland properties connected to the gas grid [26]. Medium demand is estimated at 12,000 kWh/Annum, while high demand is estimated at 17,000 kWh/Annum. Using these values alongside the two short-term assumptions listed above, the additional annual electrical demand can be calculated for what can defined in this analysis as a typical Alderney home. The results are shown below in Figure 17.

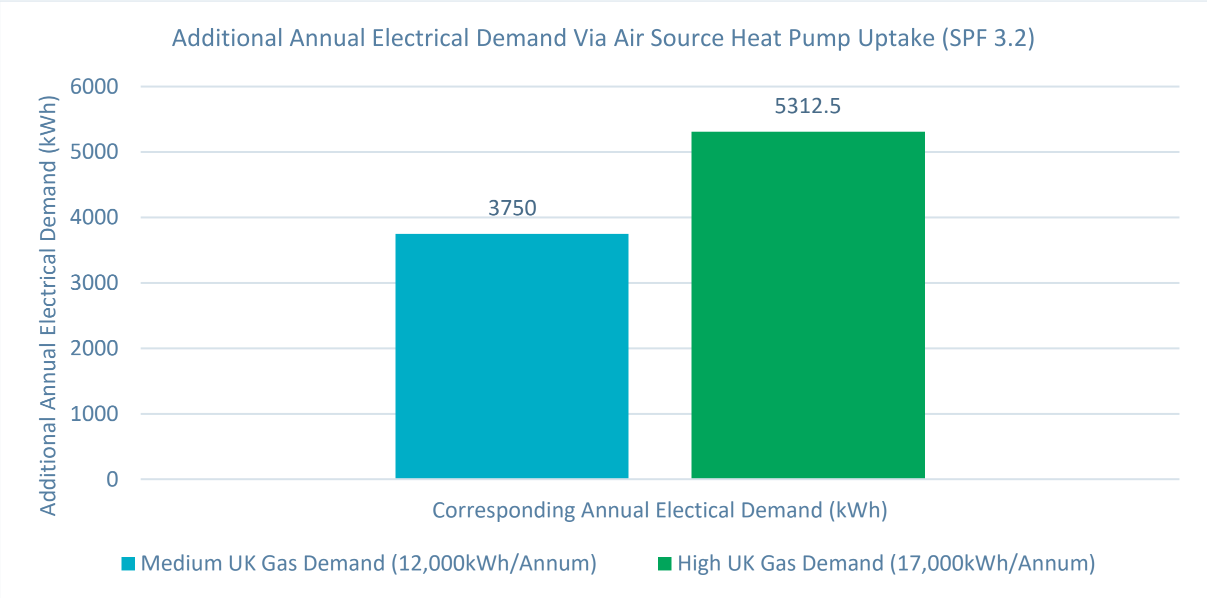

Figure 17 – Additional Annual Electrical Demand via Air Source Heat Pump Uptake Using Medium and High UK Gas Demand Values

With the additional annual energy requirements now known, the average power demand of a typical Alderney home using ASHPs can be calculated by dividing the additional annual energy demand by 1,456 (ASHP hours of operation). The results are shown below in Figure 18.

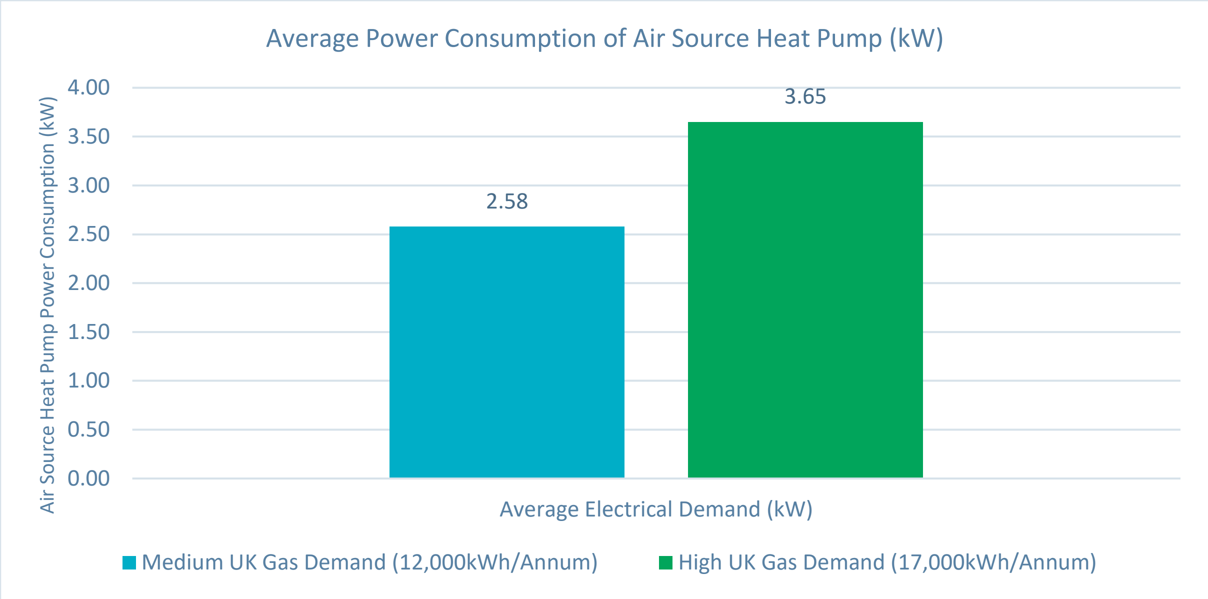

Figure 18 – Average Power Consumption of Air Source Heat Pumps on Alderney Using Medium and High UK Gas Demand Values

Using the results from Figure 17 and Figure 18, the implications of different levels of heating system electrification on Alderney can be assessed. With the average power consumption in the high gas demand setting only coming to 3.65 kW, a 5 kW ASHP has been deemed sufficient for the typical Alderney home under both gas demand settings. This then allows the island's peak additional electrical demand to be calculated under different levels of ASHP uptake. This is done by multiplying the average and peak demands by 1,494 (the number of homes on Alderney) and the fraction of ASHP uptake experienced under each setting in discussion, as shown in Figure 19.

Equation 8

$$Total\ Additional\ Electrical\ Demand\ (kW) = ASHP\ Electrical\ Demand\ (kW)\ x\ 1{,}494\ x\ ASHP\ Uptake\ (\%)$$

Below in Figure 19, the average and peak electrical demand seen during 5%, 10% and 15% ASHP uptake are shown for both medium and high gas demand settings.

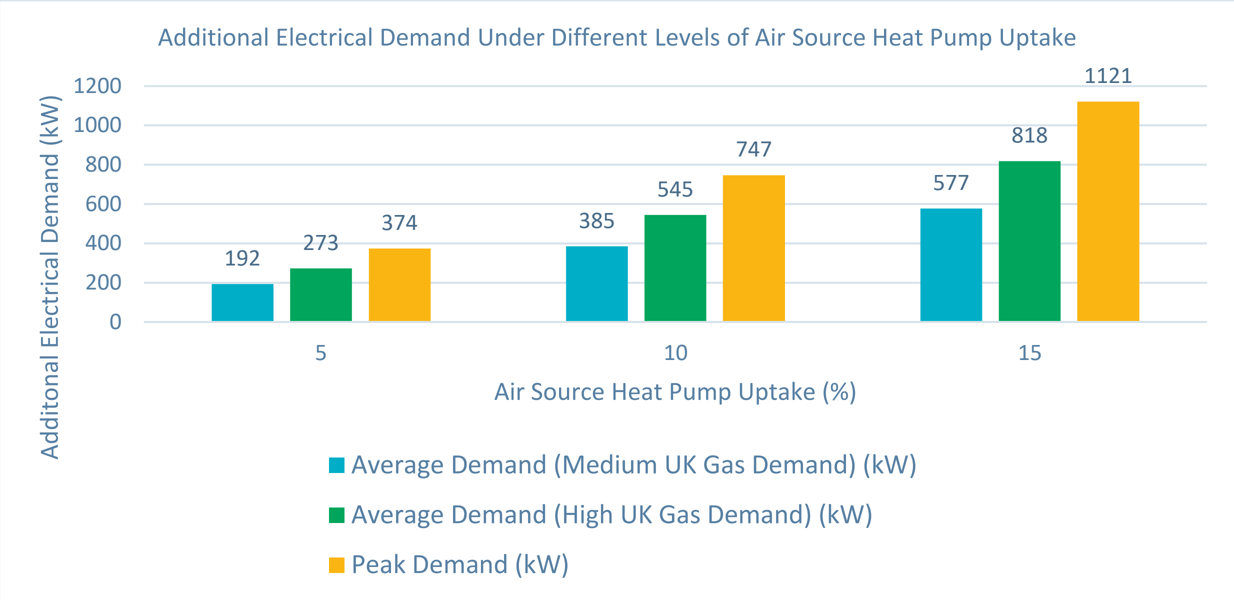

Figure 19 – Additional Electrical Demand Under Different Levels of Air Source Heat Pump Uptake

From the results in Figure 19, even a 5% ASHP uptake brings about significant additions to electrical demand on the island. For context, the total electricity demand on Alderney at present typically varies between 300 kW and 700 kW, meaning Alderney's grid would need to be capable of delivering typical peak demands around 50% higher than is currently required. Annual peak demand on Alderney reaches around 1.3 MW in the summer months when ASHPs are unlikely to be operational. This indicates a 5% uptake in ASHPs could be managed at present to meet domestic space heating demand during the winter months. However, uptake beyond 5% could bring additional electrical demands which may cause grid stability issues due to the inflexibility of electrified heating loads. SoA and AEL must have a clear strategy in place when attempting to electrify a portion of its domestic heating demand so that an optimal balance can be struck between decarbonisation and continuous grid stability between now and the beginning of the medium scenario.

3.2.3 Interconnectors

A priority goal of the SoA Energy Team was to unlock the revenue potential from leasing seabed rights surrounding the island. Of significant potential is tidal stream energy, with up to 3 GW of potential resource identified in the Alderney Race alone [27]. French authorities have already permitted two tidal stream projects both now being supported by Interreg's Tidal Stream Industry Energiser project (TIGER) where developers are seeking to vary consents for a 12 MW and 17.5 MW projects on the French side of the Alderney Race (Raz Blanchard). For these sites to succeed they require significant revenue support in the form of a FiT where an agreed inflated market price for the electricity exported to the French Grid is paid over a fixed duration. This is funded by State Governments.

This presents Alderney with two significant barriers for developing their territorial waters:

- Route to Market: Alderneys energy demand peaks at 1.3 MW far below the likely capacity of any marine renewable project seeking to reach a competitive LCOE within Alderney waters. Alderney would require access to an export market via either an electrical interconnector (likely to France) at significant cost or perhaps through production and sale of Hydrogen (market yet to establish).

