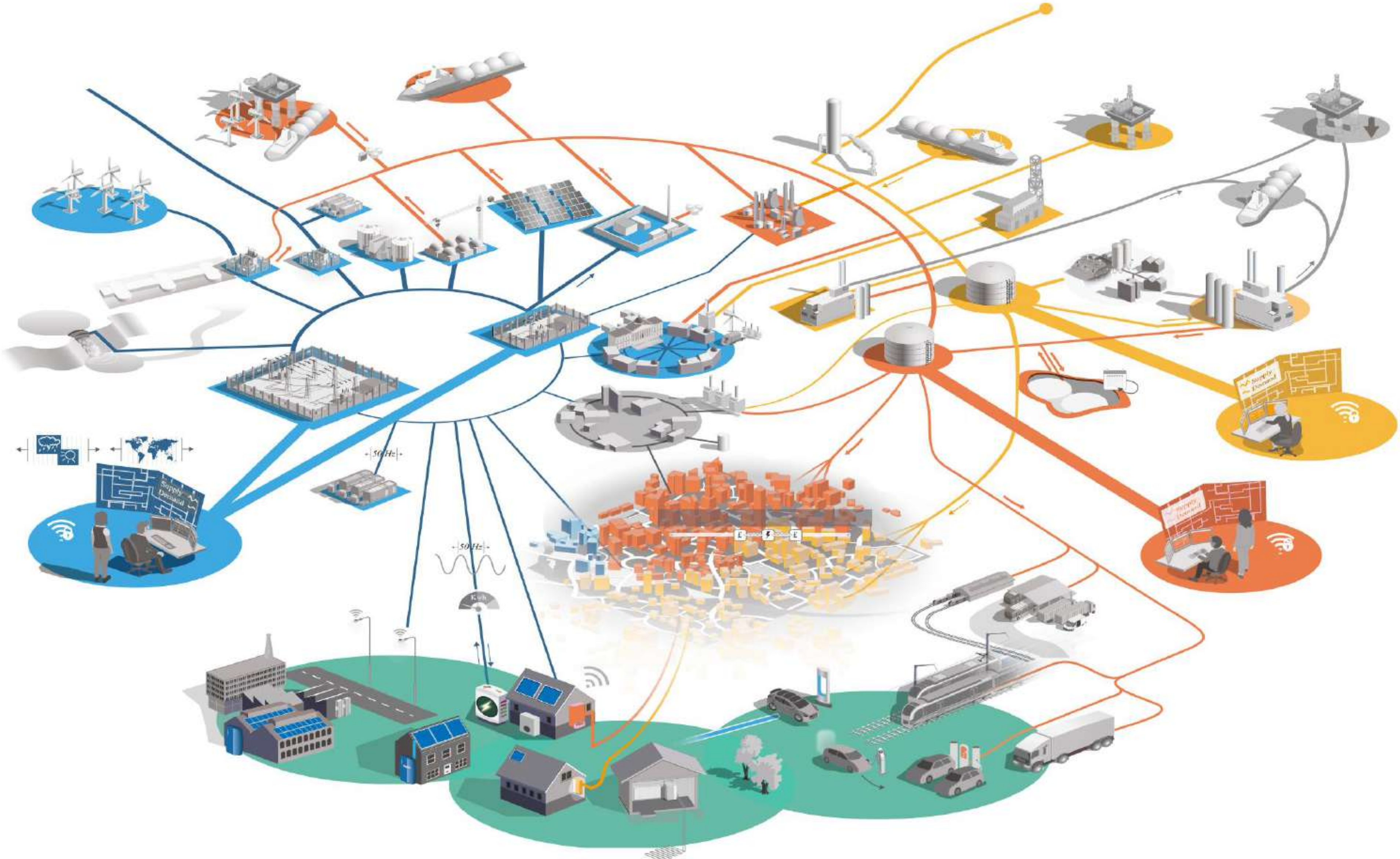
Isle of Man - Future Energy Scenarios

JULY 2021

FINAL REPORT

BUSINESS AND INVESTOR ADVISORY



ARUP

Dear Sir, Madam,

Isle of Man – Future Energy Scenarios

This report has been prepared specifically for and under the instructions and requirements of the Isle of Man Government under an appointment dated 16 December 2020, and a subsequent extension agreed on 03 June 2021, in connection with the development of Future Energy Scenarios.

This report is prepared for use and reliance by our Client only. No third party is entitled to rely on this report. We do not in any circumstances accept any duty, responsibility or liability to any third party whatsoever (including retail investors whether by bond issue or otherwise) who has relied on this report. Accordingly, we disclaim all liability of whatever nature (including in negligence) to any third party other than to our Client or to any third party with whom we have agreed and signed a reliance letter and such liability is subject always to the terms of our Appointment with the Client and the reliance letter with the third party.

Yours faithfully

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Basis of preparation

In preparing this report we have relied on information provided by others and we do not accept responsibility for the content, including the accuracy and completeness, of such information. In no circumstances do we accept liability in relation to information provided by others.

We emphasise that any forward-looking projections, forecasts, or estimates are based upon interpretations or assessments of available information at the time of writing. The realisation of the prospective financial information is dependent upon the continued validity of the assumptions on which it is based. Actual events frequently do not occur as expected, and the differences may be material. For this reason, we accept no responsibility for the realisation of any projection, forecast, opinion or estimate.

Findings are time-sensitive , relevant only to current conditions at the time of writing. We will not be under any obligation to update the report to address changes in facts or circumstances that occur after the date of our report that might materially affect the contents of the report or any of the conclusions set forth therein.

No person other than our Client and any party to whom reliance has been expressly permitted by us pursuant to a reliance letter may copy (in whole or in part), use or rely on the contents of this report without our prior written permission. Any copying or use of this report (in whole or in part) whatsoever shall be accompanied by or incorporate this notice at all times.

We accept no responsibility for, and have not authorised, the contents of any report, prospectus, supplementary prospectus, listing particulars, supplementary listing particulars, presentation or other document or communication in respect of the sale, acquisition, offering or transfer of any shares or securities or interest in them, whether on the primary or secondary market or otherwise, which uses, includes or incorporates any report, deliverable or information, or any element thereof, prepared by us under or in connection with our Appointment.

The scenarios presented in this report are specific to the Isle of Man, and have been developed based on the constraints and requirements identified by our Client, and assumptions agreed upon with our Client. The scenarios are likely to change, if the underlying constraints, requirements and assumptions change. These scenarios are not replicable for other locations, including other island jurisdictions.

This report is based on information gathered from the following sources:

- Review of publicly available information (such the National Grid Future Energy Scenarios (2020) and the BEIS Cost of Generation Report (2020))
- Information provided in the virtual data room (VDR) by the Client and other stakeholders
- Virtual meetings and workshops held with the client and wider stakeholders, including Manx Utilities Authority (MUA)
- Information shared by the Client during virtual meetings, workshops and via emails
- Responses to the Request for Information (RFI)

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0.1 Table of Contents

Outline of the report

This report presents four Future Energy Scenarios for the Isle of Man, aimed at transitioning the island's electricity network to a net zero emissions network by 2050.

SUMMARY & MAIN POINTS

- The Isle of Man (IoM) government has legislated to reduce its greenhouse gas (GHG) emissions to net zero by 2050. Achieving this target, requires transitioning the existing electricity network to a low or zero carbon system.
- Arup is assisting the IoM government with developing a set of future scenarios for the generation and transmission of electricity on the island. The scenarios are aimed at achieving 75% generation from renewable or carbon neutral sources by 2035, whilst being cognisant of the target to achieve net zero emissions by 2050.
- As part of this, Arup has assessed the technical and financial considerations for each option. Additionally, Arup has prepared a roadmap, and identified key next steps to inform the island's energy transition. This report summarises the findings of our work and the key recommendations:

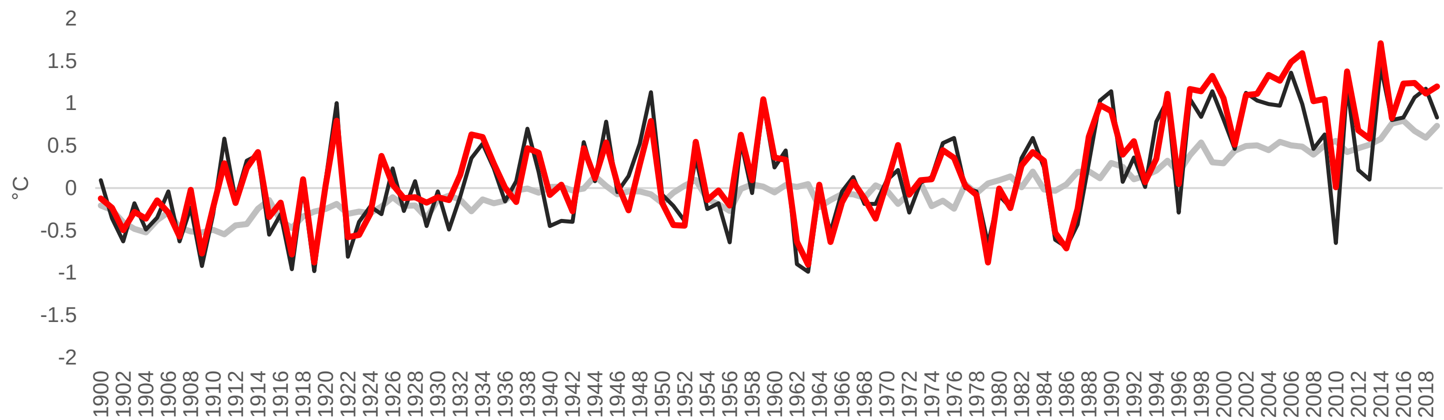
1. SUMMARY OF KEY FINDINGS

In response to the global climate emergency, the Isle of Man Government has legislated to reduce its emissions to net zero by 2050. This target has implications for both electricity demand and generation mix.

GLOBAL, UK AND THE ISLE OF MAN TEMPERATURE ANOMALY: 1900-2019 (°C), BASE 1961-1990

LEGEND

- Global Temperature Anomaly
- UK Temperature Anomaly
- IoM Temperature Anomaly

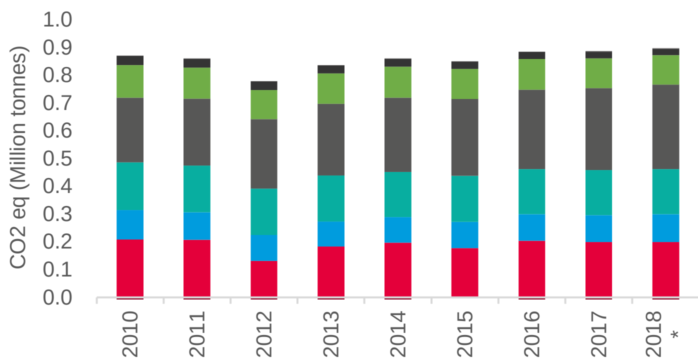


TOTAL EMISSIONS LEGEND

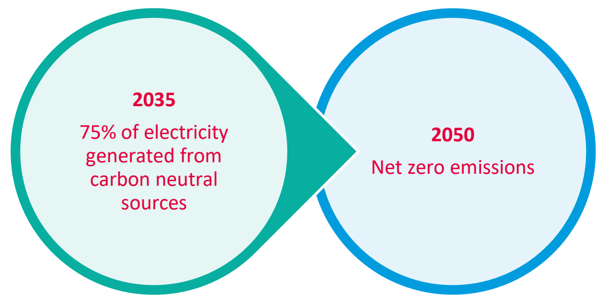
- LAND USE CHANGE
- WASTE MANAGEMENT
- AGRICULTURE
- RESIDENTIAL
- TRANSPORT
- BUSINESS
- ELECTRICITY GENERATION

*2018 electricity generation emissions data is the only data point which has been corrected by the IoM Government / Aether. All other data is currently being recalculated.

TOTAL EMISSIONS (CO2 EQ. MILLION TONNES)



EMISSION REDUCTION TARGETS FOR IOM



Evolution of electricity demand

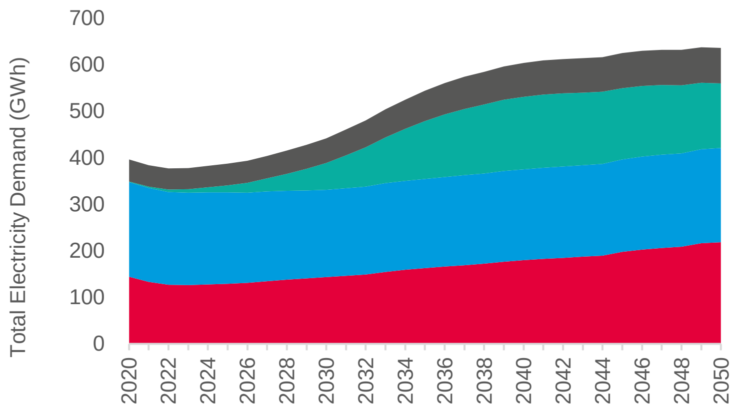
The electricity demand on the IoM is projected to increase. Long term projections vary depending on the assumed variations in energy efficiency gains, electrification of heat and uptake of electric vehicles.

LEGEND

- Losses
- Residential Demand
- I&C Demand
- Transport Demand

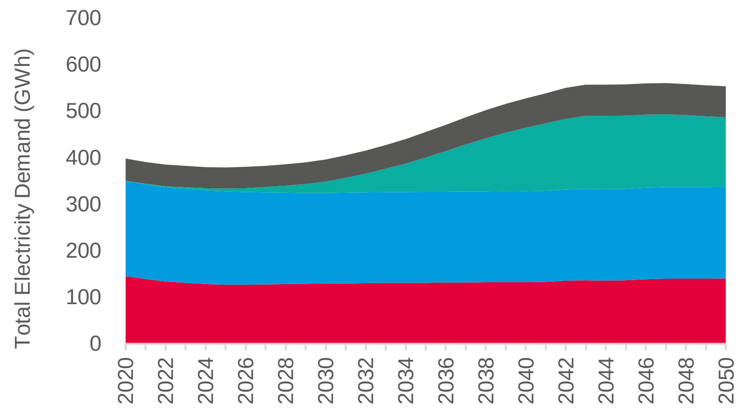
*Note: losses represent 12% of total demand

CONSUMER TRANSFORMATION TOTAL ELECTRICITY DEMAND (INCLUDING LOSSES)*



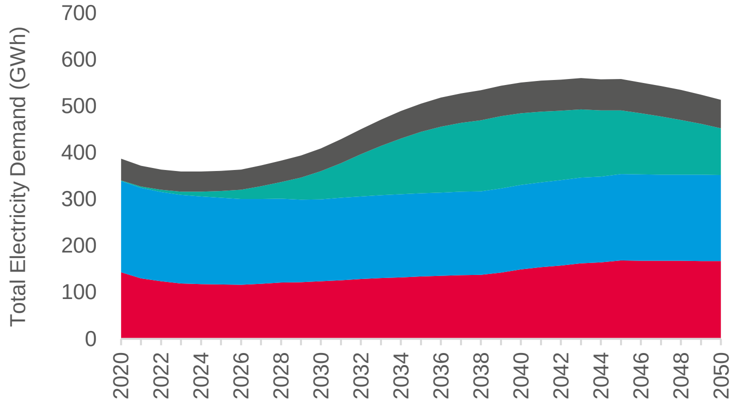
SOURCE: ARUP ANALYSIS

SYSTEM TRANSFORMATION TOTAL ELECTRICITY DEMAND (INCLUDING LOSSES)*



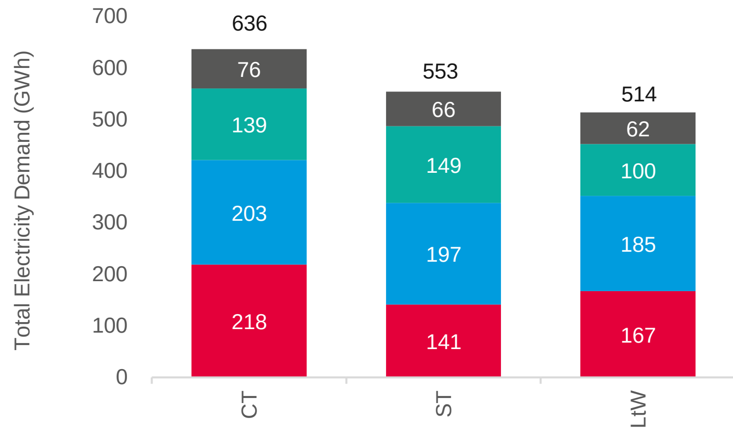
SOURCE: ARUP ANALYSIS

LEADING THE WAY TOTAL ELECTRICITY DEMAND (INCLUDING LOSSES)*



SOURCE: ARUP ANALYSIS

TOTAL ELECTRICITY DEMAND 2050 BY SCENARIO (INCLUDING LOSSES)*



SOURCE: ARUP ANALYSIS

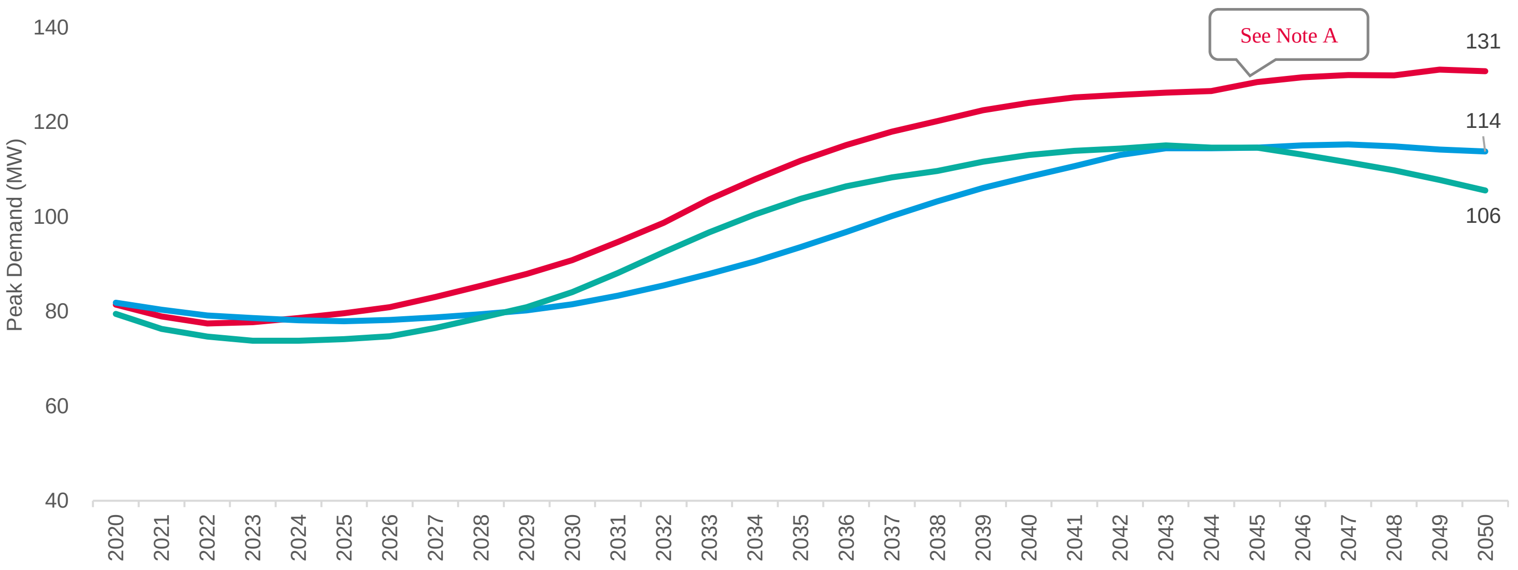
The peak demand on the IoM is also expected to increase, following a similar pattern to the total annual demand projections.

LEGEND

- Consumer Transformation
- System Transformation
- Leading the Way

Note A: Small steps in the consumer transformation demand profile beyond 2040 is linked to significant yearly increases in the conversion of existing non-electric heating customers to electric heating (e.g between 2044 and 2045).

PROJECTED PEAK DEMAND (INCLUDING LOSSES) (2020F-2050F)



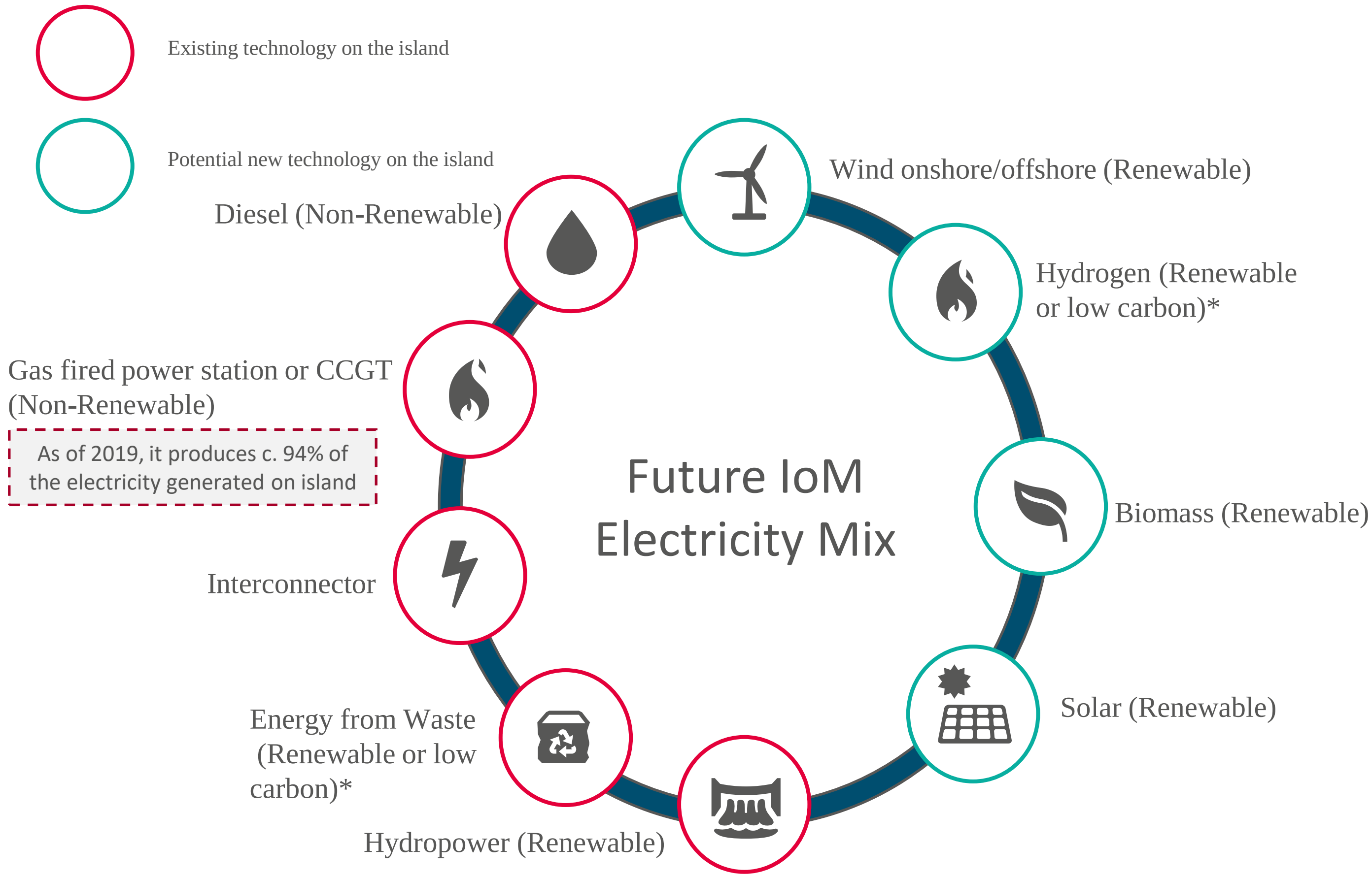
SOURCE: ARUP ANALYSIS

- Initially, peak demand falls slightly across all scenarios, due to energy efficiency gains. However, from 2025 onwards, electricity demand begins to increase due to increased electrification of heating and electrification of transport.
- The **consumer transformation scenario** sees the fastest and largest increase in peak demand, as this scenario is associated with the greatest extent of electrification and greatest number of electric vehicles. As a result, the peak demand will be highest under this scenario to meet demand from consumers charging EVs and using electric heating. In the consumer transformation scenario, peak demand increases 66% between 2019 and 2050, up to a peak demand of 131 MW.
- The **system transformation scenario** has the central overall final peak demand, with peak demand in 2050 reaching 114 MW, an increase of 44% from 2019.
- The **leading the way scenario** has the lowest overall peak demand, resulting from the greatest energy efficiency gains across all sectors and decreasing demand the electric vehicles due to the rise in autonomous vehicles and active transport from 2040. In the leading the way scenario, peak demand reaches 106 MW by 2050, an increase of 34% from 2019.

Through a combination of workshops and assessments, a short list of technologies that form part of the island's future electricity generation mix has been identified. This mix is comprised of existing and new technologies.

NOTE

*EfW and Hydrogen-fuelled power plants can be either renewable (zero carbon) or low carbon depending on the biogenic content of the waste (for the EfW plant) and the method used for producing hydrogen and capturing residual emissions (if any).



SOURCE: ARUP ANALYSIS

Based on the shortlisted technologies, and the key constraint around resilience requirements, Arup has modelled the evolution of four generation mix scenarios to meet the island's climate targets.

*Biomass has been used for the purpose of this modelling exercise and as agreed with the IoM Climate Change Transformation Team. However, biomass fuel could potentially be replaced with another carbon neutral biofuel (e.g., biogas or biodiesel).

**The CCGT asset life could potentially be extended further, but would require refurbishment at a cost.

Peaking: the occasional running of a plant to meet periods of high peak demand.

RENEWABLES OR LOW CARBON TECHNOLOGIES

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Technology	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Interconnector	**1 x interconnector** **Existing** 60 MW AC reaches end of life at end of 2040 (based on information provided by MUA). **Existing** AC interconnected is replaced with a 140 MW DC interconnector after retirement	**2 x interconnectors** **New 140 MW DC** interconnector comes online in 2028. **Existing** 60 MW AC interconnector reaches end of life in 2040 (based on information provided by MUA). **Existing** replaced with another 140 MW DC interconnector.	**2 x interconnectors** **New 140 MW DC** interconnector comes online in 2028. **Existing** 60MW AC extended at least till 2050. (this will require upgrades and potential commercial and contractual negotiations).	**4 x interconnectors in total** **3 x New 70 MW DC** interconnectors come online between 2028 and 2032. **Existing** 60MW AC extended at least till 2050. (this will require upgrades and potential commercial and contractual negotiations).
Offshore Wind	Model decision	Model decision	Model decision	Model decision
Onshore Wind	Model decision	Model decision	Model decision	Model decision
Solar PV	Model decision	Model decision	Model decision. 50% of new residential, commercial and industrial customers assumed to install behind-the-meter solar PV.	Model decision. 50% of new and existing residential, commercial and industrial customers assumed to install behind-the-meter solar PV.
Biomass*	Biomass built to ensure N-1 resilience in capacity terms, but will operate as a peaking plant due to fuel constraints and interconnection being available for generation.	Biomass built to ensure N-1 resilience in capacity terms, but will operate as a peaking plant due to fuel constraints and interconnection being available for generation.	Biomass built to ensure N-1 resilience in capacity terms, but will operate as a peaking plant due to fuel constraints and interconnection being available for generation.	No biomass
Hydrogen CCGT	Model decision	Model decision	Model decision	Model decision
Hydropower	No capacity expansion possible	No capacity expansion possible	No capacity expansion possible	No capacity expansion possible
EfW	No capacity expansion possible	No capacity expansion possible	No capacity expansion possible	No capacity expansion possible
CCGT	Can't increase beyond existing capacity. Reaches end of asset life by 2031 (based on information provided by MUA). **	Can't increase beyond existing capacity. Reaches end of asset life by 2031 (based on information provided by MUA). **	Can't increase beyond existing capacity. Reaches end of asset life by 2031 (based on information provided by MUA). **	Can't increase beyond existing capacity. Reaches end of asset life by 2031 (based on information provided by MUA). **
Diesel	Can't increase beyond existing capacity. Reaches end of asset life by 2027 (based on information provided by MUA).	Can't increase beyond existing capacity. Reaches end of asset life by 2027 (based on information provided by MUA).	Can't increase beyond existing capacity. Reaches end of asset life by 2027 (based on information provided by MUA).	Can't increase beyond existing capacity. Reaches end of asset life by 2027 (based on information provided by MUA).

SOURCE: ARUP ANALYSIS AND MUA

Installed Capacity(MW) and Generation(GWh): Scenario 1

S1

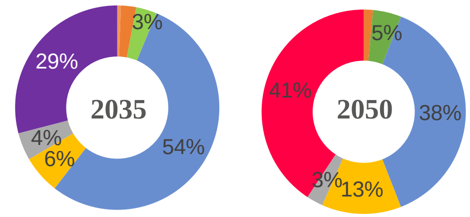
Scenario 1 has nearly 60% on-island renewable capacity, including biomass, by 2050. Whilst there is significant biomass capacity in this scenario, the generation from this plant is projected to reduce over time.

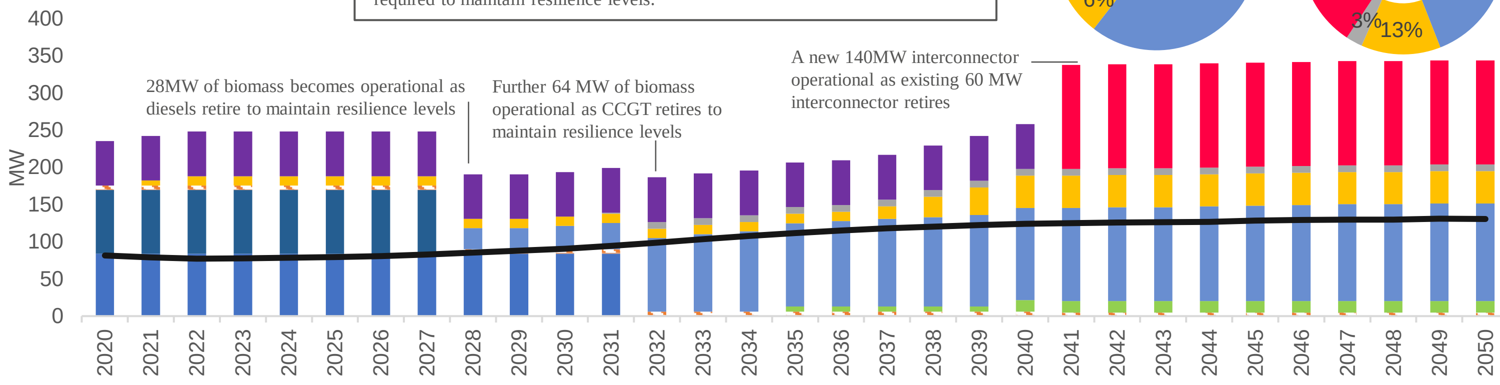
LEGEND

- CCGT
- DIESEL
- HYDROPOWER
- ENERGY FROM WASTE (EFW)
- ONSHORE WIND
- BIOMASS*
- SOLAR
- ENERGY STORAGE
- OFFSHORE WIND
- INTERCONNECTOR (EXISTING)
- INTERCONNECTOR (NEW)
- PEAK DEMAND (CT)
- GB TO IOM

INSTALLED CAPACITY (MW)

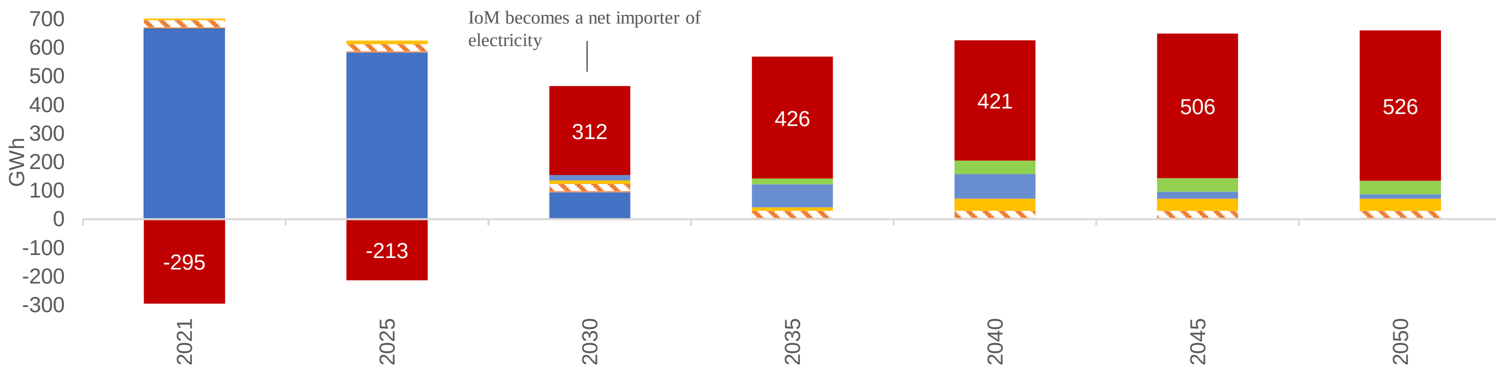
There is flexibility in this scenario to bring the new 140 MW interconnector forward in the timeline or extend the existing interconnector or CCGT's life. This would have implications on the quantity and timing of the biomass required to maintain resilience levels.