- Feed in Tariff: Tidal stream is still a relatively nascent developing technology with a high LCOE (estimated at between £250-£300/MWh). Predictions for future global tidal stream deployment are 2.3 GW installed by 2030 with LCOE falling to c.£85/MWh [28]. It is likely that such projects will still require capital grant funding at this stage. Such feed in tariffs and capital grant funding are considered unaffordable for the medium-term scenario.

As such we consider development of marine renewable energy projects within Alderney waters unlikely in the short- and medium-term timeframes. In the following section we have investigated potential interconnector options for Alderney and establish and estimate the level of CAPEX investment required to establish an interconnector and access to export markets which could unlock revenue generation from Alderney waters.

Alderney interconnector options

Interconnectors are a way of connecting electrical systems of neighbouring jurisdictions. For Alderney, an electrical interconnector could be a way to both import and export electrical power to and from the Island. Due to Alderney's limited electrical demand on the island and the surrounding surplus of renewable resources and the points raised above, an interconnector would be required to enable exploitation of local marine renewable resources over and above the islands demand requirements.

Existing and proposed interconnector projects have been reviewed to understand the cost implications required for an Alderney interconnector. There are many factors that influence an interconnector development, for example, access, converter stations, HVDC subsea cables, routes implemented, EIAs, vessels, matching different supplies on either end, cost per kilometre, and capacity, (all having various limitations). To keep this report concise, see Appendix 1 for detail on the calculations of cost estimates for the following Alderney interconnectors scenarios.

HVDC interconnector (bi-polar)

Assumptions are based on a HVDC cable voltage of ±350 kV, and a capacity of 800 MW to define total costs (including the respective converter station infrastructures). The cost for a HVDC bi-polar (enabling both Import and export of electricity) interconnector between Alderney and France (18 km), is estimated to be c.€352m. Between Alderney and Guernsey (37 km), CAPEX cost is estimated to be c.€384m. Such high costs are deemed significant and without revenue streams from marine renewable projects developing in Alderney waters in the medium term, make the financing of such interconnectors unlikely. As such we investigated the potential of a transmission line as a way of connecting the Island to a neighbouring grid.

HVAC transmission cable (mono-polar)

CAPEX estimates for a HVAC transmission line connector to France capable of either importing or exporting electricity with the island is estimated at c.£25m and could enable the import or export of up to 220 MW. The same transmission line to Guernsey is estimated to cost c.£51m. Whilst this option is more affordable a business case would need to be established by SoA which weighs up potential revenue from developing up to 220 MW of marine energy (with an appropriate FiT) vs the cost of financing the transmission cable.

3.2.4 Conclusions & recommendations

Electrical system

From our extended energy system analysis, we would recommend the following for the medium-term case:

- Once experience has been gained installing and operating small scale renewable systems in the short-term scenario (<1 MW), the next stage, we believe, would be to scale up the renewable energy system to 3-4 MW, depending on the technologies preferred.
- Combined with energy storage, this could mean that only a single diesel generator would be required for daily use, with 1-2 further generators for backup.
- Our analysis indicated that a roughly 50:50 split of wind and solar capacity was the optimal choice, which would reduce diesel usage by 80% compared to the current “diesel only” case. These renewables work in tandem, limiting the fluctuations in the renewable sources and limiting the need for curtailment.
- For this amount of renewable energy, we believe that battery storage would be required, to smooth out power and voltage fluctuations and enable excess renewable capacity to be stored.
- The cost of this storage only had a marginal impact on LCOE. Battery prices into the future are very uncertain, as the use cases are still emerging, and so we think it would be worth revisiting as the requirement becomes apparent.
- Even in the case of lower diesel prices the renewable system stands up well, and so this represents a good investment which will improve Alderney’s energy security as well as lowering LCOE.
- At this stage, we believe that onshore renewable energy makes the most sense from a cost perspective: the technology is mature and market ready. We don’t expect this to be the case for tidal stream until well into the 2030s, and there is likewise not an economic case for an interconnector.
- The impact of electrification in the heating system could have an impact on the electricity demand and apply constraint to the grid. This has not been examined directly, and we believe that it should be re-evaluated once Alderney have formulated a desired heating system approach.
- While we don’t believe land use will be a big issue for the island, we believe that Alderney would benefit from re-examining their land use plan once approximate capacities of renewables have been planned out. This will allow the renewable energy technologies to be optimally deployed to avoid local opposition and negative visual impact.

Heating system

Calculating the increase in electrical demand expected for varying levels of ASHP uptake (heating system electrification) has confirmed that Alderney’s grid would quickly become overloaded with as little as 5% household uptake.

- Typical demand increase per household will vary on a case-by-case situation but is expected to be between 3750 kWh - 5312 kWh per year assuming households have been sufficiently insulated.
- Based on average household heat demand even a 5% uptake of ASHP could increase typical peak demand by over 50%, adding 374 kW. A 15% ASHP uptake would lead to a demand increase of between 577 kW - 1,121 kW.
- Based on these findings it is strongly recommended that SoA or AEL ensure there is sufficient control and monitoring of domestic renewable heat installations on the island.
- Any plan to electrify any part of Alderney's energy system will need to be managed carefully.

Interconnector options

- The CAPEX requirements for Alderney to develop its own HVDC Bi-Polar interconnector to France (c.€352m) or Guernsey (c.€384m) are prohibitive and considered financially unfeasible in the medium term.
- Whilst CAPEX requirements for a mono pole transmission link to France (c.£25m) and Guernsey (c.£51m) are significantly less than an interconnector, it remains likely unfeasible to finance without debt, even with revenue generation from 220MW marine energy project development. A feasibility study is recommended to establish whether this option may be worthwhile for Alderney, however it does not unlock the significant revenue potential in Alderney waters in the long term.

3.3 Long term scenario (20+ years)

3.3.1 Overview

Our modelling for the short and medium term has shown that Alderney has the potential to become more independent regarding electricity production on the island. Weening the islands heating system off Kerosene is particularly challenging compounded by a grid currently unable to accept significant additional load and in need of significant upgrades should it need to do so.

Whilst the proposed short and medium scenarios achieve to some extent the strategic objectives of maintaining or reducing energy bills, improving security of supply and de-carbonising the energy system, a solution which enables the island to develop and utilize the significant renewable resources found within Alderney's territorial waters and generate revenue through seabed licencing has proven difficult. Whilst there remains the possibility of access to export markets via an interconnector, stand alone, self-funded interconnectors appear unlikely feasible for Alderney. As such this long-term scenario shifts attention to the nascent technology of Hydrogen production and storage.

Alderney lies next to the world's busiest shipping lane in the world, with the transport industry and shipping, with the potential to shift to Hydrogen based propulsion over the next 30 years. With Braye harbour positioned to the north of the island facing the English Channel, this section of the report will investigate the current and future predicted status of the Hydrogen market and how Alderney may be well positioned to capitalise on it.

3.3.2 Hydrogen production and storage

Introduction and overview to 2050 projections

Hydrogen energy has spurred significant waves of interest with very little industry impact to date, however two factors may now change this. Firstly, worldwide governments after COP 26 have rallied behind the net zero emission targets by 2050, limiting global temperature rise to 1.5°C laid out by the Paris Agreement [30] [31]. This allows hydrogen to emerge as a key option for reducing emissions of the industrial heavy energy users. Secondly, falling costs of renewable energy and electrolysers are improving the economic feasibility of "green" hydrogen. As more variable renewables are introduced into the mix, for example, wind and solar photovoltaic (PV), they also create increased demand for energy generation flexibility and storage. Therefore, green hydrogen can help to deliver and extend the growth of renewable electricity generation. Hydrogen and hydrogen-based fuels according to the International Renewable Energy Agency (IRENA), [32], are projected to fulfil a sizeable share of final energy demand in 2050 (Figure 20). The dominant production pathway being green hydrogen, complemented by "blue" hydrogen, based on fossil fuels with the added carbon capture and storage (CCS) and resulting in the current "grey" hydrogen production, that is based entirely on fossil fuels to be completely phased out. For these reasons, and to align with industry projects Alderney should focus on its future options to produce green hydrogen which would further support the case for Alderney to exploit the renewable energy resources within its territorial waters (potential secondary revenue stream).

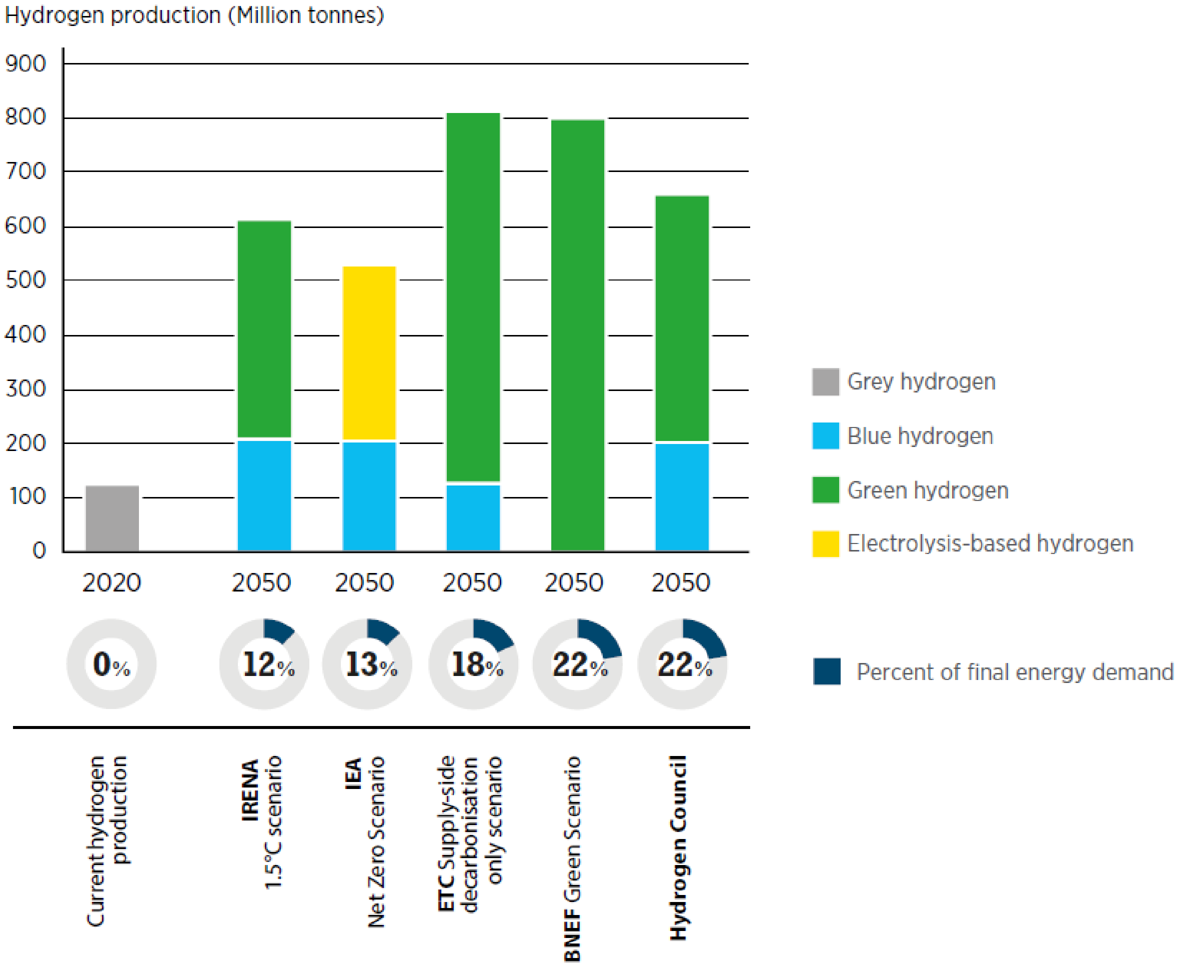

Figure 20 – Graphical representation of the estimates for global hydrogen demand in 2050 in million tonnes, from IRENA, International Energy Agency (IEA), Energy Transition Commission (ETC); Bloomberg New Energy Finance (BNEF) and Hydrogen Council. [32] [38] [39] [40].