Further biomass becomes operational throughout the scenario from 2028 to maintain resilience levels in response to rising peak demand

GENERATION (GWH)



SOURCE: ARUP ANALYSIS

*Biomass could potentially be replaced with another carbon neutral biofuel

Summary of Key Findings

Installed Capacity(MW) and Generation(GWh): Scenario 2

S2

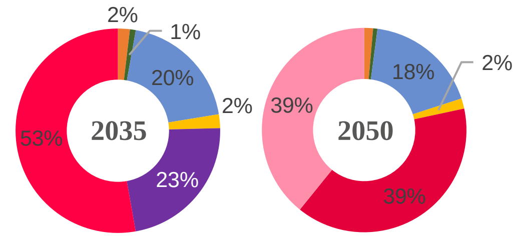
Scenario 2 has approximately 20% on-island renewable capacity, including biomass, by 2050. The presence of two interconnectors in this scenario provides comparatively greater resilience and significantly reduced reliance on biomass.

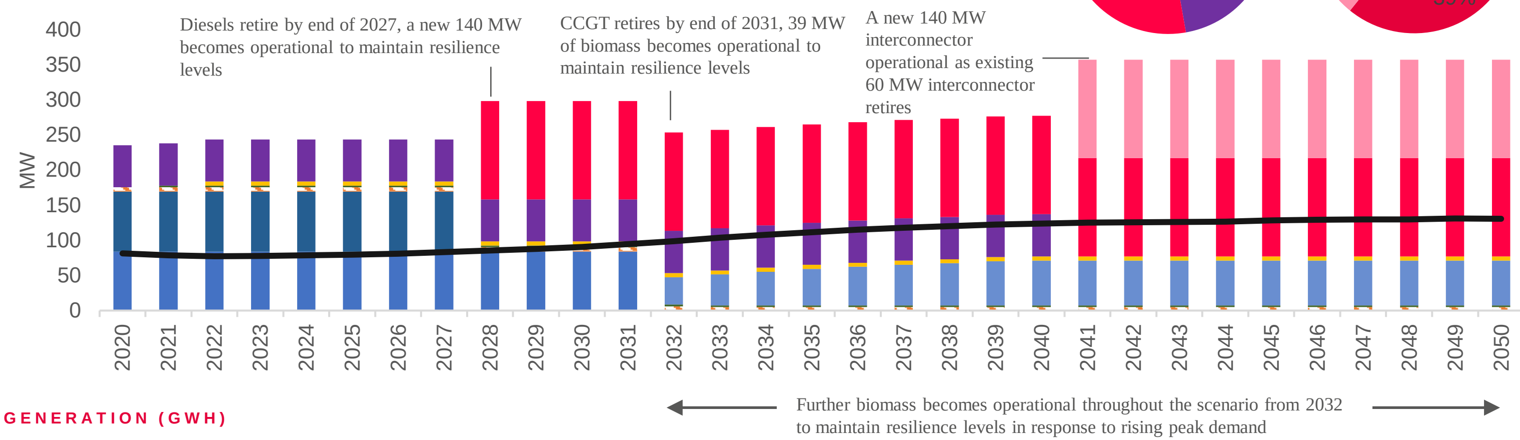
LEGEND

- CCGT
- DIESEL
- HYDROPOWER
- ENERGY FROM WASTE (EFW)
- ONSHORE WIND
- BIOMASS*
- SOLAR
- ENERGY STORAGE
- INTERCONNECTOR (EXISTING)
- INTERCONNECTOR (NEW 1)
- INTERCONNECTOR (NEW 2)
- PEAK DEMAND (CT)
- GB TO IOM

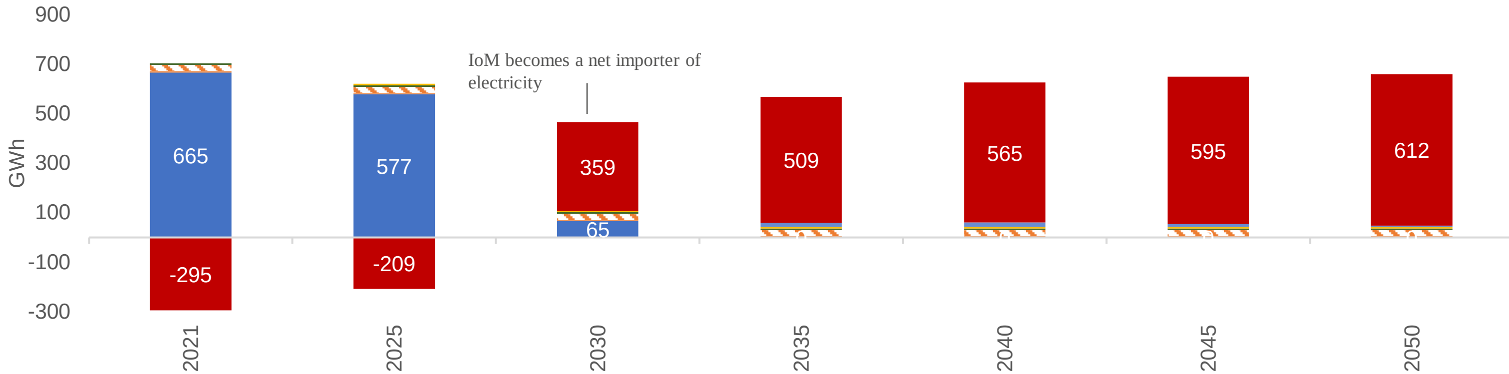
INSTALLED CAPACITY (MW)

There is flexibility in this scenario to alter the timings of new interconnectors becoming operational and the retirement dates of the existing CCGT and interconnector. This would have implications on the quantity and timing of the biomass required to maintain resilience levels.





GENERATION (GWH)



SOURCE: ARUP ANALYSIS

*Biomass could potentially be replaced with another carbon neutral biofuel

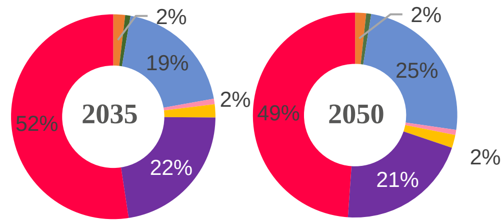
Installed Capacity(MW) and Generation(GWh): Scenario 3

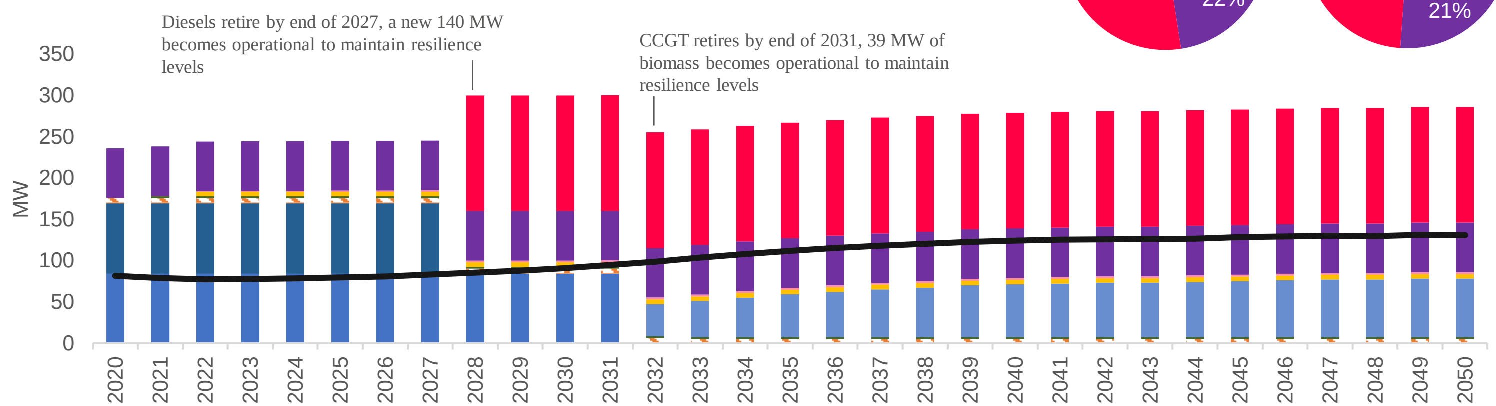
S3

Scenario 3 has approximately 30% on-island renewable capacity, including biomass, by 2050. The two interconnectors in this scenario also help reduce the reliance on biomass and increase overall resilience level.

INSTALLED CAPACITY (MW)

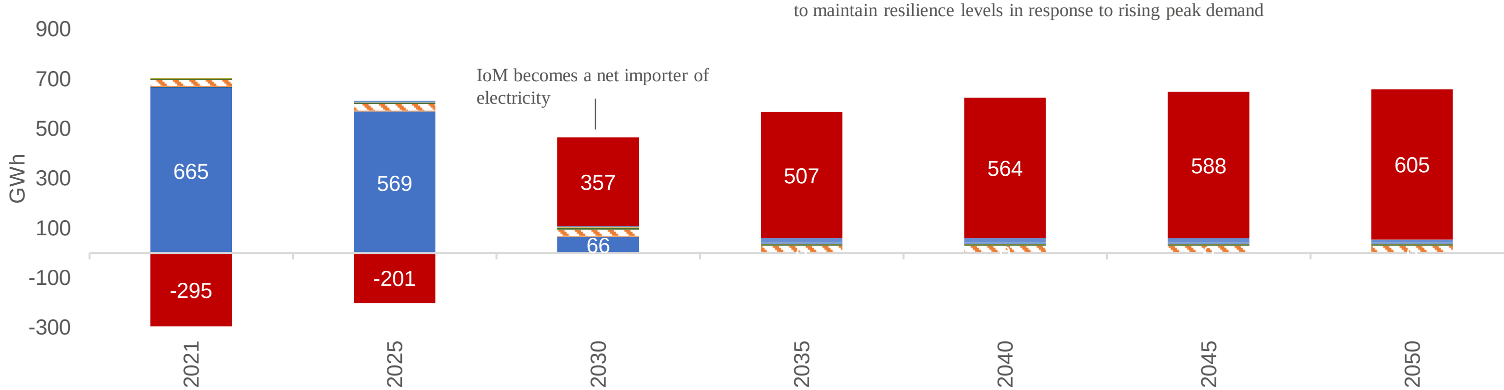
There is flexibility in this scenario to alter the timings of the new interconnector becoming operational and the retirement dates of the existing CCGT.This would have implications on the quantity and timing of the biomass required to maintain resilience levels.





GENERATION (GWH)

Further biomass becomes operational throughout the scenario from 2032 to maintain resilience levels in response to rising peak demand



LEGEND

- CCGT
- DIESEL
- HYDROPOWER
- ENERGY FROM WASTE (EFW)
- ONSHORE WIND
- BIOMASS*
- SOLAR
- ENERGY STORAGE
- OFFSHORE WIND
- INTERCONNECTOR (EXISTING)
- INTERCONNECTOR (NEW)
- PEAK DEMAND (CT)
- GB TO IOM

SOURCE: ARUP ANALYSIS

*Biomass could potentially be replaced with another carbon neutral biofuel

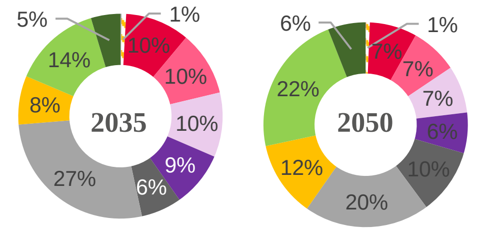
Summary of Key Findings

Installed Capacity(MW) and Generation(GWh): Scenario 4

S4

Scenario 4 has significantly higher proportion of on-island generation, and highest resilience (N-2) of all four scenarios. This scenario minimises imports, opening up export opportunities for IoM.

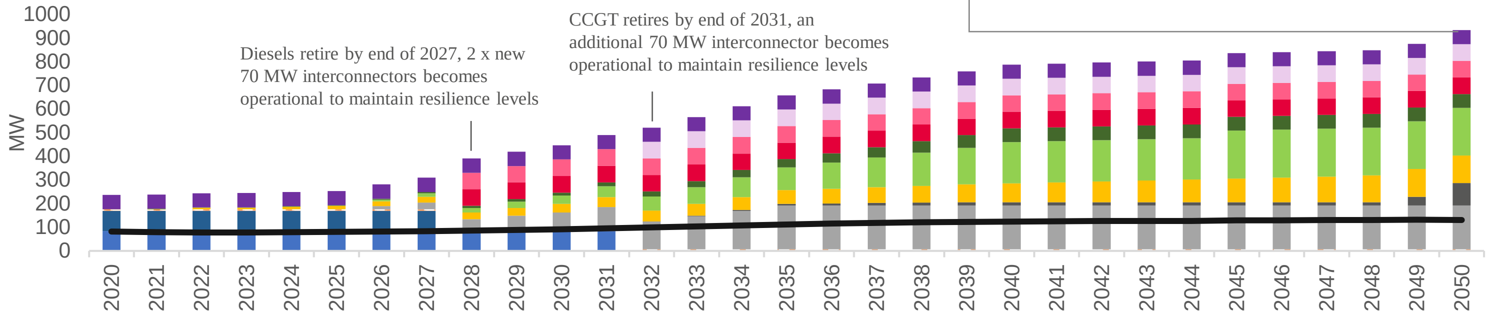
INSTALLED CAPACITY (MW)



Significant increase in pumped storage between 2049 and 2050 to provide dispatchability to meet increased demand.