Hydrogen production costs are a fundamental part of energy market analysis, as these costs are important when designing policy and analysing projections [33]. As the hydrogen sector is fast-moving it must be noted that various gaps in knowledge and understanding should be acknowledged. Within this section the costs of construction and operation are addressed, that reflect the cost of building and operating a generic production plant for electrolysis technology. A comparison of costs are presented as levelised costs, i.e., a measurement of the average cost per MWh of hydrogen produced over the full lifetime of a plant. As levelized costs provide a straightforward pathway of consistently comparing the costs of different production technologies, using estimates from real values in 2020. The focus will be on costs simplified and incurred by the producer throughout the lifetime of the hydrogen plant [33]. With hydrogen there is an inherent uncertainty when estimating current and future costs of hydrogen production, especially because hydrogen technologies are only phasing through demonstration. These uncertainties are also focused on fluctuating electricity and fossil fuel prices.

UK Government 2030 hydrogen targets

As we head towards 2030, and according to the UK Government's Hydrogen Strategy the UK will measure hydrogen market development success across a range of strategic outcomes: [34]

- "Progress towards 2030 ambition: 5GW of low carbon hydrogen production capacity with potential for rapid expansion post-2030; hope to see 1GW production capacity by 2025.
- Decarbonisation of existing UK hydrogen supply: Existing hydrogen supply decarbonised through CCUS and/or supplemented by electrolytic hydrogen injection.
- Lower cost of hydrogen production: A decrease in the cost of low carbon hydrogen production driven by learning from early projects, more mature markets and technology innovation.
- End-to-end hydrogen system with a diverse range of users: End user demand in place across a range of sectors and locations across the UK, with significantly more end users able and willing to switch.
- Increased public awareness: Public and consumers are aware of and accept use of hydrogen across the energy system.
- Promote UK economic growth and opportunities, including jobs: Established UK capabilities and supply chain that translates into economic benefits, including through exports. UK is an international leader and attractive place for inward investment.
- Emissions reduction under Carbon Budgets 4 and 5: Hydrogen makes a material contribution to the UK's emissions reduction targets, including through setting us on a pathway to achieving Carbon Budget 6.
- Preparation for ramp up beyond 2030 – on a pathway to net zero: Requisite hydrogen infrastructure and technologies are in place with potential for expansion. Well established regulatory and market framework in place.
- Evidence-based policy development: Modelling of hydrogen in the energy system and input assumptions improved based on wider literature, qualitative and quantitative evidence and real-world learning. Delivery evidence from innovation and deployment projects collected and used to improve policy making."

Hydrogen applications, barriers, and priority settings

To ensure that the technologies and solutions selected are most efficiently deployed, careful management of decarbonisation strategies will be required. Figure 21 below compares possible end users which are based on their application size and hydrogen solution maturity in comparison to electricity-based applications. Making a shift to a sustainable economy is not merely about switching energy sources by keeping the current energy system, however, it's to improve the system to be more efficient, justifiable, and equitable through the energy that is developed. Doing so involves

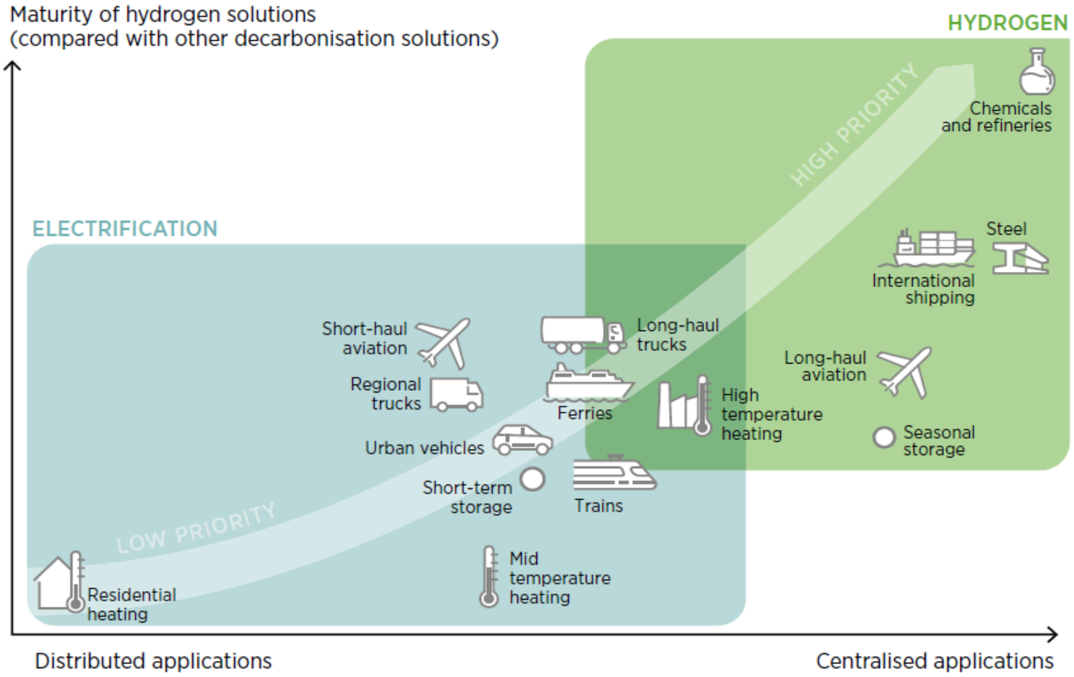

Figure 21 – Clean hydrogen policy priorities from electrification to hydrogen applications [32] [41].

reducing unnecessary energy consumption across many final uses and changing the current economic system [35]. Of note for Alderney is the priority of international shipping identified. Alderney being situated next to the world's busiest shipping channel is of significance (see Figure 22).

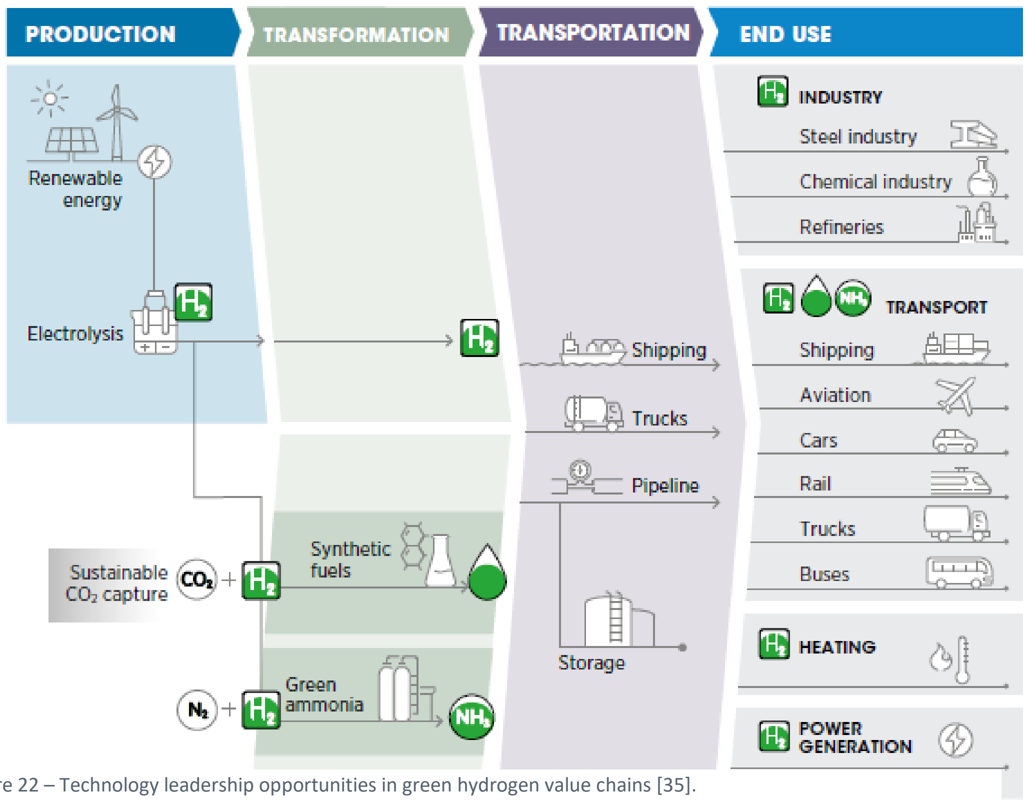

Figure 22 – Technology leadership opportunities in green hydrogen value chains [35].

The following barriers currently prevent clean hydrogen from making a larger contribution to the energy transformation and are the reason for hydrogen only being considered for Alderney in the long-term scenario. [35];

1. With green hydrogen the cost is still very high relative to high-carbon fuels. This not only includes the cost of production but also the costs of transporting, converting and storing hydrogen.

2. There is still a low technical readiness level (TRL) in the hydrogen value chain that will need to be proven at scale. For example, the maritime trade there is only one prototype vessel that can transport liquid hydrogen.

3. Significant energy losses are incurred through hydrogen production and conversion at each stage of the value chain (including the different stages from production, transport, conversion and end use).

4. Predictions have estimated that 21,000 TWh of energy will be consumed by electrolysers in the production of hydrogen by 2050.