Diesels retire by end of 2027, 2 x new 70 MW interconnectors becomes operational to maintain resilience levels

CCGT retires by end of 2031, an additional 70 MW interconnector becomes operational to maintain resilience levels



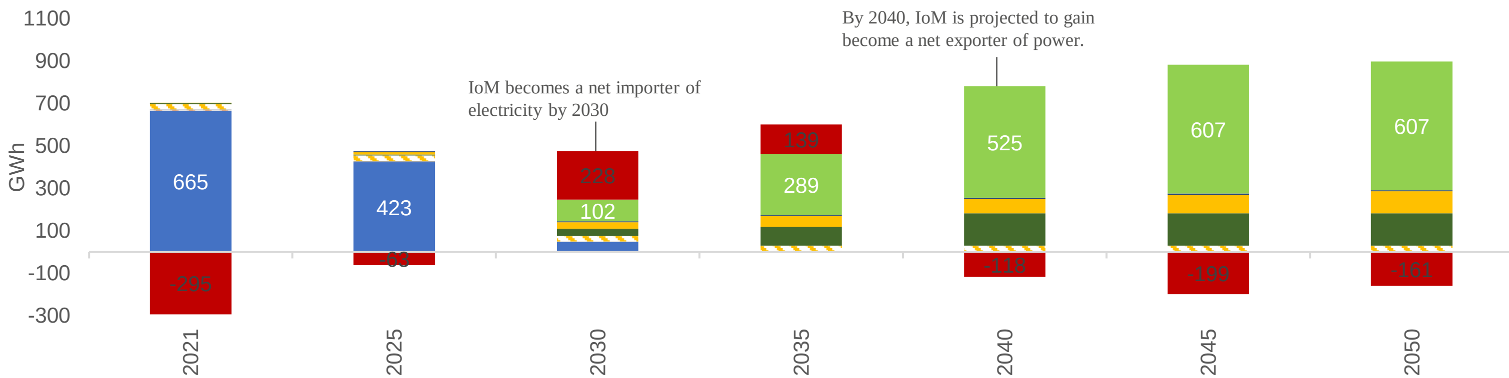
LEGEND

- CCGT
- DIESEL
- HYDROPOWER
- ENERGY FROM WASTE (EFW)
- ONSHORE WIND
- OFFSHORE WIND
- SOLAR (DISTRIBUTED)
- ENERGY STORAGE (BATTERY)
- *ENERGY STORAGE (PUMPED SEAWATER)
- INTERCONNECTOR (EXISTING)
- INTERCONNECTOR (NEW 1)
- INTERCONNECTOR (NEW 2)
- INTERCONNECTOR (NEW 3)
- PEAK DEMAND (CT)
- GB TO IOM

GENERATION (GWH)

By 2040, IoM is projected to gain become a net exporter of power.

IoM becomes a net importer of electricity by 2030



SOURCE: ARUP ANALYSIS

*The environmental impact associated with pumped seawater storage would need to be considered, given it may require roughly c.3 million m³ of storage – this equates to approximately 67% of the size of the Sulby reservoir. Further assessments are required to confirm the reservoir size and environmental impact.

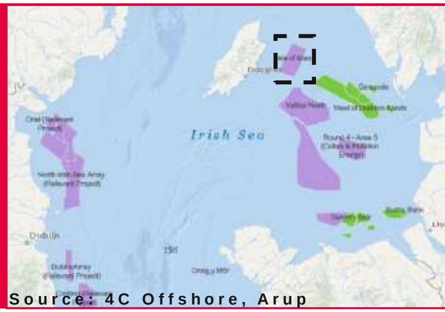
IoM is also exploring an additional Scenario 5 centred around a 700-800MW offshore wind farm in IoM territorial waters. Commercial challenges need addressing to assess the viability of this scenario.

Legend

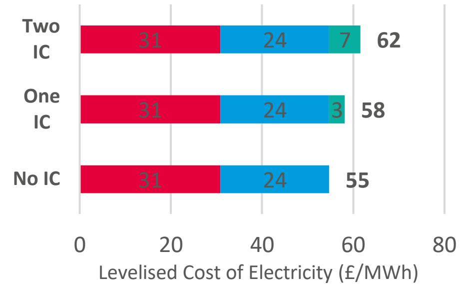
- CAPEX
- OPEX
- IC COSTS
- PROPOSED OFFSHORE DEVELOPMENT

Isle of Man

IoM Offshore Development Location



IoM LCoE Model Outputs

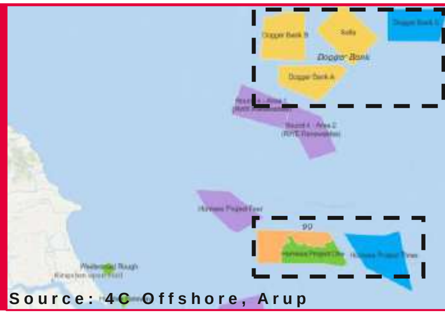


IoM Undiscounted Costs

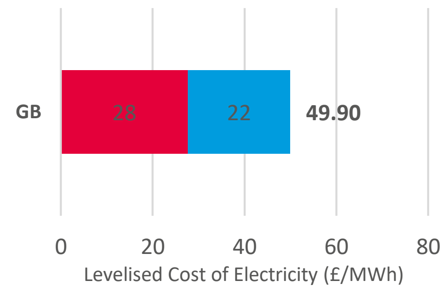
Scenario	Capex	Opex	IC Cost
IoM Two ICs	£1.46bn	£2.50bn	£0.38bn
IoM One IC	£1.46bn	£2.50bn	£0.19bn
IoM No IC	£1.46bn	£2.50bn	-

Great Britain

GB Offshore Development Location



GB LCoE Model Outputs

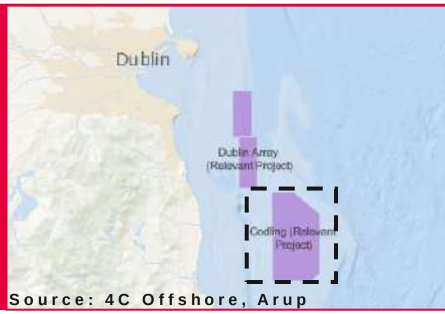


GB Undiscounted Costs

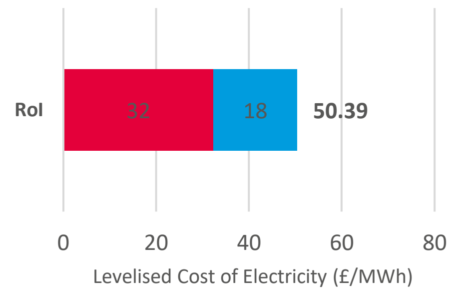
Scenario	Capex	Opex	IC Cost
GB	£1.42bn	£2.53bn	-

Republic of Ireland

RoI Offshore Development Locaiton



RoI LCoE Model Outputs



RoI Undiscounted Costs

Scenario	Capex	Opex	IC Cost
RoI	£1.74bn	£2.17bn	-

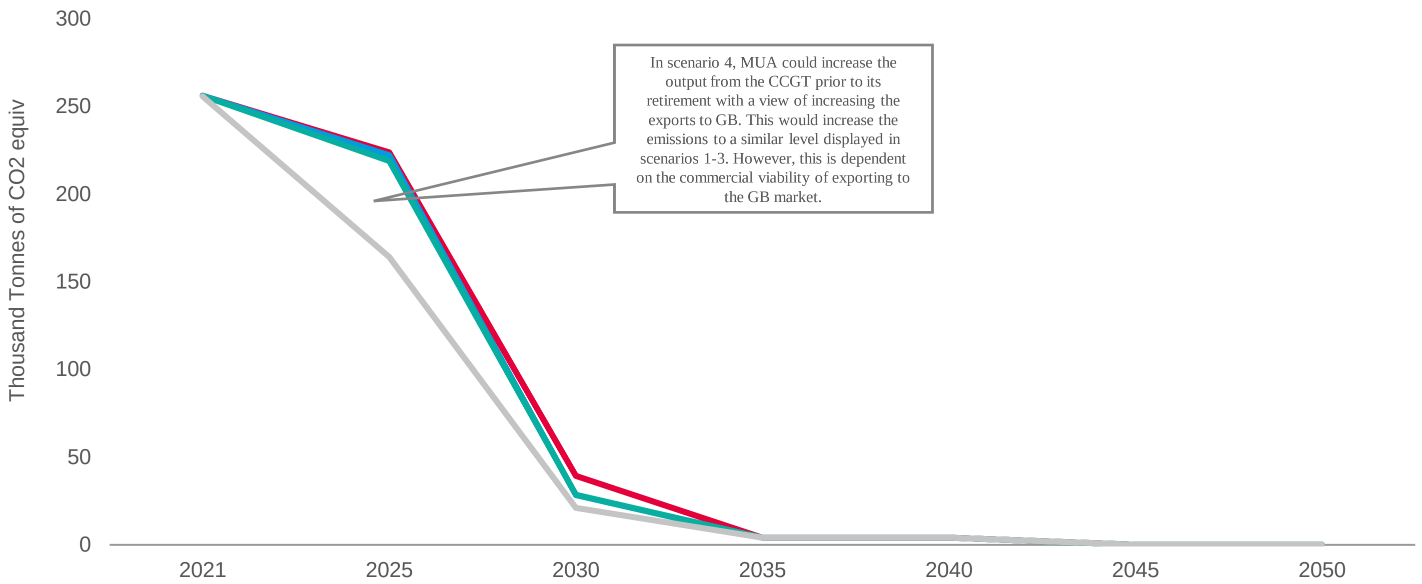
SOURCE: ARUP ANALYSIS; 4COFFSHORE; BEIS; EIRWIND

Carbon emissions decline significantly across all four scenarios. Emissions are projected to reduce ahead of schedule, driven by retirement of existing fossil fuel plants, increased renewable penetration and imports.

LEGEND

- Scenario 1
- Scenario 2
- Scenario 3
- Scenario 4

TOTAL CARBON EMISSIONS CO2, CH4 & N20 (THOUSAND TONNES OF CO2 EQUIV.)



CO2 Emissions (THOUSAND TONNES OF CO2 EQUIV)

		2021	2025	2030	2035	2040	2045	2050
S1	CO2	255	223	39	4	4	-	-
S2		255	222	28	4	4	-	-
S3		255	218	28	4	4	-	-
S4		255	163	21	4	4	-	-

SOURCE: ARUP ANALYSIS

- Across all four scenarios, the IoM reaches its net zero target by 2045.
- Vast majority of the emission reductions take place by 2035, driven mainly by the retirement of the existing diesel and CCGT power plants. These retirements trigger the introduction of intermittent renewables, including biomass, and interconnector(s) which increases imports.
- The faster-than-anticipated emissions reduction trajectory suggests that there may be a possibility to delay some investment decisions by delaying the retirement of the existing CCGT plant.
- However, this is subject to the quantity of hydrogen in the gas grid in the future, and the ability of the existing CCGT to accommodate hydrogen blended gas.

Overall, scenario 4 is estimated to be the most expensive due to it having the largest installed capacity, driven by the desire for maximum on-island generation and highest resilience.

NOTE

The annual opex, capex, fuel and network costs have been discounted to provide a comparison of the overall costs of each scenario in NPV terms.

Discount rate of 5% has been use as advised by IoM.

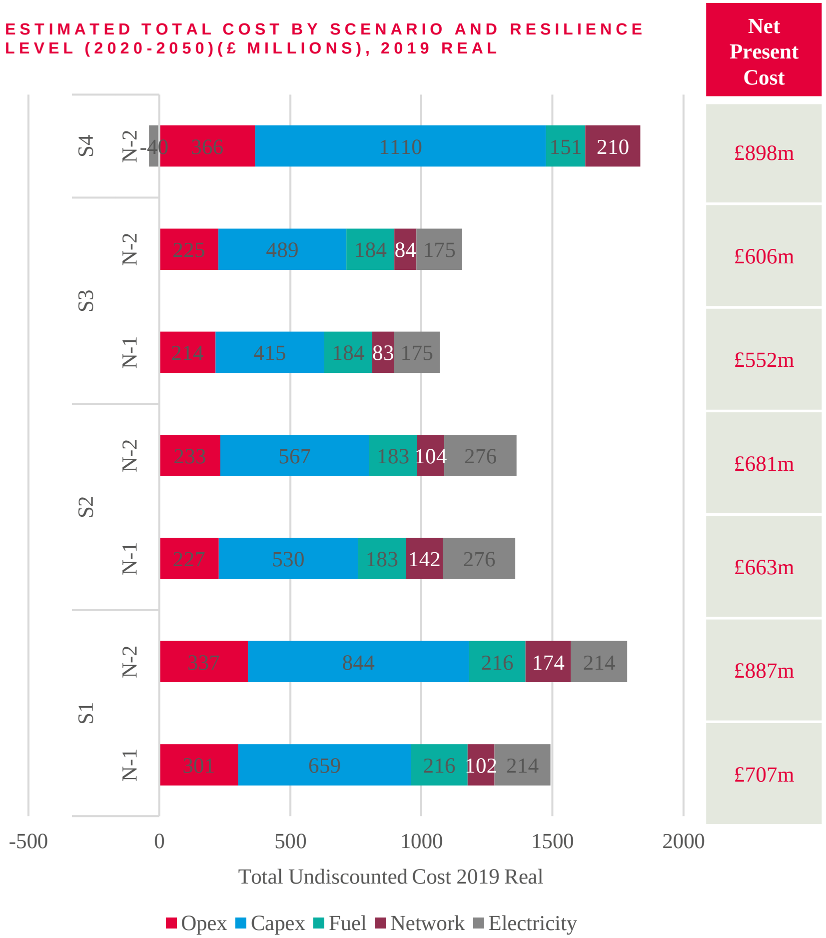
It is important to note this analysis is based on a high level indicative cost estimate to provide a cost comparison between scenarios.

KEY OBSERVATIONS

- The cost implications for a scenario are typically driven by the relationship between three key factors:
  - The level of resilience
  - The technology mix, including that required for resilience
  - The extent of on-island generation
- Scenario 4 has the maximum on-island generation. Consequently, it has the highest installed capacity across all scenarios, and is therefore estimated to be the most expensive.
- The higher the installed capacity, the more reinforcement is required on the network to accommodate the additional generating units.
- This further exacerbates the cost implications. As a consequence, the network implications cost are also estimated to be the highest for Scenario 4 compared to other scenarios.
- However, increasing on-island generation also minimises the need for importing energy from overseas markets (e.g., Great Britain). Consequently, the cost of importing energy is the lowest in Scenario 4.
- In summary, the benefits of increased on-island generation need to be weighed against the risk of importing power.
- Similarly, the benefits of increased resilience also need to be weighed against the potential risk and consequences of power outages.

Across scenario 1-3, the generation from biomass decreases over time as interconnector capacity increases. Subject to further analysis, there may be an opportunity to reduce overall costs across the four scenarios by brining forward the operation of new interconnectors. However, this will need to be weighed against potentially higher electricity import costs in earlier years.

ESTIMATED TOTAL COST BY SCENARIO AND RESILIENCE LEVEL (2020-2050)(£ MILLIONS), 2019 REAL



***The electricity costs shown on the chart above are the net costs after accounting for both the estimated import and estimated export.**

SOURCE: ARUP ANALYSIS

On a p/kWh basis, Scenario 4 is also estimated to be the most expensive.

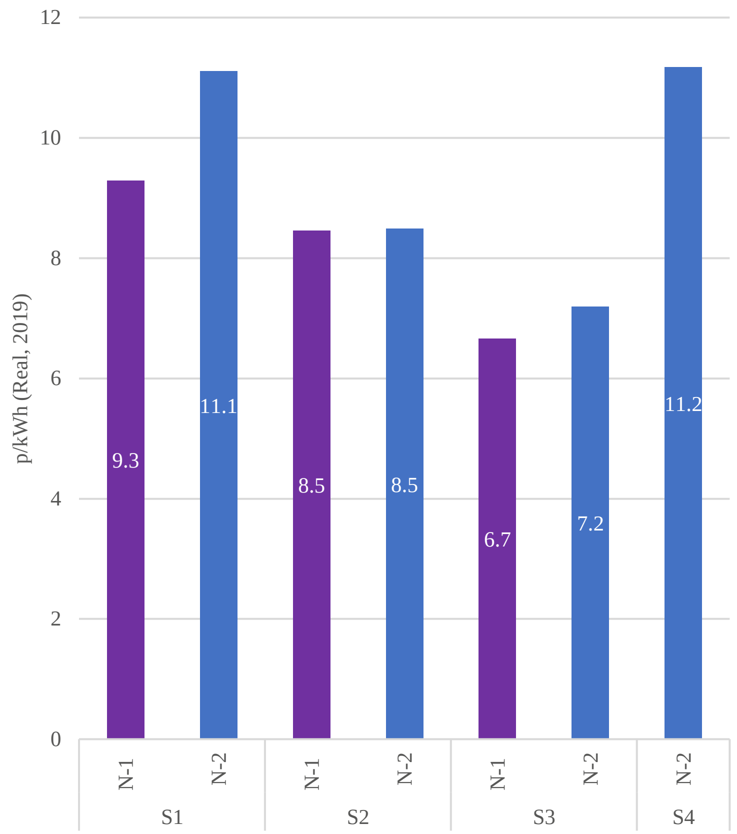
ASSUMPTIONS

- **Calculation methodology:** The estimated cost in p/kWh has been calculated by dividing the sum of the annual costs by the sum of the annual demand over the transition period from 2020-2050.
- The estimated annual demand is based on the consumer transformation scenario.
- The estimated annual costs, annual demand and the resulting cost in p/kWh presented on this page have not been discounted.