5. Substantial investment, and supply chain demand remain high risk for wide-scale hydrogen production and necessary infrastructure that would reduce the overall cost. The difficulty with building out necessary hydrogen infrastructure, and without the required demand, any investment remains very risky to wide-scale production. This will be required to reduce costs of the technology, however in 2020 these economies are too costly.

This analysis offers insights into how countries and stakeholders can navigate the uncertainties and shape the development of hydrogen markets. The following are key findings when shaping the geopolitical pathway whist trying to reduce the risk of a hydrogen future [35]:

"Hydrogen is part of a much bigger energy transition picture, and its development and deployment strategies should not be considered in isolation. Setting the right priorities for hydrogen use will be essential for its rapid scale-up and long-term contribution to decarbonisation efforts. The 2020s could become the era of a big race for technology leadership, as costs are likely to fall sharply with learning and scaling-up of needed infrastructure. Equipment manufacturing offers an opportunity to capture value in the coming years and decades. Hydrogen trade and investment flows will spawn new patterns of interdependence and bring shifts in bilateral relations.

Countries with an abundance of low-cost renewable power could become producers of green hydrogen, with commensurate geo-economic and geopolitical consequences. Hydrogen could be an attractive avenue for fossil fuel exporters to help diversify their economies and develop new export industries. Supporting the advancement of renewable energy and green hydrogen in developing countries is critical for decarbonising the energy system and can contribute to global equity and stability. International co-operation will be necessary to devise a transparent hydrogen market with coherent standards and norms that contribute to climate change efforts meaningfully."

As such, it is critical that SoA continue to monitor the hydrogen industry development and where possible engage with relevant stakeholders. It is likely Alderney's significant and so far untapped renewable resources will be of significant interest to the Hydrogen production market.

Levelised cost of hydrogen

Hydrogen capacities, costs and production are expressed in various ways, as such to clarify in terms of energy units: capacity is denoted by MW and quantities denoted by MWh. When comparing different technologies worst case scenarios are expressed by using the higher heating value (HHV). The Levelised cost of hydrogen (LCOH) is the discounted lifetime cost of building and operating a production asset, this cost per energy unit of hydrogen produced is then expressed as (£/MWh). As expressed in Equation 9, the LCOH production is a ratio of the net present value (NPV) of the total costs to the (NPV) of the total amount of hydrogen production over the plant's lifetime [7] [33].

Equation 9

$$Levelised\ Cost\ of\ Hydrogen = \frac{NPV\ of\ Total\ Costs}{NPV\ of\ Hydrogen\ Production}$$

Types of electrolysis

Within this scoping document the production of hydrogen will only focus on electrolysis, eliminating Carbon Capture, Utilisation and Storage (CCUS) enabled methane reformation, (Steam Methane Reformer (SMR) and Autothermal Reformer (ATR) options); and secondly CCUS-enabled biomass gasification. It is assumed that should Alderney embark in hydrogen production they would do so using its surrounding renewable resources to do so (i.e. produce green hydrogen). Electrolysis is the process of using electricity produced from renewable energy to split water into hydrogen and oxygen. In the future there are plans to expand electrolysers, i.e. units or plants from the 10s to the 100s of MW scale in various sizes. However, with larger projects the plants are made up of a series of smaller modules or stacks, that are currently, in stack sizes of typically up to 5 MW in size. For simplicity this we have assumed a 30-year lifetime for electrolysis technologies, with a plant size of 10 MW (in 5 MW size scales, with exception to Solid Oxide Electrolysis) between a timescale of 2020-2050 [33].

Alkaline electrolysis

Alkaline electrolysis is the most mature form of electrolysis that occurs between two electrodes, namely the anode and cathode. This reaction separates the water into hydrogen and oxygen in a solution comprised of water and a liquid electrolyte. The electrical conversion efficiency in Alkaline electrolysis is circa 77% (in 2020) with an assumption to increase to circa 82% (by 2050) [33]. The drawback of Alkaline electrolysis compared to other technologies, such as Proton Exchange Membrane (PEM), is the response time to power supply fluctuation resulting in added cost to pair Alkaline electrolysis with renewable energy sources efficiently. It may be that Alderneys tidal stream resource (highly predictable) may still be suitable for this technology however further research is required.

Proton Exchange Membrane electrolysis

Proton Exchange Membrane (PEM) electrolysis splits water by using an ionically conductive solid polymer. The electrical conversion efficiency in PEM electrolysis is circa 72% (in 2020) with an assumption it will increase to circa 82% by (2050) [33]. The benefit of using the PEM is rapid dispatchability that has the ability to match renewable energy outputs, for example wind farms. Resulting in low carbon hydrogen production or the provision for grid response.

Solid Oxide Electrolysis

Solid Oxide Electrolysis (SOE) uses high-temperature electrolysis, circa 500 degrees centigrade, in comparison to technologies like Alkaline and PEM that are both low-temperature electrolysis. At present SOE is very limited commercially, however the future potential of this technology at large scale, once mature could be significant. The main advantage for SOE is its electrolysis efficiency at such high temperatures. The electrical conversion efficiency in SOE electrolysis is circa 74% (in 2020) with an assumption it will increase to circa 86% by (2050) [33]. To obtain the temperatures require for SOE, possible pairing has been considered with future nuclear power stations, where the benefit can come from both high-temperature heat and electricity from the same source.

Conclusion

Having a comparison of LCOH across different technology types it is suggested that Alderney may want to a focus on PEM technology. This is because PEM is expected to supersede alkaline electrolysis technology due to higher efficiencies and better response times for H2 production. PEM is anticipated to reach a lower LCOH for £/MWh of hydrogen. The LCOH of Alkaline and PEM are expected to see a reduction of over the period 2020-2050 (suitable for Alderney's long term energy

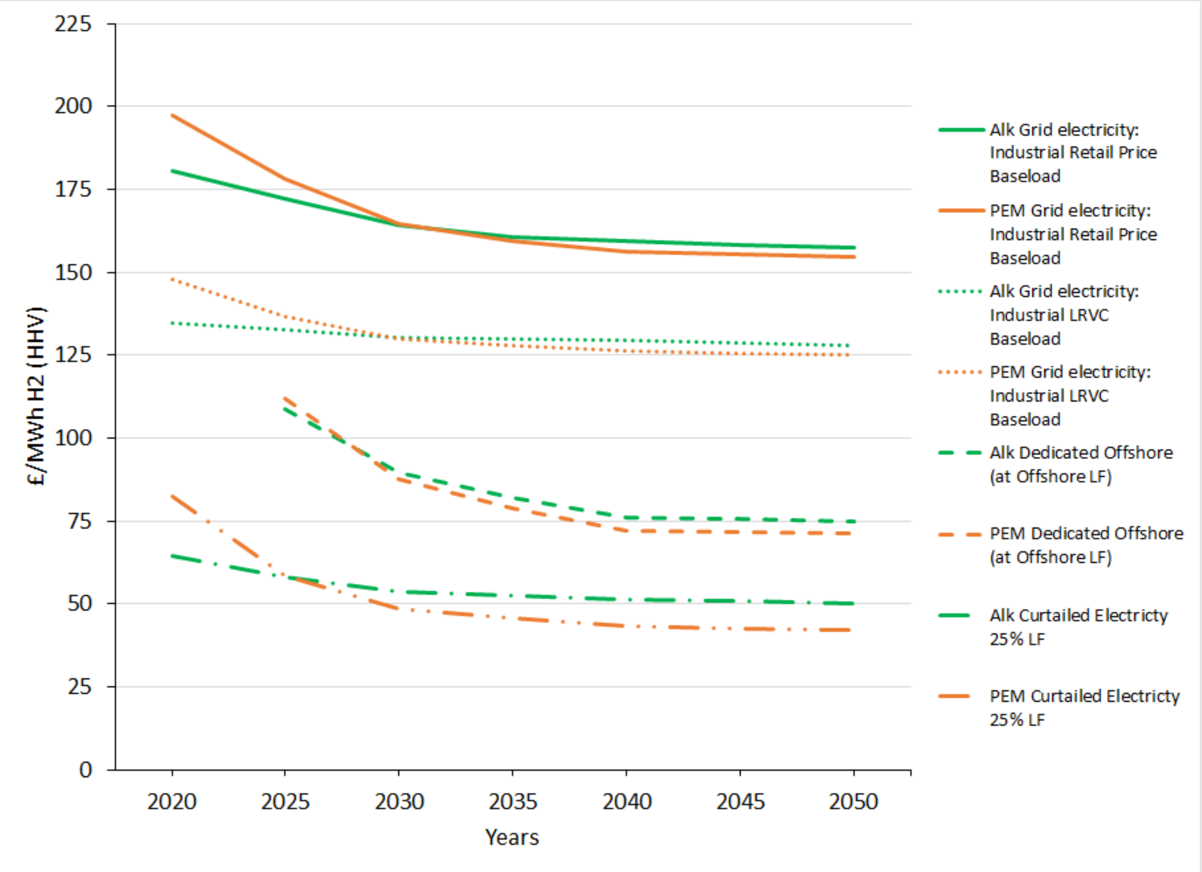

Figure 23 – Comparison of LCOH estimates across different technology types at central fuel prices commissioning from 2020 to 2050, £/MWh H2 (HHV) [33].

system scenario) (see Figure 23). From the same model further estimates are achieved for PEM electrolysis technology under the CAPEX for the same timescale, 2020-2050, for £/MWh of hydrogen (Figure 24).

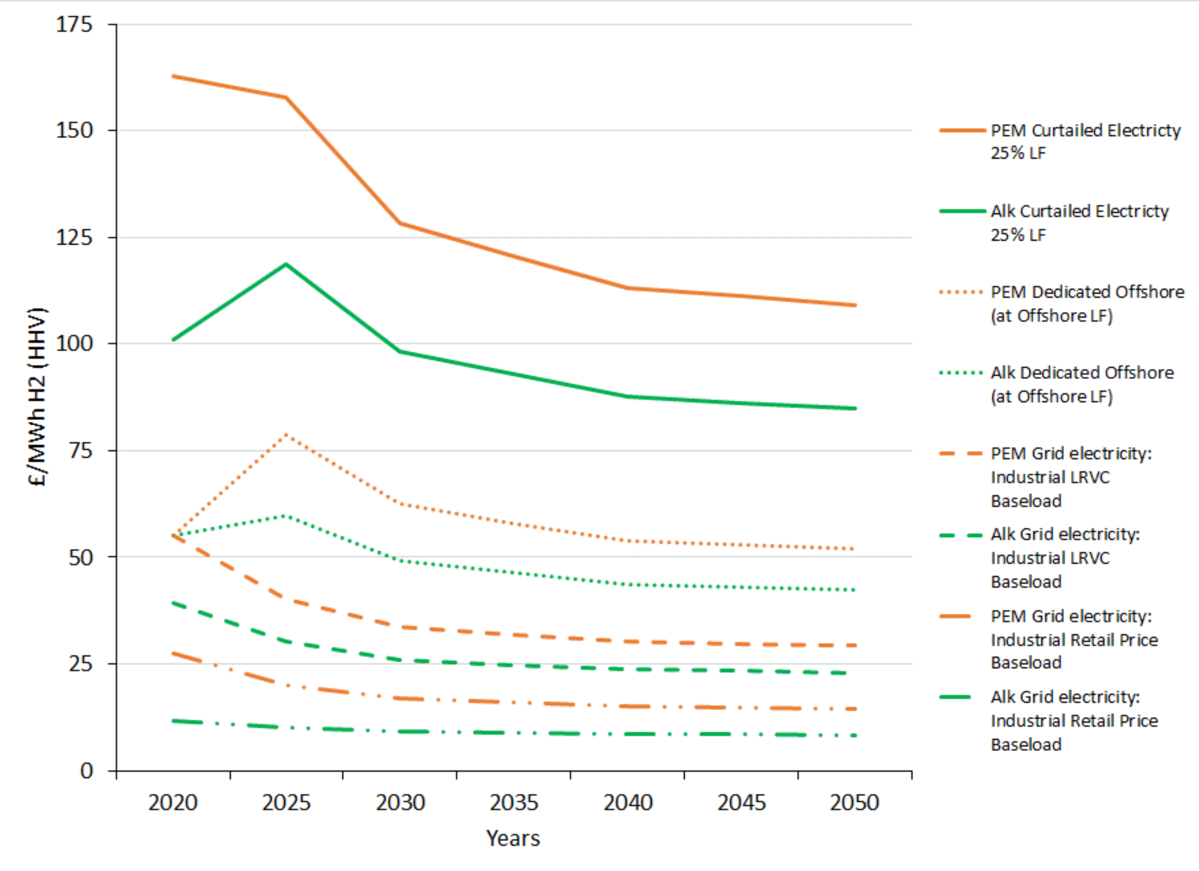

Figure 24 – Comparison of Capex estimates across different technology types at central fuel prices commissioning from 2020 to 2050, £/MWh H2 (HHV) [33].

3.3.3 Conclusions & recommendations

The hydrogen market is expected to a see a significant shift by 2050 towards green hydrogen production which will require further growth in renewable energy production. Various end users for hydrogen have been identified, but of significant interest to Alderney is the shift of international transport shipping to Hydrogen propulsion due to the island's proximity to the world busiest shipping lane.

There are still several barriers to the hydrogen industries growth which are being monitored by UK government through its hydrogen strategy. It is recommended that where possible Alderney monitors progress and engages with industry stakeholders to be able to identify the appropriate time hydrogen production could become feasible for the island.

The significant renewable energy resources surrounding the island could be of particular interest to hydrogen producers in future especially tidal because of its cyclical and predictable nature which perhaps currently cheaper alkaline electrolyser technology may prefer. We do recommend that the SoA monitor PEM technology however as its LCOH is expected to reduce to below that of Alkaline electrolysers.

4 RECOMMENDATIONS

This section concludes with our recommendations to SoA based on the findings of this scoping study. These are based on the extensive research we have undertaken and will help Alderney on the route towards improved energy security, reduced energy costs and lower CO_2 emissions into the future.

4.1 Short term (0-10 Years)

4.1.1 Electrical system

- Shortlist suppliers of refurbished wind turbines, commercial scale PV and battery storage designed for microgrid applications. As a first step, ORE Catapult can make connections with the companies that we spoke to as part of this study.
- Contact these suppliers and seek quotations. Direct discussions with AEL and these suppliers will help them gain maximum understanding of the current electricity system and how it is operated.
- Examine funding options for these types of renewable systems. For example could SoA/AEL fund or would it be more appropriate to let a private company develop and provide money to them via a PPA? Determine the capital available to invest in such scheme and work backwards from there to determine what scale of system would be appropriate. From our research, a sub 1MW wind turbine (refurbished) or solar PV system would be appropriate. A PPA is also desirable, as Alderney would not have to pay for the technology costs (as these would be fronted by a private company) but would still benefit from cost reduction due to less diesel usage.
- Work with suppliers to undertake a geospatial assessment: which parts of the island would be best for the technologies? This could coincide with installation of one or more met masts. Alderney should determine these, and designate specific land areas for renewable technologies, also potentially renting the land to developers and collecting a fee.
- We believe that Alderney should start with a sub 1MW pilot project, with no energy storage, to see how well this can be integrated with the existing energy system. This could be of the order of 100-300kW and will also help to educate and bring the population on side.
- We believe that Alderney should steer clear of offshore technologies at this time (e.g. offshore wind, floating solar, tidal stream) as these are typically larger scale, will be more expensive and require greater planning to achieve (e.g. offshore surveys, offshore cable laying are more complex and expensive).

4.1.2 Heating system

- A co-ordinated effort between the SoA and Alderney's residents to improve the insulation standard of the island's housing stock should be the top priority in the short-term with regards to domestic heating arrangements. Whatever heating systems are used in the future, improved insulation will ensure running costs and energy consumption are minimised.
- The SoA could provide financial support to assist residents in improving their home's insulation, particularly residents on lower income that would struggle to fund such home improvements alone. This support could be means tested and can play a role in alleviating fuel poverty on Alderney.

- Efforts should be made to identify properties where ST is of economic benefit for the occupants. This can be done more easily for public housing and properties that particularly stand to benefit are those which have higher than average hot water demands.
- ASHPs should be considered for households which already have suitable insulation in place and where occupants can afford the upfront costs of purchasing and installing such a system. However, caution must be taken when electrifying portions of Alderney's domestic heating demand so that grid stability is maintained.
- For all technologies and measures suggested in this scenario, a central procurement body, (e.g. a Community Energy Group) could be established which is responsible for the bulk ordering of improved heating solutions to drive down transport and labour costs associated with installation.

4.2 Medium Term (10-20 Years)

4.2.1 Electrical system

- We believe that SoA should build on any early successes achieved in the short term, targeting 3-4MW of renewable capacity on their grid (which could reduce diesel consumption by 80%).
- A mix of solar and onshore wind would be the preferred solution as these will work in tandem, reducing generation shortfalls and curtailment required.
- To achieve this level of renewable energy, energy storage will be needed. We recommend lithium-ion technology, although flow batteries could also be an option if the technology is commercially mature during this timeframe (this technology is introduced in the previous literature review that was supplied).
- While the grid should be able to handle 3-4MW of renewable capacity, we believe that Alderney should be thinking ahead to the long-term picture, whereby increased electrification in the heating system and hydrogen production could constrain the grid.
- In this timescale we don't think that Alderney could fully decarbonise. There will still be a need for diesel, albeit much lower, and so Alderney should revisit their import and vessel strategy, collaborating with Guernsey.
- In this timeframe we expect tidal stream energy to be coming down to more reasonable prices, potentially £90/MWh by 2030-32. This would still not be economic compared to onshore options, but we recommend that SoA follow developments in the industry closely, as by this time the leading device designs and turbine suppliers will be established. Typical offshore projects will take 5-10 years from initial scoping to commissioning, and so Alderney need to plan this far ahead of time.
- For Alderney to be able to attract project developers into its territorial waters a route to market (e.g., interconnector) and capacity to be able to provide an appropriate feed in tariff.
- Interconnector cost estimates suggest even the shortest route for an 800MW rated HVDC bi-polar connection would be approximately £352m, a far cheaper option would be to install a transmission cable link capable of either importing or exporting in a single direction. CAPEX estimates for this cable type linking to France and rated at 220 MW are £25m and it may be possible for Alderney to fund this in some way.

4.2.2 Heating system

- Without significant grid upgrades only a small portion of Alderney's domestic heating demand can be electrified without causing significant strain on the grid (~5% ASHP uptake), with even a 5% uptake increasing typical peak demands by over 50%.
- If the SoA do decide to pursue electrified renewable heating to some extent, co-ordination between themselves, AEL and island residents is crucial to ensure grid stability is maintained and annual peak demands can continue to be met without the threat of grid failures.

4.3 Long Term (20+ Years)

- Offshore technologies may well have come down in cost sufficiently to be able to develop projects in Alderney's waters. They will of course still require a route to market be that via an interconnector, transmission cable or perhaps even via hydrogen production on the island.
- Hydrogen and green hydrogen in particular is a fast growing and ever changing industry. Given Alderneys location alongside the world's busiest shipping lane there may be an opportunity for Alderney to become a producer of green hydrogen to fuel international shipping vessels. As such it is recommended the SoA monitor the industry closely and engage with relevant hydrogen production stakeholders.
- Alderneys significant tidal stream resource (up to 3GW) could be a significant source of renewable energy for the production of green hydrogen and would provide additional revenue to the island through seabed leasing.

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APPENDIX 1 INTERCONNECTORS SUPPLEMENT

Review of UK & EU interconnectors for CAPEX estimating

The electricity interconnectors are vital for the UK and EU to ensure the least-cost effective pathway to decarbonisation. By using physical interconnector links which will allow future relations to be opened up between the EU and the UK through collaborative negotiation, from building additional interconnectors. These systems are high voltage (HV) cross-border cables that link the separate electrical systems together, allowing the transmission and trade of electricity between countries. Great Britain's (GB) electricity market currently has 6 GW of electricity interconnector capacity using these high voltage direct current (HVDC) interconnectors that link GB electricity system to EU markets: these are IFA and IFA2 – 3 GW to France; BitNed – 1 GW to the Netherlands; Nemo Link – 1 GW to Belgium; Moyle – 500 MW to Northern Ireland; East West (EWIC) – 500 MW to the Republic of Ireland (Ofgem Interconnectors, 2021;Figure A1. 1; Table A1. 1). In 2018, the UK was a net importer of electricity across interconnectors providing 6% of the total electricity supply. Therefore, the UK government supports the development of an additional capacity circa 9 GW as part of the decarbonisation broader strategy to the energy mix between the devolved nations and wider EU countries (making up a third of the UK's energy demand).