KEY POINTS:

- The estimated costs in p/kWh presented on this page for various scenarios are not consumer tariffs, i.e. these are not retail prices. Hence, these estimates do not reflect what consumers on the IoM will pay for the electricity in the future.
- It is likely that the retail price paid by end consumers will be higher. This is because the retail price is expected to include other items such as operational costs for MUA, potential taxes and levies and supplier margins.
- Additionally, the wholesale price estimates developed for these scenarios may also evolve over the long term with evolving supply and demand dynamics across the whole of north west Europe, and its interconnection with the GB market.
- Whilst this analysis gives a relative comparison of the costs of individual scenarios, the impact on end consumer price will depend on how the Isle of Man choses to fund and finance the transition over the long term.
- The IoM have estimated the cost for MUA at 5.4p/kWh, however Arup have not reviewed this calculation or validated this figure.

TOTAL ESTIMATED UNDISCOUNTED SCENARIO COSTS, P/KWH (REAL, 2019)



SOURCE: ARUP ANALYSIS

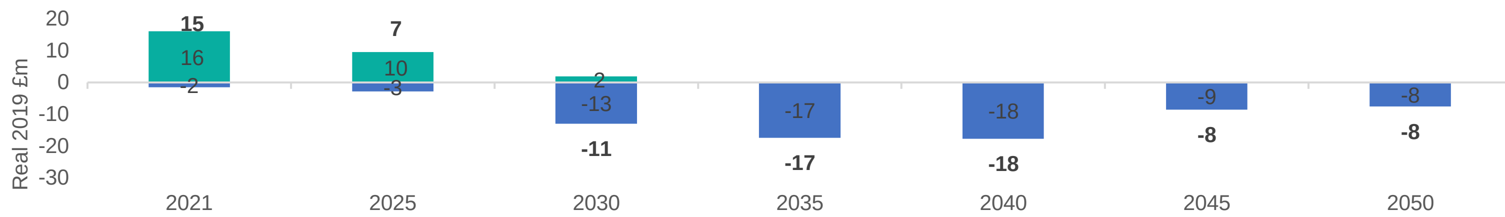
Electricity export revenue and import cost comparison

There is little difference in the export revenue/import costs across Scenarios 1-3. Scenario 4 has comparatively less imports and shows the potential for net exports, albeit a small amount, by 2050.

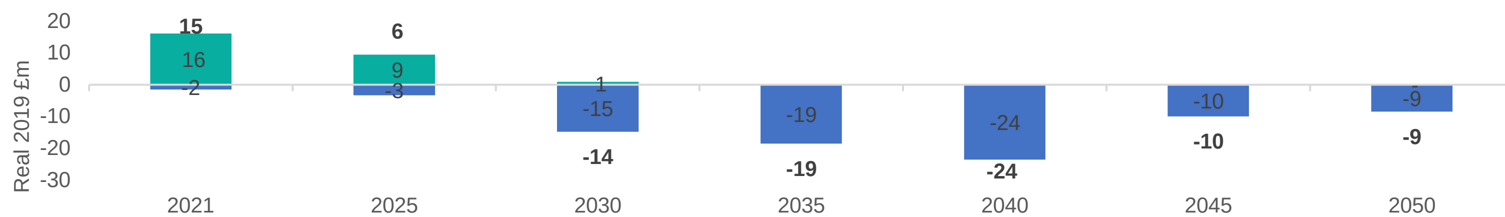
LEGEND

- EXPORT REVENUE
- IMPORT COST

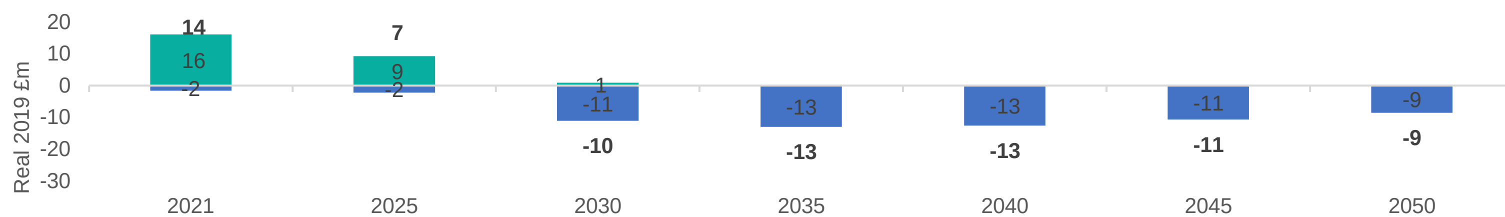
SCEANRIO 1 REVENUE / COST (REAL 2019 £M)



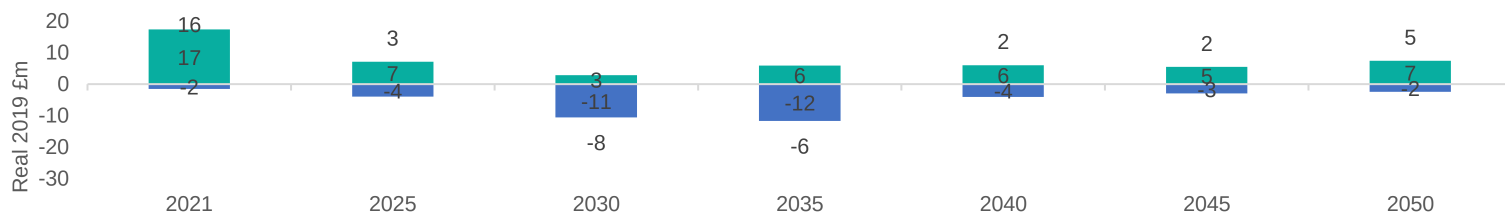
SCEANRIO 2 REVENUE / COST (REAL 2019 £M)



SCEANRIO 3 REVENUE / COST (REAL 2019 £M)



SCEANRIO 4 REVENUE / COST (REAL 2019 £M)



SOURCE: ARUP ANALYSIS

Arup has identified seven key recommendations to inform the transition of the island's electricity network, and to support decision making over the longer term (1 of 2)

1 Assess future system resilience requirements

- The resilience level required for the future electricity system needs to be reviewed and agreed, as it has significant impacts on the amount and type of installed electricity generation capacity required in the future.

2 Identify suitable pool of technologies required to meet future resilience

- Based on current discussions with the IoM Climate Change Transformation Team, it is understood that the island will need to have a dispatchable and carbon neutral electricity source to provide the necessary level of resilience by 2050.
- For the purpose of this study and as agreed with the IoM team, biomass and interconnectors have been implemented in the model as the most suitable dispatchable and carbon neutral sources. However, biodiesel, biogas or other suitable biomaterial can be considered as alternatives.
- When making this decision the feasibility of each option needs to be carefully assessed, such as understanding on island fuel availability, import rules and infrastructure requirements such as fuel processing facilities, transportation and storage.
- For biogas, as an example, farming subsides may need to be introduced so farmers grow the crop, large areas of land will need to be identified for this purpose and anaerobic digestion plants will need to be built, as well as gas storage and transport systems.

3 Undertake detailed interconnector feasibility study

- Based on the outcome of this study and discussions with IoM, adding more interconnection is a no-regret/low-regret solution.
- It will give the IoM greater resilience capacity, and is a compatible solution with any further generation installations that may take place on the IoM.
- It also provides greater long-term flexibility in deciding between on-island generation vs import of electricity.
- IoM should perform a full feasibility study and cost benefit analysis to decide on type and size of interconnection that should be pursued.
- IoM should also engage with relevant parties (e.g., National Grid) to inform the procurement of a new interconnector.

SOURCE: ARUP ANALYSIS

Arup has identified seven key recommendations to inform the transition of the island's electricity network, and to support decision making over the longer term (2 of 2)

4 Finalise waste strategy

- The Island's waste strategy needs to be developed. It has implication for future waste volumes accessible to the EfW.
- Arup's understanding is that the island's waste management strategy is striving for a reduction in waste volumes – this is consistent with the general trends and policy direction across the UK and Europe. We therefore envisage EfW generation to decline in the future.
- If the EfW generation capacity is maintained at its current level, or increased, in the future, then this may help with some reduction in other on-island renewable generation. However, the reduction is envisaged to be minimal, given the EfW is a small 5MW plant, operating at c.60% capacity.
- Additionally, it allows certain investment decisions to be delayed. However, this is dependent on the future waste volumes and the associated biogenic content.

5 Finalise heating strategy

- The heating strategy will have significant impacts on the island's electricity demand, which will ultimately impact amount of generation capacity required in the future. Therefore, finalising this strategy is a key step before other non-interconnector technology development on the island is considered.
- The IoM should also evaluate during this process whether there are any potential synergies with future the electricity generation that can be leveraged or any foreseen issues between heating and electricity supply (e.g biomass fuel constraints).

6 Finalise transport strategy

- The evolution of transport on the IoM is a key driver of demand and therefore the level of future generation required. The transport strategy needs to be finalised to inform the evolution of the electricity demand. This strategy also needs to address requirements, if any, for phasing out of ICE (petrol and diesel) vehicles and incentives required to support the up-take of EVs. Additionally, it needs to present pathways for alternative fuels for public transport and larger vehicles.

7 Introduce policy changes

- A number of policy drivers including clean air act, carbon tax, incentives for energy efficiency and uptake of alternative fuel vehicles need to be developed to enable the transition.

SOURCE: ARUP ANALYSIS

2. CONTEXT

The global climate crisis has continued to escalate, driven mainly by increasing greenhouse gas emissions and rising global temperatures.

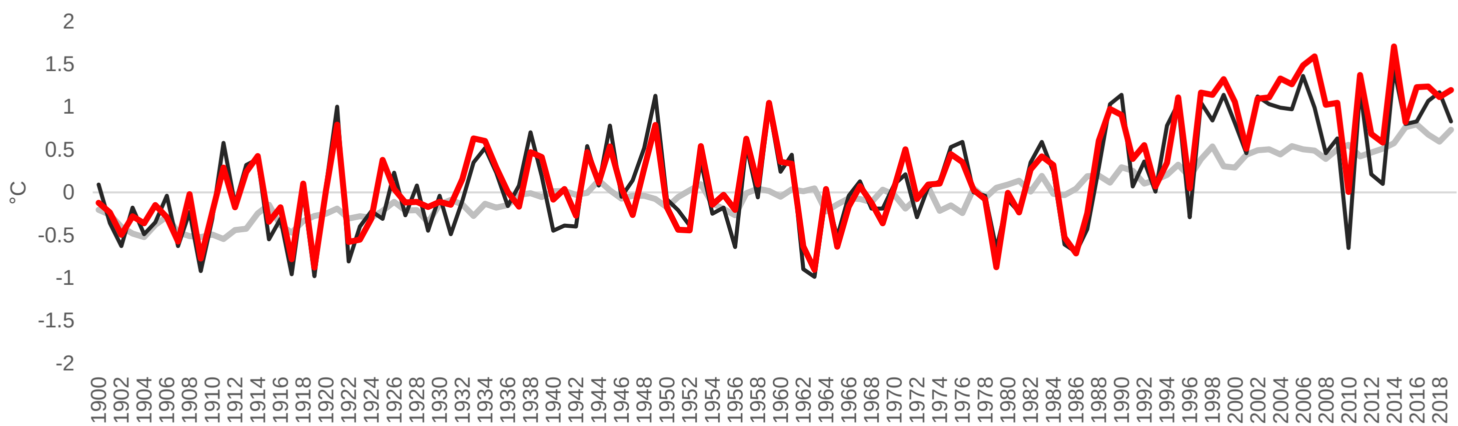
LEGEND

- Global Temperature Anomaly
- UK Temperature Anomaly
- IoM Temperature Anomaly
- Global Carbon Dioxide Emissions from Coal
- Global Carbon Dioxide Emissions from Oil
- Global Carbon Dioxide Emissions from Gas
- Global Carbon Dioxide Emissions from Other Sources†

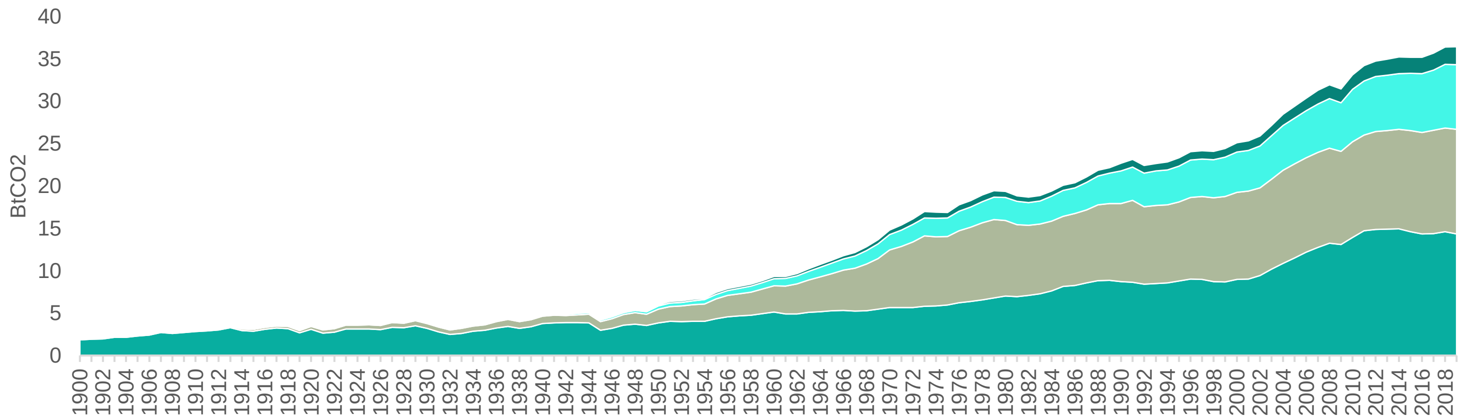
† Other Sources: Flaring, Cement & Industry

* Met Office Hadley Centre for Climate Change

GLOBAL, UK AND THE ISLE OF MAN TEMPERATURE ANOMALY: 1900-2019 (°C), BASE 1961-1990



GLOBAL CO2 EMISSIONS BY FUEL TYPE: 1900-2019 (MtCO2)



SOURCES: GLOBAL CARBON PROJECT & CARBON DIOXIDE INFORMATION ANALYSIS CENTRE, 2020; MET OFFICE, (2020)*

Paris Climate Agreement

Whilst nations across the globe are united in their recognition of the challenge, an effective consensus-based response to the crisis has been difficult to agree and implement.

KEY DRIVERS

DIFFERENTIATION	• Developed countries must continue to 'take the lead' in the reduction of emissions. • Developing nations are encouraged to 'enhance their efforts'.
FINANCE	• Rich countries have set a collective goal of providing $ 100 billion from 2020 as a 'minimum floor'. • Amount to be updated by 2025.
REVIEW MECHANISMS	• 2020 was the deadline for countries to submit their plans for climate action known as nationally determined contributions (NDCs). • These NDCs will be reviewed every five years, starting in 2023.