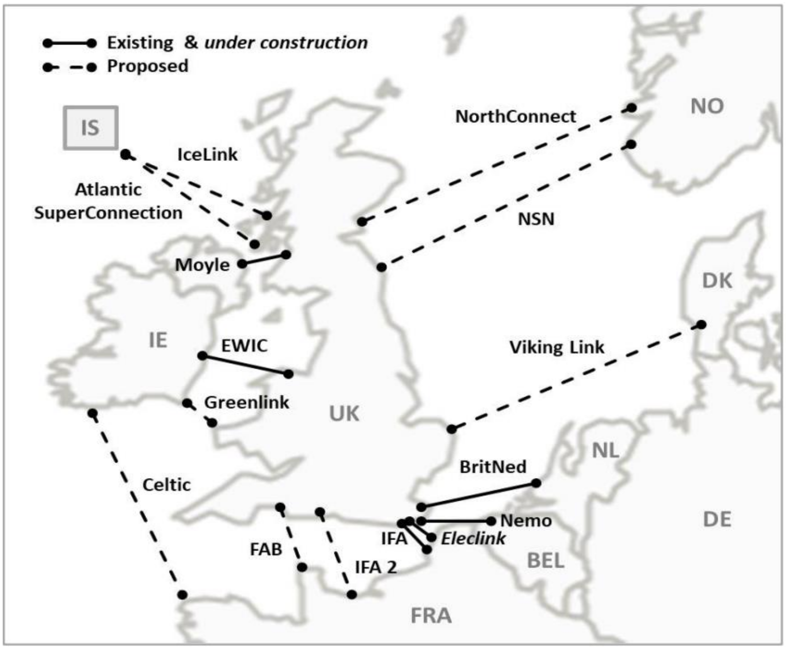

Figure A1. 1 – Existing and selected proposed electrical interconnector routes from the UK and the European Union (Ireland, and other EU/EEA countries) (UK-EU Electricity Interconnection: The UK's Low Carbon Future and Regional Co

Table A1. 1 – Interconnectors by project names representing a low carbon European regional future (UK-EU Electricity Interconnection: The UK's Low Carbon Future and Regional Cooperation after Brexit, 2019; Ofgem Interconnectors, 2021).

Project name	Year Comm.	Voltage HVDC (±kV)	Connecting Country	Developers	Capacity (MW)	Distance (km)	Cost (€) millions
NorNed	2008	450	NOR-NED	Statnett	700	580	600
BritNed	2011	450	Netherlands	NGIH & RTE	1,000	260	600
EWIC	2012	200	Ireland	EirGrid	500	261	410
Western-Link	2018	600	SCO-WAL	NGSP	2,200	422	1,180
Nemo-Link	2019	400	Belgium	NGIH & Elia	1,000	140	500
IFA2	2021	320	France	NGIH & RTE	1,000	204	826
NSL	2021	515	Norway	NGIH & Statnett	1,400	720	2,000
NordLink	2021	500	NOR-GER	Statnett	1,400	623	2,000
ElecLink	2022	320	France	Getlink	1,000	51	578
Viking-Link	2023	525	Denmark	NGIH & Energinet	1,400	760	1,300
Greenlink	2023	320	Ireland	Element Power	500	200	400
GridLink	2024	525	France	iCON	1,400	150	944
NeuConnect	2024	500	Germany	Meridiam Allianz	1,400	720	1,652
NorthConnect	2025	525	Norway	Agder Energi	1,400	650	1,534
FAB-Link	2025	320	France	TI & RTE	1,400	220	750
Celtic	2025	500	IRE-FRA	EirGrid & RTE	700	575	1,000

Limitation and assumptions

The States of Alderney should consider an interconnector as the lowest cost pathway to decarbonisation and increased security of electrical supply. Interconnectors increase electricity system flexibility by providing an alternative route to market for excess electricity during periods of low demand. This allows easier management to intermittent renewables to balance the system, i.e., demand fluctuations (UK-EU Electricity Interconnection: The UK's Low Carbon Future and Regional Cooperation after Brexit, 2019). Increased security of supply from interconnection can add to the overall balance of electricity supply, due to imports that could complement their domestic generation. The added flexibly to an interconnection is the bi-polar ability (energy in both directions), and almost instantaneous supply changing direction (from import to export) of electricity flow. The National Grid estimates that each additional GW of interconnector capacity coming online reduces the UK wholesale prices by 1-2%, saving consumers £1 bn per year for the future throughout the industry (Figure A1. 2).

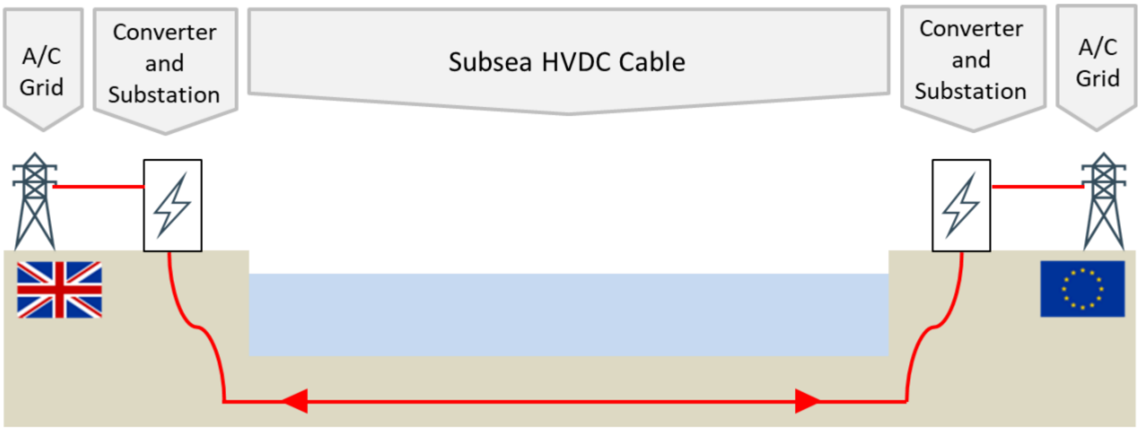

Figure A1. 2 – Illustration to the subsea HVDC interconnector overview to the technical specifications (UK-EU Electricity Interconnection: The UK's Low Carbon Future and Regional Cooperation after Brexit, 2019).

Offshore tidal resource and interconnector supply chain to Alderney

Interconnectors use HVDC connections because they can carry electricity more efficiently with fewer transmission losses (all dependent on distance versus HVAC transmission lines). Compared to an alternating current (AC) connection. Therefore, an approach for this scoping document was taken to create an assumption for Alderney through existing and proposed interconnector projects to understand the cost implications required. There are many factors that influence an interconnector development, for example, access, converter stations, HVDC subsea cables, routes implemented, EIAs, vessels, matching different supplies on either end, cost per kilometre, and capacity, to name a few (all having various limitations). In Figure A1. 3, the comparison is made between 16 named interconnector projects using the year commissioned or year planned compared to the capacity in MW; to build an assumption to the increase in capacity for the decade in question 2020-2030, to interconnectors. The next step shown in Figure A1. 4, was to compare cost in million Euro's for the same 16 named interconnector projects, compared to kilometres for each project. To show the relationship between the cost and distance to establish an accurate assumption to interconnector costing, for Alderney. The findings in both Figures, where significant in relation to MWs, cost, and distance covered in order to generate a straight-line trend to establish various distances for Alderney's interconnector option between France and then between Guernsey.

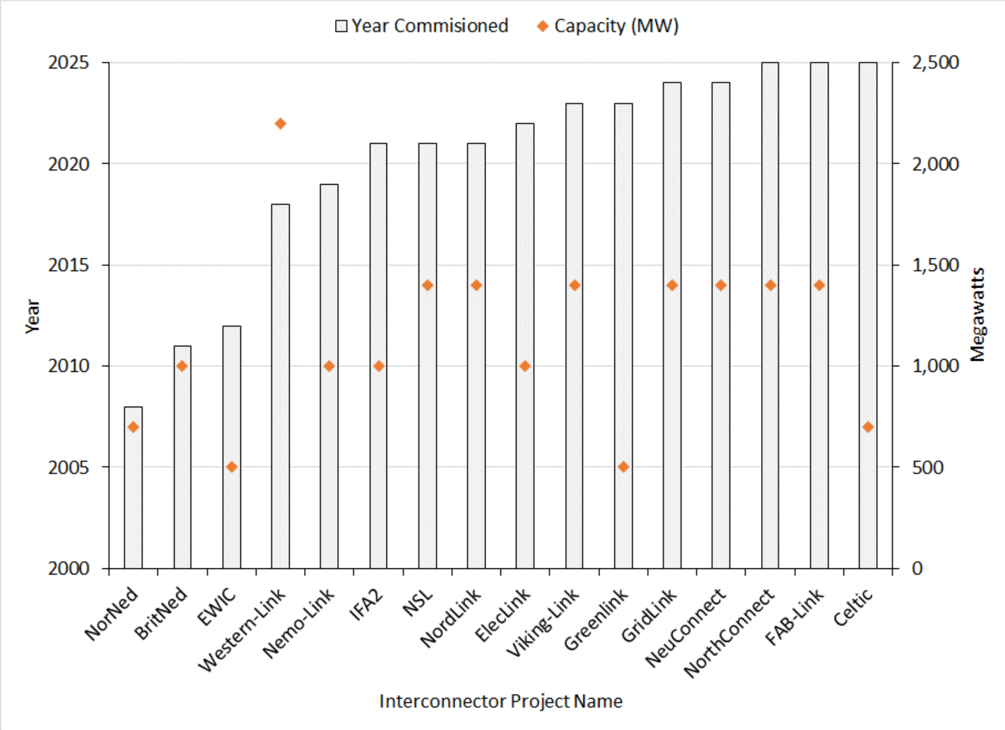

Figure A1. 3 – Statistical analysis as a bar graph to compare years versus megawatts to the 16 named interconnector projects for both in-service and planned developments.