LEGEND

- Ratified
- Signed
- Newly re-joined*

LOOKAHEAD

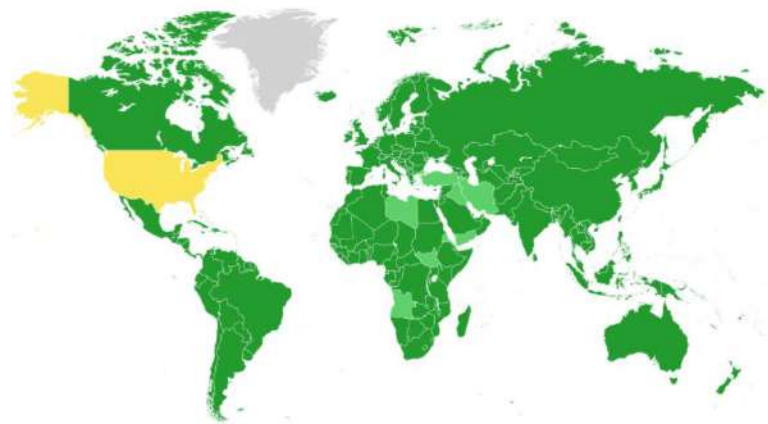
Some setbacks along the way
'*Global carbon emissions are set to rise this year despite mounting international pressure to reverse a trend that pushes the world further from the goals of the Paris climate accord*'
Financial Times, December 2019

But progress is being made
'According to the International Energy, by 2025, renewable energy will be the biggest source of power, displacing coal.'
The Guardian, December 2020

*Donald Trump withdrew the US in 2017; however, on January 20, 2021 President Biden re-entered the agreement effective from February 19, 2021

PARIS AGREEMENT AND PARTICIPATING COUNTRIES, 20 JANUARY 2021

- Sets a long-term goal to limit the increase in global average temperature 2˚C, and pursue efforts to limit the increase to 1.5˚C.
- These temperature goals were set to reduce the risks and impacts of climate change driven by carbon emissions.
- Signed in 2016, with 197 countries now having endorsed the agreement. Of those, 10 countries have solidified their support with formal approval.



SOURCES:RESEARCHGATE, ABC ACTION NEWS; THE GUARDIAN (2020); BUSINESS INSIDER (2017); UNITED NATIONS CLIMATE CHANGE (2019); STATISTA (2021), NRDC

GHG emission on the IoM have remained largely stable over the past few years. The electricity sector accounts for about 22% of the island's emissions, majority of these come from the CCGT plant.

TOTAL EMISSIONS LEGEND

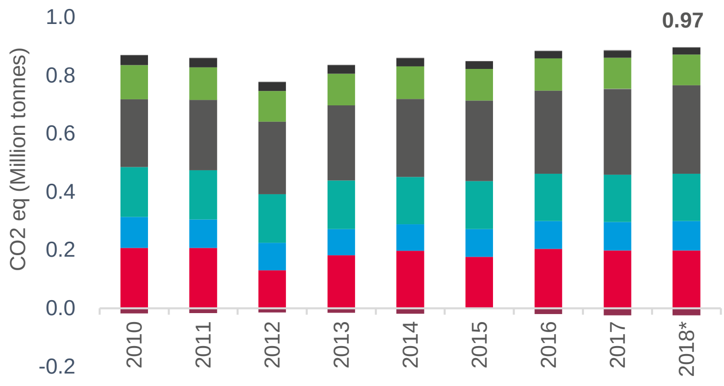
- LAND USE CHANGE
- WASTE MANAGEMENT
- AGRICULTURE
- RESIDENTIAL
- TRANSPORT
- BUSINESS
- ELECTRICITY GENERATION

ELECTRICITY GENERATION LEGEND

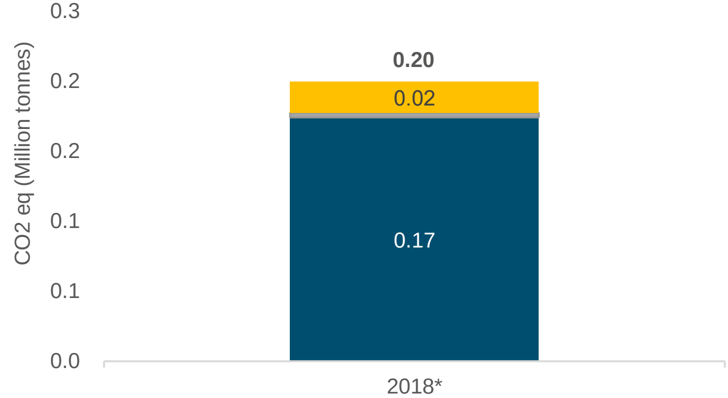
- ENERGY FROM WASTE (EFW)
- DIESEL
- CCGT

*2018 electricity generation emissions data is the only data point which has been corrected by the IoM Government / Aether, all other data is currently being recalculated.

TOTAL EMISSIONS (CO2 EQ. MILLION TONNES)



EMISSIONS FROM ELECTRICITY GENERATION IN 2018 (CO2 EQ. MILLION TONNES)



SOURCE: MANX UTILITIES, AETHER, THE IOM GOVERNMENT CLIMATE CHANGE TRANSFORMATION TEAM

- The emissions data presented is currently in the process of being recalculated and refined by the Isle of Man Government and Aether. It is understood that there may be some overestimation of the emissions on the island; however, the recalculated emissions data is expected to remain broadly the same.
- The largest sectors for GHG emissions are the residential, transport and electricity generation sectors, contributing to c. 76% of total emissions.
- Within the electricity generation sector, as of 2018, the Combined Cycle Gas Turbines (CCGT) plant is responsible for 87% of emissions, while the Energy from Waste (EfW) plant and diesel generators account for 11% and 2% respectively.

Climate action of the IoM: Timeline of progress and key consideration

The IoM has recently made important strides in its response to the climate emergency. A Climate Change Bill was introduced in 2019, committing to Net Zero carbon equivalent emissions by 2050.

*this team now is called the Climate Change Transformation Team

TIMELINE OF RECENT CLIMATE CHANGE POLICY PROGRESS

2019

May 2019- Chief Minister announced intention to bring forward a Climate Change Bill to commit the current and future governments to a target of Net Zero greenhouse gas emissions by 2050 *(revised bill introduced in November).*

June 2019- Tynwald committed unanimous support, with council of ministers tasked to set up a dedicated Climate Emergency Transformation Team*.

July 2019- Professor James Curran appointed as the Independent Chair of the Climate Emergency Transformation Consultative Team.

October 2019- James Curran's IMPACT report submitted to the Isle of Man Government.

2020

January 2020- The council of ministers present the Phase 1 action plan as part of the Isle of Man Government Action Plan for Achieving Net Zero greenhouse gas emissions by 2050. 10 points for immediate implementation identified for the following 12 months (outlined on following slide).

December 2020- Arup appointed to develop future energy scenarios (FES) for the evolution of the IoM's *electricity system* in light of its climate targets and other island-specific ambitions.

2021

KEY CONSIDERATIONS

- It is important to note that whilst this report is largely focused to the IoM's electricity system, the recent policy commitments to Net Zero emissions by 2050 are related to emissions from all sectors and not just electricity generation. In addition, the climate action on the island is wider reaching than just emissions reduction and aims to promote sustainability across the island.
- While the transition to Net Zero is seen as a must, it is important that the island leads a fair transition. Proposed actions need to be fully cognisant of not just the reduction in emissions, but also need to ensure that nobody is left behind.
- The energy trilemma must be at the forefront of decision-making ensuring solutions for achieving Net Zero emissions consider environmental, economic and security of supply considerations.
- The Isle of Man is proud of its UNESCO Biosphere status and aims to maintain this. Therefore, aligning with UNESCO sustainability principles is also key during this transition.
- Ensuring the pathway to achieving Net Zero emissions by 2050 takes a n regret approach is essential. Flexibility is essential to ensure that new technologies can be incorporated and utilised if and when they become available.
- In addition to the target of Net Zero emissions by 2050 and the above considerations, the government is working towards intermediary climate targets specifically related to the electricity system (which are key drivers of this study):
  - Installation of 20 MW of generation capacity from renewable sources by 2025. (Note this is an ambition and not a target determined by the Climate Change Bill).
  - 75% of electricity generation to come from renewable or carbon neutral technology by 2035.

SOURCE: ISLE OF MAN GOVERNMENT ACTION PLAN FOR ACHIEVING NET ZERO EMISSION PHASE 1 AND CLIMATE CHANGE TRANSFORMATION TEAM

The Isle of Man Government has set out a 10-point action plan aimed at supporting the island's transition to net zero emissions by 2050. This includes increasing renewable energy penetration.

1. Climate Change Transformation Programme

- Establishment of dedicated fund in 2020 / 2021 to support transformation activities
- Creating a transformation programme structure and team

2. Government-led Initiatives

- Commitment and visibility through Government leading the way
- Decarbonisation of Government's fleet of vehicles
- Accelerated installation of EV charging points
- Retro-fitting public buildings for improved energy efficiency

3. Increased Renewable Energy Penetration

- Commitment to secure no less than 75% of Isle of Man's electricity from renewable sources by 2035

4. Financial and Non-financial Initiatives

- Recognition of the need for wide ranging financial and non-financial initiatives
- Acknowledging the need for a diverse energy mix
- Decarbonisation of residential heating (potential ban on fossil fuel based heating in new development by 2025)
- Introduction of alternatives such as hydrogen

5. Carbon Capture and Storage

- Development of land and sea management plans
- Identify opportunities for carbon capture and storage (woodlands, peatlands, marine ecosystems)

6. Decarbonisation Transport by 2050

- Emissions from transport sector to be reduced to net zero by 2050.
- Introduction of active-travel initiatives
- All-island charging network by 2030

7. Engagement with business and industries

- Improve understanding of emissions associated with business and industry
- Encourage green growth and innovation

8. Climate Change Bill

- Commitment underpinned by Climate Change Bill
- Revised bill introduced in November 2020

9. Awareness and engagement campaign

- Campaigns to highlight the role of consumer and individuals in achieving emissions neutrality

10. Further research and analysis

- Development of potential pathways and actions
- Financial analysis to support prioritisation of action

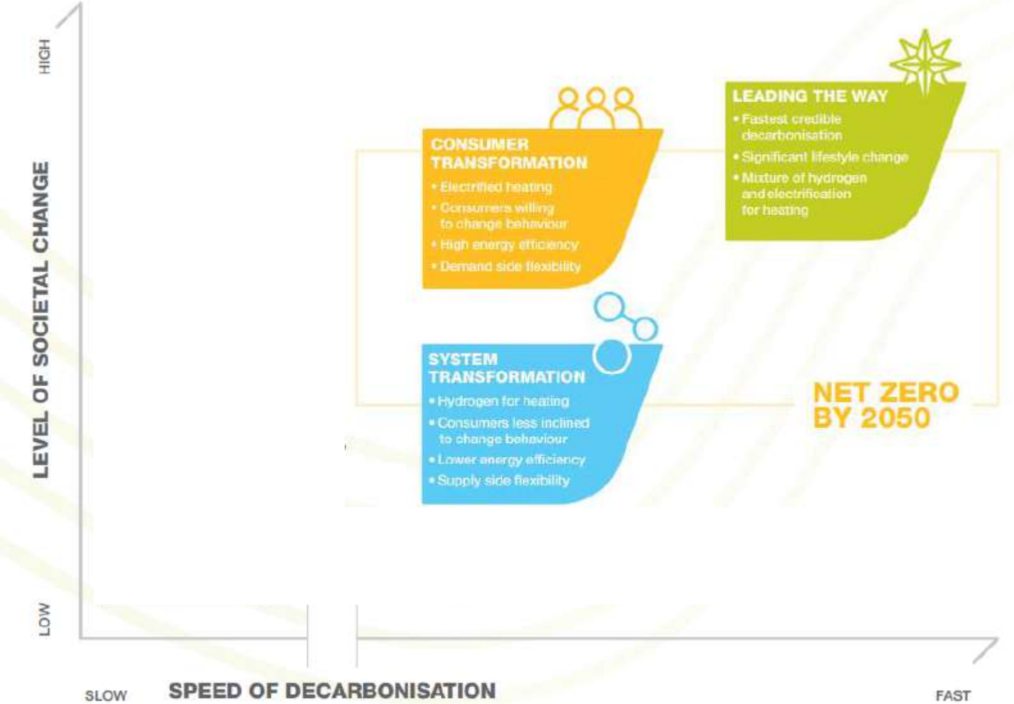
SOURCE: ISLE OF MAN (IOM) GOVERNMENT'S 10-POINT ACTION PLAN FOR NET ZERO EMISSIONS BY 2050

IoM's transition to net zero has implications for the electricity sector. To support the island's transition, Arup has developed three scenarios to assess the evolution of electricity demand and generation on the island.

NATIONAL GRID FUTURE ENERGY SCENARIOS

- The National Grid (the UK electricity transmission system operator) annually publish a set of scenarios on how the UK's energy system could evolve out to 2050, called the Future Energy Scenarios (FES).
- These scenarios include how the electricity system could evolve in terms of generating technologies and demand.
- The National Grid FES factors in the latest view of technological and consumer trends to provide the most current understanding of the electricity system evolution to 2050.
- Four scenarios were published in the latest 2020 FES. Three of these scenarios deliver net-zero by 2050, and are therefore aligned to the government climate targets on the IoM for the electricity system. These scenarios have been used as a guide for driving the evolution of electricity demand on the IoM.
- Arup, in collaboration with the IoM government, has developed a detailed bottom-up assessment of the evolution of electricity demand on the island under different scenarios. This approach acknowledges the key differences between the IoM and the UK, and allows for a island-specific assessment.

FES OUTCOMES



SOURCE: NATIONAL GRID FUTURE ENERGY SCENARIO 2020

KEY CONSIDERATIONS FOR IOM

1. To what extent and at what speed will electrification of heat take place?
2. What levels of energy efficiency will be achieved?
3. What role will electricity play in the decarbonisation of transport?
4. What generating technologies will be needed to match future demand?
5. What capacity of storage will be chosen?

3. ELECTRICITY DEMAND

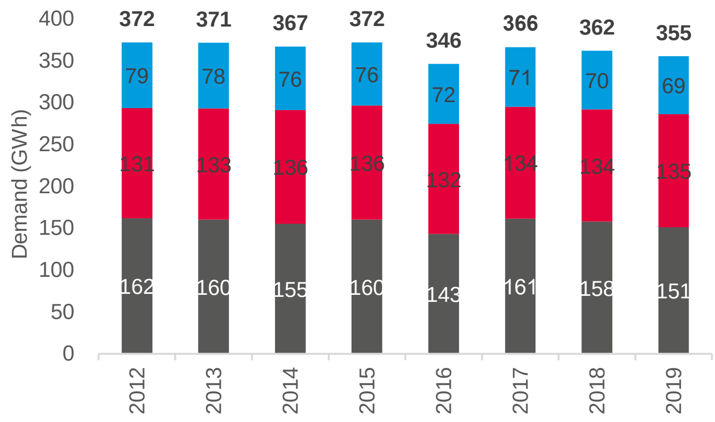
The electricity demand on the Isle of Man has gradually declined since 2012. This trend is most likely driven by increasing energy efficiency gains.

LEGEND

- Residential Demand
- Industrial Demand
- Commercial Demand

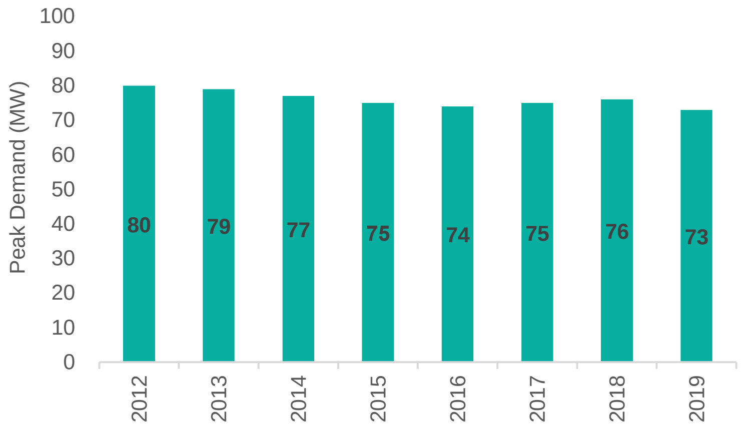
***Note**: Historical electricity demand presented here does not include transmission & distribution losses

HISTORICAL ANNUAL ELECTRICITY DEMAND BY SECTOR (2012A-2019A)*



SOURCE: MANX UTILITIES AUTHORITY (MUA)

HISTORICAL PEAK ELECTRICITY DEAMND (2012A-2019A)*



SOURCE: MANX UTILITIES AUTHORITY (MUA)

Annual Demand (GWh)

- The annual electricity demand on the Isle of Man has gradually declined since 2012. Between 2012 and 2019, annual demand decreased by 17 GWh, or approximately 5%.
- The drop in annual electricity demand has been driven by decreases in residential and commercial demand; however, industrial demand has increased.
- Residential demand has dropped from 163 GWh to 151 GWh, which equate to a reduction of -12 GWh approximately 7%. The reason for the decline over the last seven years is most likely attributed to appliance and lighting efficiency gains.
- Electricity demand from the commercial sector has declined by approximately 13% between 2012 to 2019, dropping from 79 GWh in 2012 to 69 GWh in 2019. Electricity demand from the industrial demand has seen a moderate increase of 4 GWh or 3%, since 2012. These trends are most likely linked to energy efficiency improvements and historical changes in the tariff structures, meaning some customers have reallocated themselves to take advantage of cheaper tariffs. For instance, some data centres have switched from commercial to industrial tariffs structure following the recent introduction of the cheaper high load factor tariff.

Peak Demand (MW)

- Peak demand has decline by 7MW from 2012 to 2019 or approximately 9%. The historical reduction in peak demand since 2012 is thought to be directly related to reductions in annual demand.

Electricity demand calculation methodology

Arup has developed a detailed bottom-up calculation methodology to assess the future evolution of electricity demand on the island from three key customer segments.

DEFINITIONS

Annual demand: Annual demand is the quantity of electricity consumed by customers on the Isle of Man. This unit is measured in Mega-Watt Hours (MWh) or Giga-Watt hours (GWh)

Electrical losses: This is electricity generated, but not consumed. Losses occur at multiple locations in an electrical system when distributing electricity from generation sources to consumers.

HIGH LEVEL OVERVIEW OF DEMAND VOLUME WORKFLOW

Electricity customer type → Historical building blocks → Forecasting assumption/input parameters → Scenario sensitivities → Electricity demand forecasts

Electricity customer type

Customers split into three categories:

1. Residential
2. Industrial/ Commercial
3. Transport

Electrical losses of 12% have been accounted for.

Historical building blocks

Collate the building blocks which characterise the three main customer segments and how electricity consumption for these individual segments has evolved historically.

Forecasting assumption/input parameters

Collate assumptions and inputs which can be used to characterise how this historical demand could evolve in the future

Scenario sensitivities

Adjust specific assumptions and inputs to generate alternating scenarios

Electricity demand forecasts

SOURCE: ARUP ANALYSIS

Arup has produced three scenarios for the evolution of electricity demand on the Isle of Man. These scenarios vary depending on the energy efficiency gains, electrification of heat and transport.

LEGEND

Scenario sensitivities

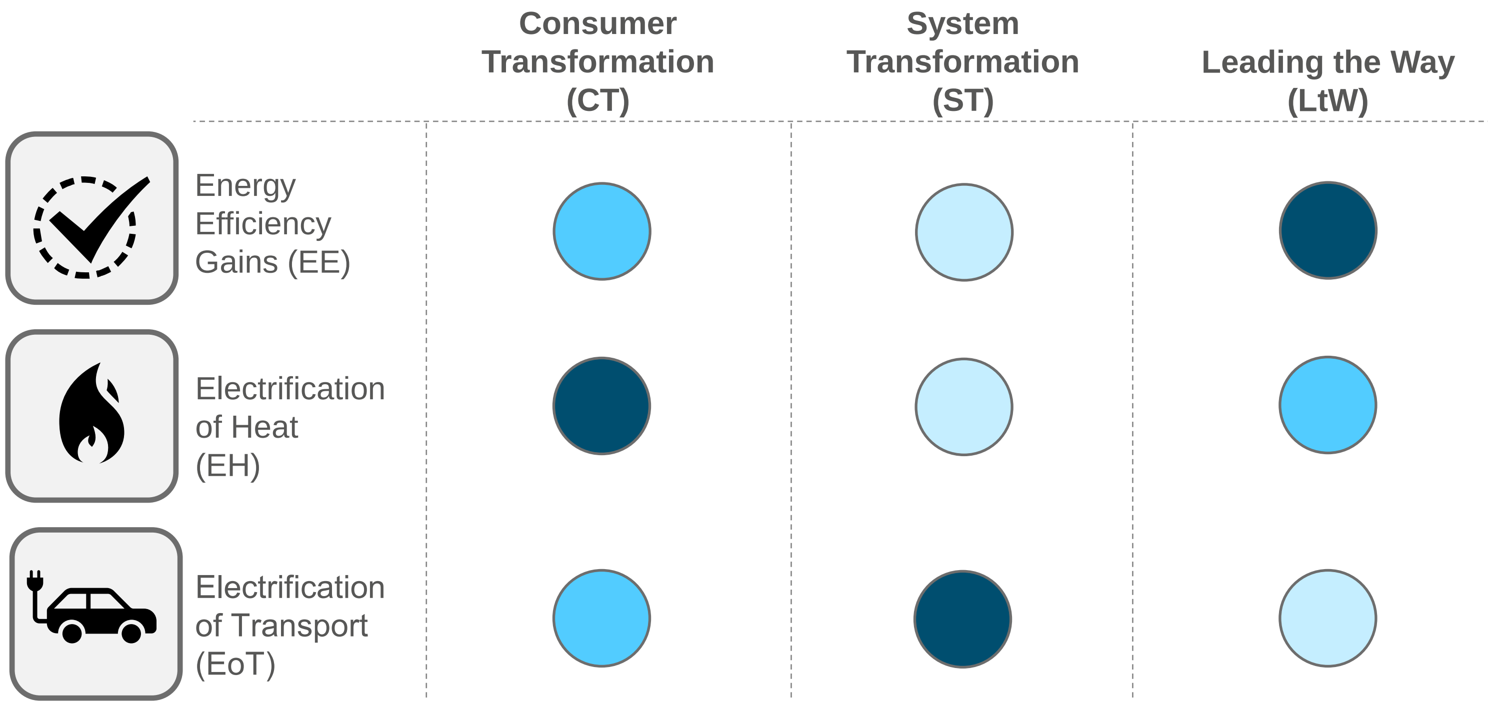
Total electricity demand

High

Medium

Low

Note- high, medium and low is relative to each other



ARUP

Electricity Demand

Residential demand: Forecasting methodology

Residential demand has been segmented into new and existing customers. These two sub-groups have been modelled separately, with their own assumptions and sensitivities.

DEFINITIONS

Existing Customers: customers as of the 2019/2020 billing data

New Customers: Potential future customers who join the electricity network from 2020/21 onwards.

*Energy efficiencies have focused on appliance improvements rather than buildings, this is to stay consistent with the absence of building efficiency incentives on the IoM

**Assumption supported by the government recently legislating to ban installation of gas boilers in new homes from 2025

Customer type	Historical building blocks		Forecasting assumption/input parameters			Scenario sensitivities	Forecasts
Existing customers	Non-electric heating customers	Demand per customer	Electrification of heating	*Energy efficiency (EE)		Energy efficiency; Electric heating penetration for existing customers	
	Electric heating customers	Demand per customer					
Comments	Existing customers split into two categories (electric heating and non-electric heating) using MUA data.		Electrification of heat assumptions overlaid to existing non-electric heating customers. Energy efficiency assumptions applied to both customer types.				
New customers	Historical relationship between population and residential customers	Demand per customer	All new residential customers use electric heating**	Pop. Growth Forecast	*Energy efficiency (EE)	Energy efficiency	
Comments	Historical relationship between population and residential customers chosen as basis to project future customers.		Population growth forecasts used to project new customer numbers out to 2050. Energy efficiency assumptions for new customer applied.				

SOURCE: ARUP ANALYSIS

Residential demand: Existing customers assumptions and scenarios

Energy efficiency gains are applied to all existing customers. Whilst all properties have the potential to have electric heating, the proportion of assumed electric heating varies by scenario.

LEGEND

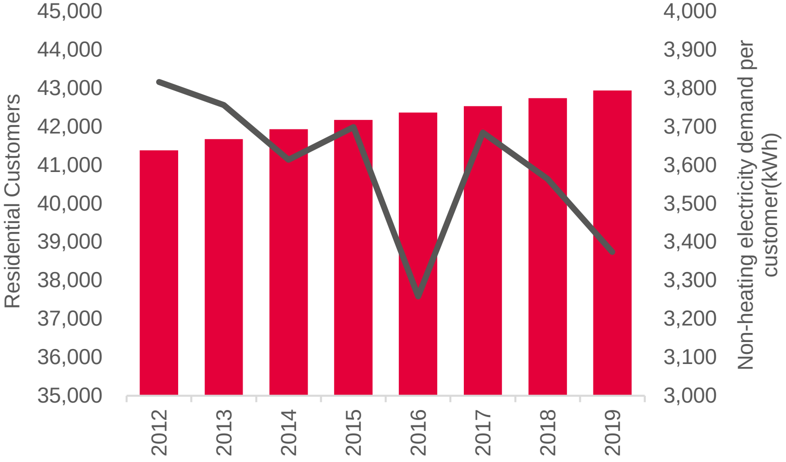
- Residential customers
- Non-heat electricity demand per customer

EXISTING CUSTOMER MODEL ASSUMPTIONS AND SCENARIOS

Assumptions

- Existing customer numbers (i.e. customers from the 2019/2020 billing data) remain the same – **there is no loss of customers**.
- The starting point for electricity demand per customer is derived from billing data provided by Manx Utilities. The non-heating electricity demand (appliance demand) was 3,374 kWh per annum in 2019/2020.
- Energy efficiency gains are derived from data from the FES 2020 scenarios.
- **All customers** will see gains in **energy efficiency** over time; however, energy efficiency gains are **only applied to non-heating demand.**
- Energy efficiency gains were only applied to non-heating demand due to lack of historical data or incentive mechanisms to support home heating efficiency improvements.
- Existing customers who currently use electric heating are assumed to **stay electrified**. Electric heating customers use **3,198 kWh** per year for heating requirements using heat pumps, calculated from MUA billing data.
- Existing customers who currently use non-electric forms of heating are assumed to convert to electric heating at the **same rate and percentage** as the FES scenarios, regardless of current heating solution. In all scenarios the existing customers being electrified does not reach 100%. Those not converting to electric heating are assumed to use an alternative heating solution.
- Electricity demand from electric vehicles is excluded from residential demand and is considered separately.

HISTORICAL CUSTOMERS AND NON-HEATING ELECTRICITY DEMAND PER CUSTOMER (2012A-2019A)



SOURCE: ANONYMISED MUA BILLING DATA

Residential demand: *Projected demand from existing customers*

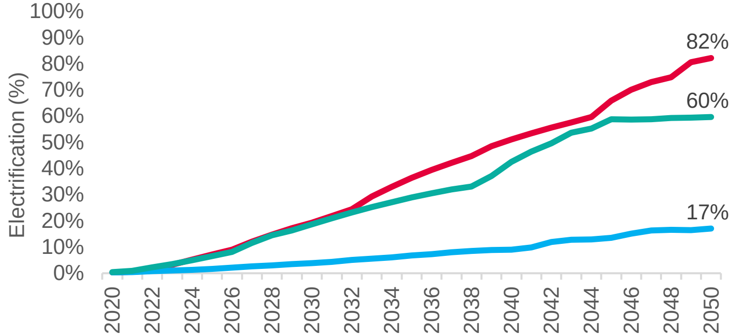
In all scenarios, residential demand from existing customers decreases in the short term due to efficiency gains. The CT scenario shows the highest increase in long term demand due to electrification of heating.

LEGEND

- Consumer Transformation (CT)
- System Transformation (ST)
- Leading the Way (LtW)

***Note**: Electricity demand does not include transmission & distribution losses

ELECTRIFICATION OF HEAT FOR EXISTING RESIDENTIAL PROPERTIES (2020F-2050F)



- The greatest number of properties have their heating electrified under the CT scenario, with the lowest under the ST scenario as alternative decarbonised heating measures are pursued.

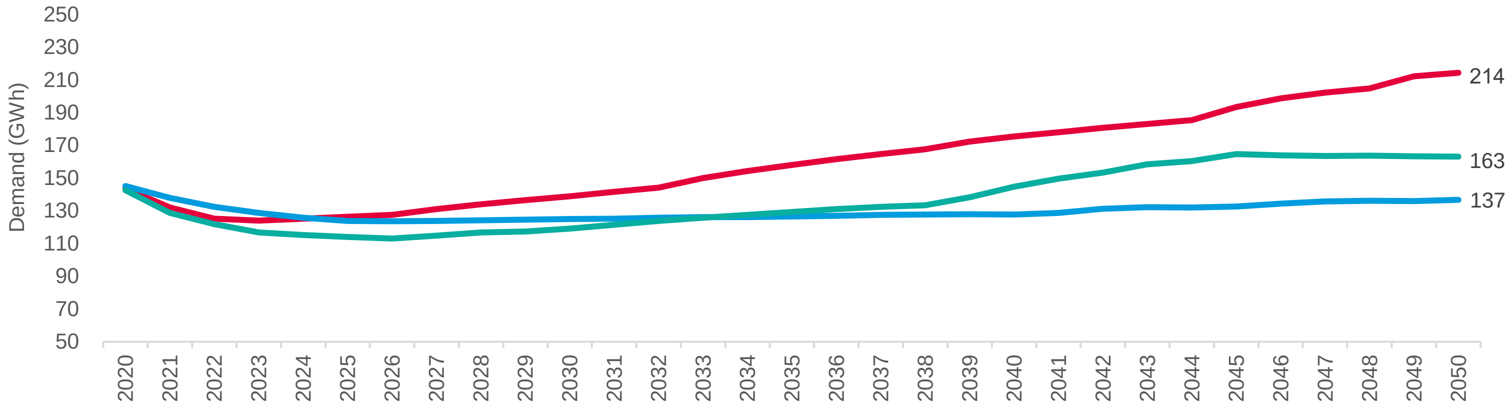
SOURCE: NATIONAL GRID FES

ENERGY EFFICIENCY INDEX FOR APPLIANCE DEMAND IN RESIDENTIAL PROPERTIES (2020F-2050F)

- The highest energy efficiency gains are made under the LtW scenario, with the smallest gains made under the ST scenario.
- These gains are only in relation to non-heating demand.

SOURCE: NATIONAL GRID FES

ELECTRICITY DEMAND FOR EXISTING RESIDENTIAL CUSTOMERS (2020F-2050F)*



- In the short term, across all scenarios, electricity demand from existing customers falls due to the relatively strong gains in appliance energy efficiency, with the greatest reduction in demand associated with the LtW scenario.
- From 2025 onwards, electrification of heating begins to outweigh gains in energy efficiency, which results in electricity demand increasing, particularly under the CT and LtW scenarios as these are associated with the highest penetration of electric heating technologies. Under the ST scenario, due to limited electrification of heating, electricity demand in 2050 doesn't recover to 2020 levels.