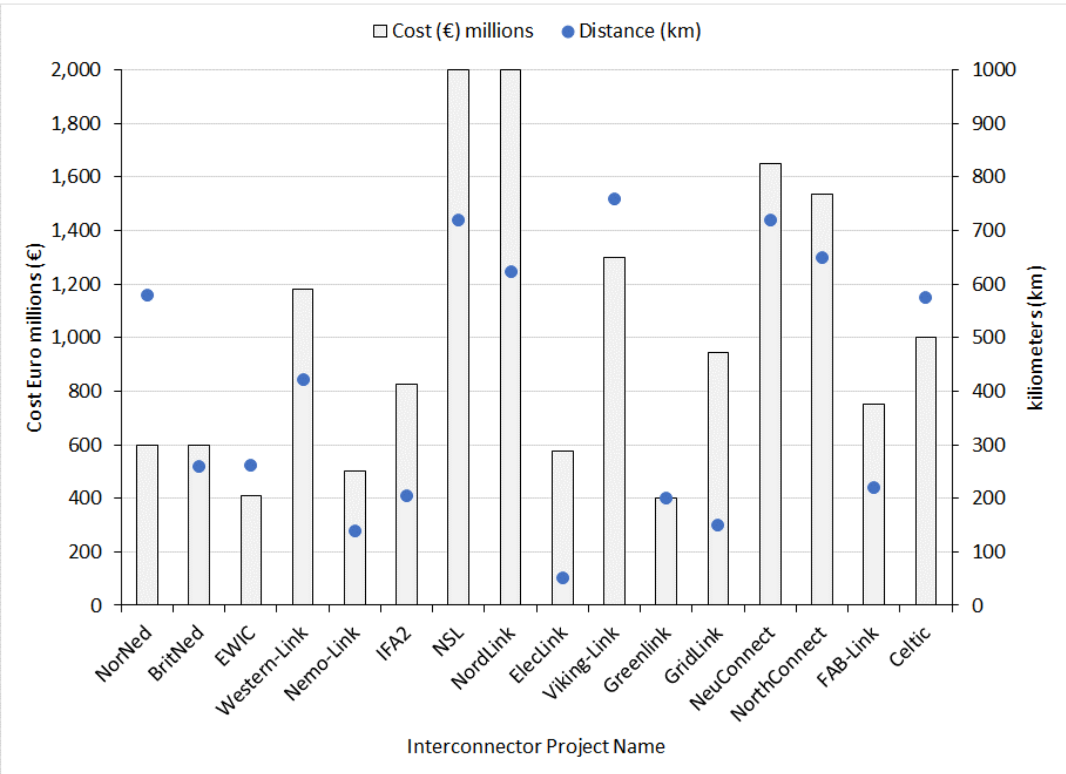

Figure A1. 4 – Statistical analysis as a bar graph to compare cost in Euro millions versus kilometres to the 16 named interconnector projects for both in-service and planned developments.

Conclusion

The final step was to compare the 16 named interconnector projects by means of a trend line to establish the cost in Euro millions versus the kilometres in a scatter plot format (Figure A1. 5). The assumptions were based on a HVDC cable voltage of ±350 kV, and a capacity of 800 MW to define total costs in full (including the respective converter station infrastructures). However, these values can be reduced to suit the long-term scenario in the Alderney objectives, which should include a bi-polar HVDC cable for a route to market. The cost for a HVDC bi-polar interconnector between Alderney and France, is assumed to be circa 352 million Euro for a 18 kilometre distance, and between Alderney and Guernsey, is assumed to be circa 384 million Euro for a 37 kilometre distance (Table A1. 2, Figure A1. 6, Figure A1. 7).

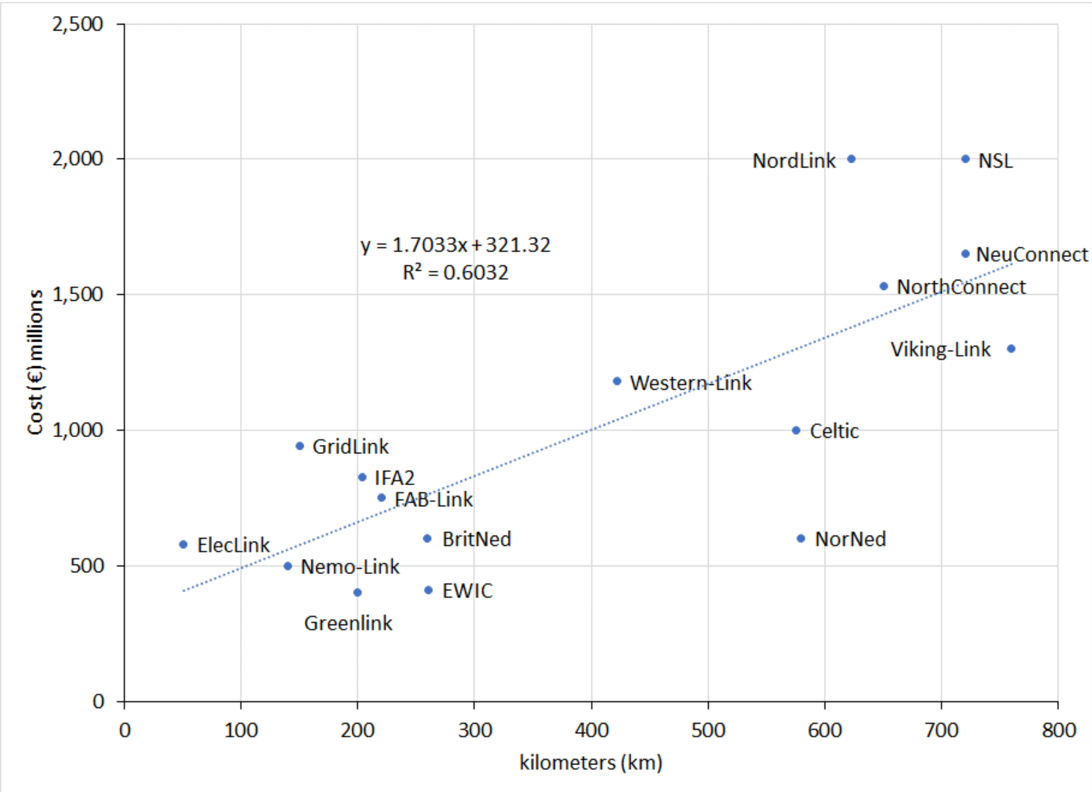

Figure A1. 5 – Statistical analysis as a scatter plot to compare cost in Euro millions versus kilometres to the 16 named interconnector projects for both in-service and planned developments to establish a trend line significance.

Table A1. 2 – Statistical significance to trend line, tabulated for a range in kilometres to express the (Euro) millions cost for two options to Alderney (to France-18 km, and Guernsey-37 km), including a subsea transmission link comparison expressed in (£) million.

Distance (km)	Cost (€) millions	Interconnector points HVDC ±350 kV, capacity 800 MW	Cost (£) millions	Subsea Transmission Link points HVAC ±220 kV, capacity 220 MW
10	338		14	
15	347		21	
18	**352**	**Alderney to France**	**25**	**Alderney to France**
20	355		27	
25	364		34	
30	372		41	
35	381		48	
37	**384**	**Alderney to Guernsey**	**51**	**Alderney to Guernsey**
40	389		55	
45	398		62	
50	406		69	
55	415		75	
60	424		82	

In comparison is the option of a HVAC transmission cable from a marine renewable energy resource that could harbour a reduction in cost significantly. For example, the "LT17 Orkney - Mainland Scotland HVAC 220 kV subsea transmission link (connection)", with a capacity of delivering a minimum of 220 MW. The total length of the subsea cable route is circa 53 km (Marine Scotland Information, 2022). Similar to Alderney the LT17 transmission link is centred around the development and connection of a significant volume of new renewable generation (abundant wind, marine and tidal energy resources). Electricity will be transmitted using a HVAC submarine cable technology. For this HVAC system the cable diameter is approximately 250 - 300 mm and weighs approximately 100 - 150 kg/m. Compared to the HVDC interconnector costs, the HVAC subsea transmission link would cost in the range in £70 million compared to the interconnection average cost previously discussed of in excess of 350 million Euro's (Marine Scotland Information, 2022). Therefore the cost for a HVAC transmission link between Alderney and France, from the figures of the Scottish Orkney-Mainland subsea cable – is assumed to be circa £25 million for a 18 kilometre distance, and between Alderney and Guernsey, is assumed to be circa £51 million for a 37 kilometre distance.

Finally, from the research undertaken, the advice would be for Alderney to investigate interconnector options for their best route to market and energy security beyond 2040.

Figure A1. 6 – Map representing a HVDC subsea interconnector route between Alderney and France at 20 kilometres

Figure A1. 7 – Map representing a HVDC subsea interconnector route between Alderney and Guernsey at 37 kilometres.

APPENDIX 2 SHORT TERM ELECTRICITY SYSTEM MODELLING – DETAILED RESULTS SUPPLEMENT

S.1 Current system

Figure A2. 1 – Key results from the HOMER simulation. Top: Net present cost by system component. Top mid: Net present cost by cost type. Bottom mid: Discounted cash flow. Bottom: monthly electricity production by source.

S.2 Early new wind

Figure A2. 2 – Key results from the HOMER simulation. Top: Net present cost by system component. Top mid: Net present cost by cost type. Bottom mid: Discounted cash flow. Bottom: monthly electricity production by source.

S.3 Early refurbished wind

Figure A2. 3 – Key results from the HOMER simulation. Top: Net present cost by system component. Top mid: Net present cost by cost type. Bottom mid: Discounted cash flow. Bottom: monthly electricity production by source.

S.4 Early solar

Figure A2. 4 – Key results from the HOMER simulation. Top: Net present cost by system component. Top mid: Net present cost by cost type. Bottom mid: Discounted cash flow. Bottom: monthly electricity production by source.

S.5 High renewable

Figure A2. 5 – Key results from the HOMER simulation. Top: Net present cost by system component. Top mid: Net present cost by cost type. Bottom mid: Discounted cash flow. Bottom: monthly electricity production by source.

S.6 High renewable with battery

Figure A2. 6 – Key results from the HOMER simulation. Top: Net present cost by system component. Top mid: Net present cost by cost type. Bottom mid: Discounted cash flow. Bottom: monthly electricity production by source.

M.1 Lowest cost – baseline battery

Figure A2. 7 – Key results from the HOMER simulation. Top: Net present cost by system component. Top mid: Net present cost by cost type. Bottom mid: Discounted cash flow. Bottom: monthly electricity production by source.

M.2 Lowest cost – "cheap" battery

Figure A2. 8 – Key results from the HOMER simulation. Top: Net present cost by system component. Top mid: Net present cost by cost type. Bottom mid: Discounted cash flow. Bottom: monthly electricity production by source.

M.3.1 Lowest cost – low fuel cost

Figure A2. 9 – Key results from the HOMER simulation. Top: Net present cost by system component. Top mid: Net present cost by cost type. Bottom mid: Discounted cash flow. Bottom: monthly electricity production by source.

M.3.2 Lowest cost – high fuel cost

Figure A2. 10 – Key results from the HOMER simulation. Top: Net present cost by system component. Top mid: Net present cost by cost type. Bottom mid: Discounted cash flow. Bottom: monthly electricity production by source.

APPENDIX 3 HYDROGEN MARKET ANALYSIS SUPPLEMENT

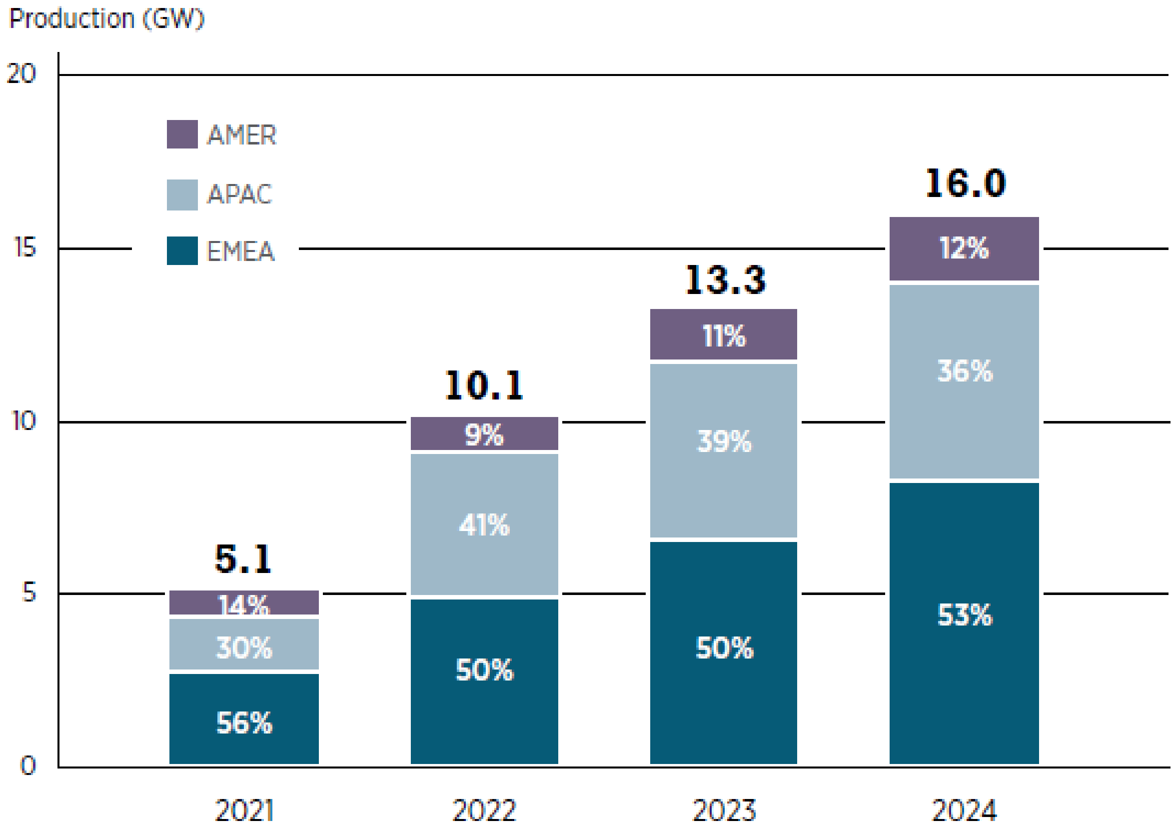

Figure A3. 1 – Estimated global electrolyser manufacturing capacity 2021-2024 (IRENA Geopolitics of the Energy Transformation, 2022).

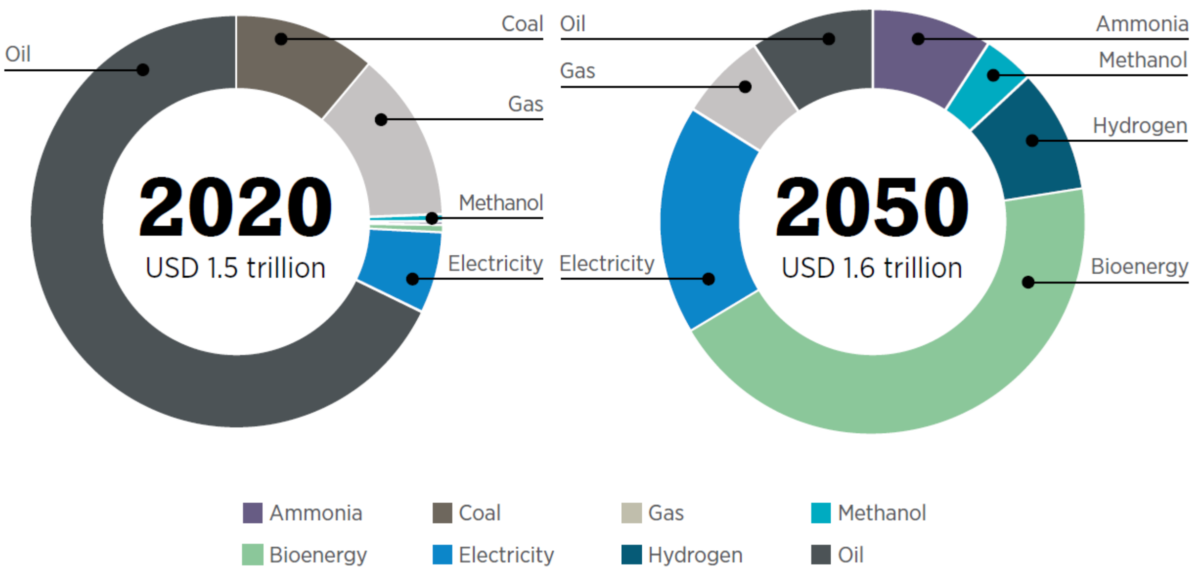

Figure A3. 2 – Shifts in the value of trade in energy commodities, 2020 to 2050 (IRENA Geopolitics of the Energy Transformation, 2022).

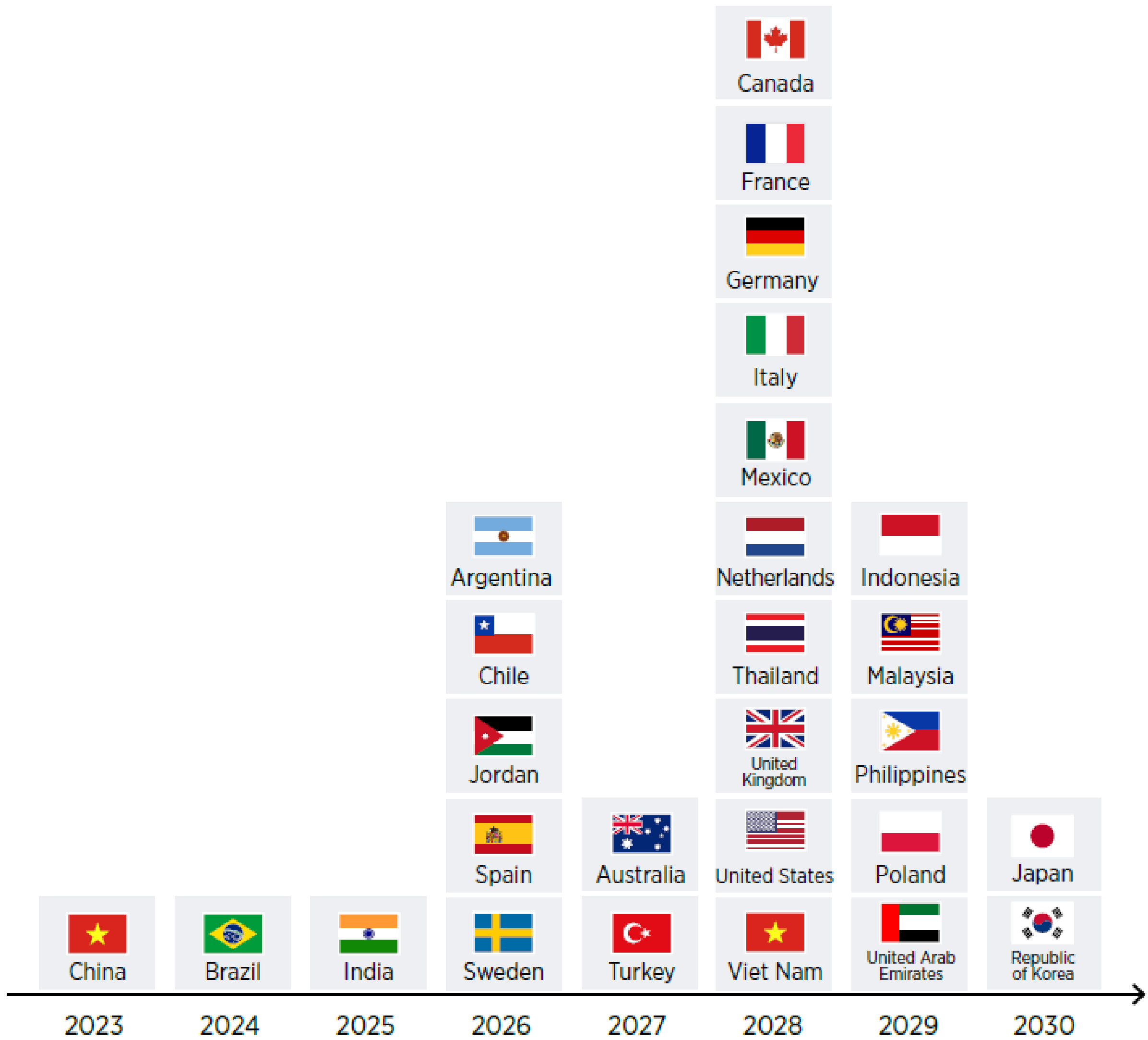

Figure A3. 3 – Countries where green hydrogen could become cheaper than blue hydrogen (IRENA Geopolitics of the Energy Transformation, 2022).

APPENDIX 4 SUPPLIER ENGAGEMENT

Table A4. 1 – List of the suppliers that we spoke to as part of our market research.

Company Name	Technology	Company Website
Tesvolt	Battery	https://www.tesvolt.com/en/
Edina	CHP	https://www.edina.eu/
Solar Southwest	Solar PV	https://solarsouthwest.co.uk/
Solar UK	Solar Thermal	http://www.solaruk.com/
Distributed Generation Limited (DistGen)	Wind	www.distgen.co
Wind Energy Solutions	Wind	https://windenergysolutions.nl/

CATAPULT
Offshore Renewable Energy
Development Services Ltd

GLASGOW

ORE Catapult
Inovo
121 George Street
Glasgow
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BLYTH

National Renewable
Energy Centre
Offshore House
Albert Street, Blyth
Northumberland
NE24 1LZ

+44 (0)1670 359555

LEVENMOUTH

Fife Renewables Innovation
Centre (FRIC)
Ajax Way
Leven
KY8 3RS

+44 (0)1670 357649

GRIMSBY

O&M Centre of Excellence
ORE Catapult, Port Office
Cleethorpe Road
Grimsby
DN31 3LL

+44 (0)333 004 1400

ABERDEEN

Subsea UK
30 Abercrombie Court
Prospect Road, Westhill
Aberdeenshire
AB32 6FE

07436 389067

CORNWALL

Hayle Marine Renewables
Business Park
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Hayle, Cornwall
TR27 4DD

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PEMBROKESHIRE

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Centre of Excellence (MEECE)
Bridge Innovation Centre
Pembrokeshire Science
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