SOURCE: ARUP ANALYSIS

The number of new residential customers is driven by the historical relationship between population and residential connections, and the IoM population projections provided by the IoM Government

LEGEND

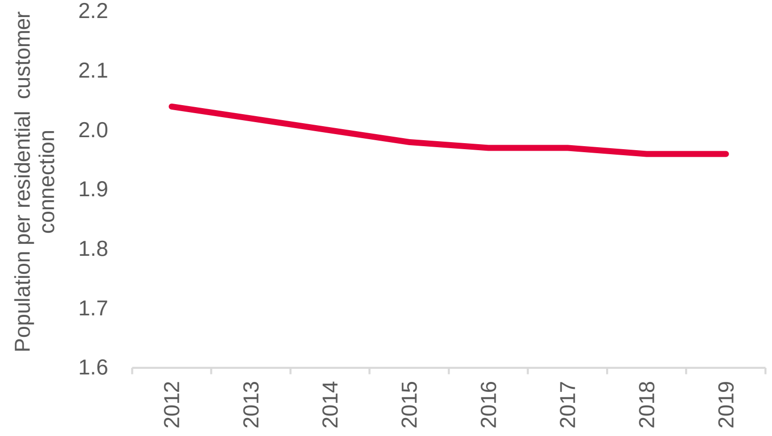
- Population per Residential Customer Connection
- Cumulative New Customer Connections
- Population Forecast

NEW CUSTOMER MODEL ASSUMPTIONS AND SCENARIOS

Assumptions

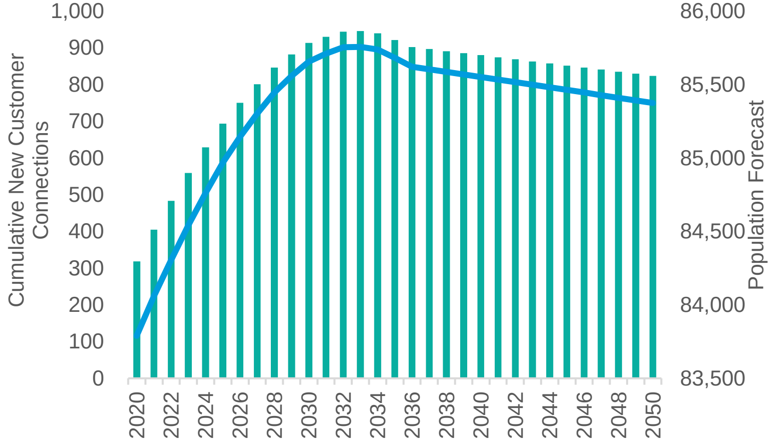
- The number of new customer connections is driven by the historical relationship between population and residential customer connections over a period of eight years (see graph top right) and IoM population projections provided by the IoM government (see graph bottom right).
- All new customers are assumed to benefit from energy efficiency gains. The starting point for new customer electricity demand is lower than existing customers. Five years' worth of energy efficiency gains have been applied upfront to new customer electricity demand to account for this.
- This assumption has been made as new homes will have appliances that are more energy efficient than older homes, so will have a lower starting point for electricity demand per customer.
- We have assumed that **all new customers** use electric heating as their primary source of heating. This is consistent with the IoM's ambition to ban fossil fuel based heating in new homes from 2025 onwards.
- Electric heating customers use **3,198 kWh** per year for heating requirements, which has been calculated from the anonymised MUA billing data.
- Electricity demand from electric vehicles is excluded from residential demand and is considered separately as part of the transport electricity demand.

HISTORICAL RELATIONSHIP BETWEEN POPULATION AND RESIDENTIAL CONNECTION (2012A-2019A)



SOURCE: MUA

CUMULATIVE NEW CUSTOMER CONNECTION GROWTH LINKED TO POPULATION GROWTH (2020F-2050F)



SOURCE: IOM GOVERNMENT DATA, ARUP ANALYSIS

Residential demand: Projected demand from new customer connections

New customer growth occurs until the early 2030s from where the population begins to flatten off and eventually decline. New customer demand follows the same pattern as it is driven by population.

LEGEND

- Consumer Transformation (CT)
- System Transformation (ST)
- Leading the Way (LtW)

***Note**: Electricity demand does not include transmission & distribution losses

NON-HEATING ELECTRICITY DEMAND PER CUSTOMER CONNECTION (2020F-2050F)

- System transformation scenarios is associated with the smallest gains in energy efficiency, whilst the leading the way scenario has the highest gains in EE.
- The starting points differ due to the differences in energy efficiency gains between the scenarios (i.e. five years of energy efficiency gains have been applied to the start point, and since the LtW scenario has the greatest energy efficiency gain in the first five years, its starting point is the lowest.

SOURCE: ARUP ANALYSIS, NATIONAL GRID FES

NEW CUSTOMER CONNECTION DEMAND (2020F-2050F)*

- All new customers are assumed to utilise electric heating and the number of new customers is the same in each scenario. Therefore the only difference in electricity demand from new customers is driven by different energy efficiency gains made in each scenario.
- Accordingly, the greatest demand from new customers results from the ST scenario, whilst the lowest demand is associated with the LtW scenario.

SOURCE: ARUP ANALYSIS

Residential demand: Projected annual demand

Initially, across all scenarios, residential electricity demand falls due to energy efficiency gains. In the medium to long term, demand increases due to electrification of heating and population growth.

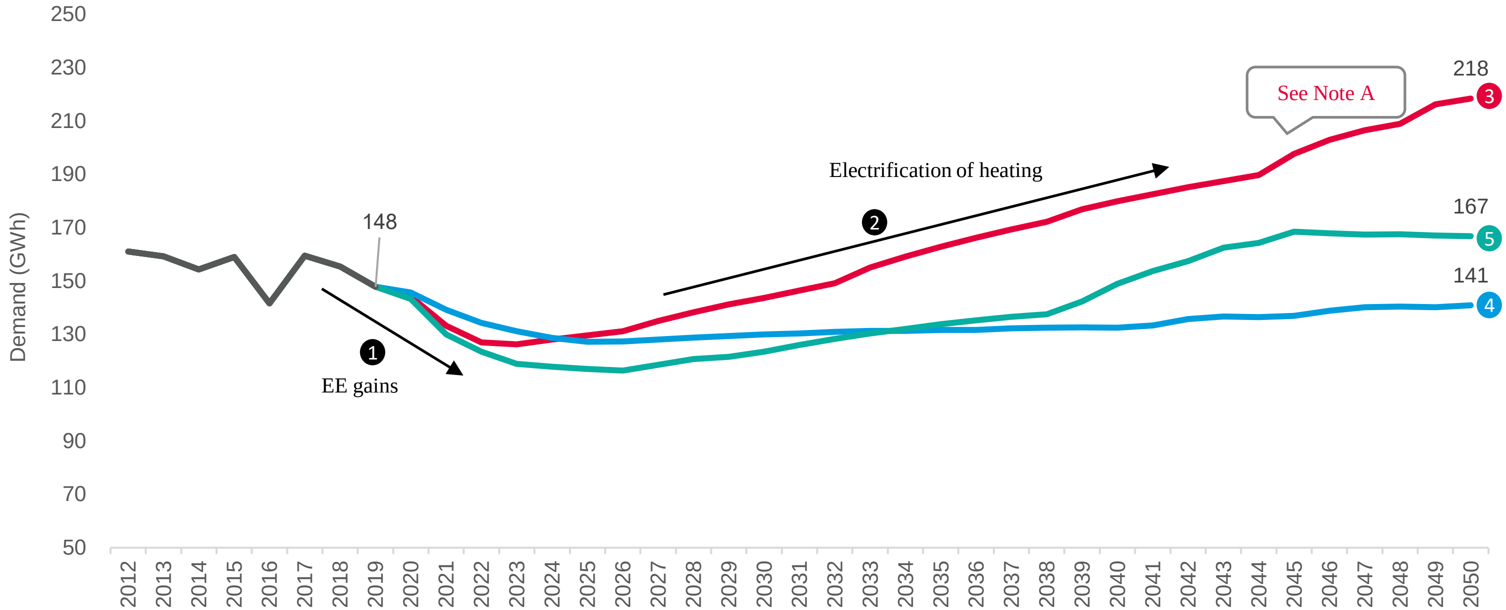
LEGEND

- Historical
- Consumer Transformation*
- System Transformation
- Leading the Way

* Electricity demand does not include transmission & distribution losses

Note A: Small steps in the consumer transformation demand profile beyond 2040 is linked to significant yearly increases in the conversion of existing non-electric heating customers to electric heating (e.g., between 2044 and 2045).

TOTAL RESIDENTIAL CUSTOMER DEMAND (2012A-2050F)*



SOURCE: IOM GOVERNMENT, ARUP ANALYSIS

1. Across all three scenarios, residential electricity demand falls in the short term as energy efficiency gains dominate electrification and new customer growth.
2. In the CT and LtW scenarios, from the mid 2020s (slightly later for LtW), the impact of electrification of heating begins to outweigh the energy efficiency gains which causes electricity demand to increase.
3. The consumer transformation scenario has the highest estimated residential electricity demand by 2050, a 48% increase in electricity demand from 2019.
4. The system transformation scenario has the lowest estimated electricity demand by 2050, a 5% decrease in demand from 2019. This is as a result of residential heating switching to low-carbon alternatives and limited uptake of electric heating.
5. The leading the way scenario sees only a 13% increase in electricity demand between 2019 and 2050, with high levels of electrification of heat (c.60%) offset by high levels of energy efficiency improvements.

Electricity Demand

Industrial and commercial (I&C) demand: Forecasting methodology

Industrial and commercial (I&C) demand has been split into new and existing customers. These two sub-groups have been modelled separately, with their own assumptions and sensitivities.

DEFINITIONS

Customer type	Historical building blocks		Forecasting assumption/input parameters		Scenario sensitivities	Forecasts
Existing customers	Industrial Customers	Demand per Industrial customer		Energy efficiency	Energy efficiency; Electric heating penetration for existing commercial customers	
	Commercial Customers (with EH)	Demand per customer (EH)	Electrification of heating			
	Commercial Customer (no EH)	Demand per customer (no EH)				
Comments	Only commercial customers are split between electric heating and non electric heating customers. This is due to data limitations for industrial customers.		Electrification of heat assumptions overlaid to existing non-electric heating commercial customers. Energy efficiency assumptions applied to both types.			

Customer type	Historical building blocks		Forecasting assumption/input parameters			Scenario sensitivities	Forecasts
New customers	Historical relationship between pop. and ind. customers	Demand per Industrial Customer		Pop. Growth Forecast	Energy efficiency	Energy efficiency	
	Historical relationship between pop. and com. customers	Demand per commercial customer	All new commercial customers use electric heating				
Comments	Historical relationship between population and I&C customers chosen as basis to project future customers.		Population growth forecasts used to project new customer numbers out to 2050. Same energy efficiency assumptions used for new and existing customers.				

SOURCE: ARUP ANALYSIS

Energy efficiency gains are applied to both industrial and commercial customers between 2020 and 2030. Electrification of heating is only applied to commercial customers.

LEGEND

- Commercial Customers
- Industrial Customers

EXISTING CUSTOMER MODEL ASSUMPTIONS AND SCENARIOS

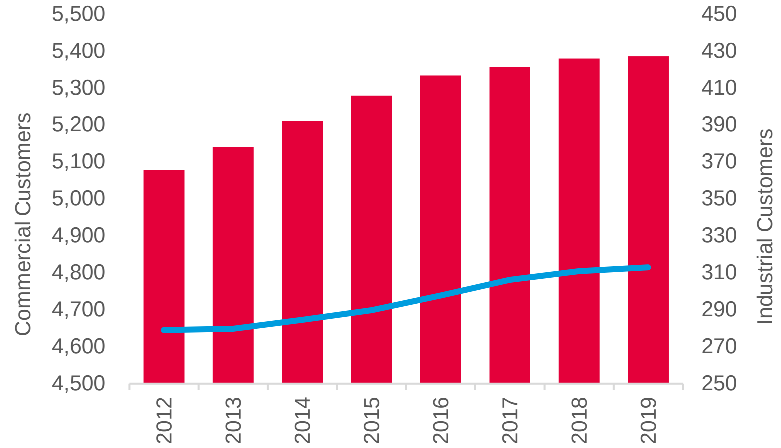
Existing Customers

- It is assumed that the number of existing customers will not decrease over time.
- Energy efficiency gains are applied in the same way to both industrial and commercial customers, in line with FES assumptions. No further energy efficiency gains are applied after 2030 due to the differences of industrial composition between the Isle of Man and the UK, i.e. IoM does not have the same level of industrial activity as the UK, and applying energy efficiency beyond 2030 may result in unrealistic suppression of demand estimates.
- Commercial customers have been split into electric heating and non-electric heating customers using the billing data provided by Manx Utilities. This has not been possible for industrial customers due to the resolution of billing data.
- Arup has assumed that commercial non-electric heating customers will transition away from non-electrified heating solutions at the **same speed and extent** as the FES used for the residential consumers based on the guidance of the IoM Climate Change Transformation Team.
- Due to the nature of the billing data, it is not possible to capture all commercial premises that use electric heating. Hence, there is potential for small underestimation of demand from electric heating from commercial customers. In FY 2019/2020, Arup identified 51 commercial electric heating customers from MUA billing data tariff line Commercial Comfy Heat.

New Customers

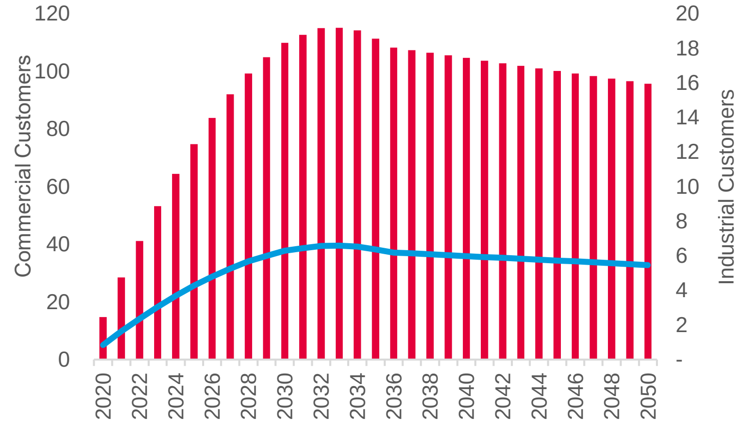
- The number of new industrial and commercial customers are driven by the historical relationship between industrial customers and population, and commercial customers and population respectively, using data between 2016 and 2020. The historical relationship for both these relationships is strong and positive, based on statistical analysis.
- All new commercial customers are assumed to use electric heating, in line with residential customers.

HISTORICAL I&C CUSTOMER CONNECTIONS (2012A-2019A)



SOURCE: MUA BILLING DATA

CUMULATIVE NEW I&C CUSTOMER CONNECTIONS (2020F-2050F)



SOURCE: ARUP ANALYSIS

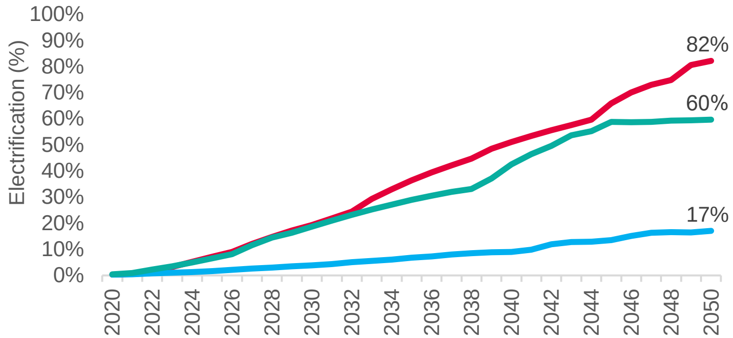
Demand from commercial customers initially falls following energy efficiency gains, but increases as heating is electrified. For industrial customers, once energy efficiency gains are made demand plateaus.

LEGEND

- Consumer Transformation (CT)
- System Transformation (ST)
- Leading the Way (LtW)
- Historical customers
- Projected customers

***Note**: Electricity demand does not include transmission & distribution losses

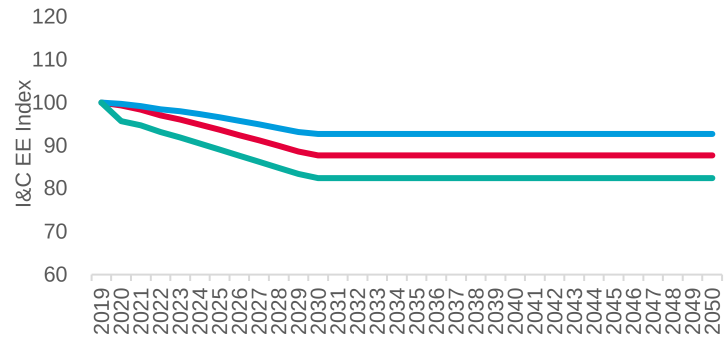
ELECTRIFICATION OF EXISTING COMMERCIAL CUSTOMER HEATING (2020F-2050F)



- Applied only to commercial customers – the electrification profile is identical to residential customers.
- The greatest electrification occurs under the CT scenario, followed by LtW whilst lowest electrification is associated with ST.

SOURCE: NATIONAL GRID FES

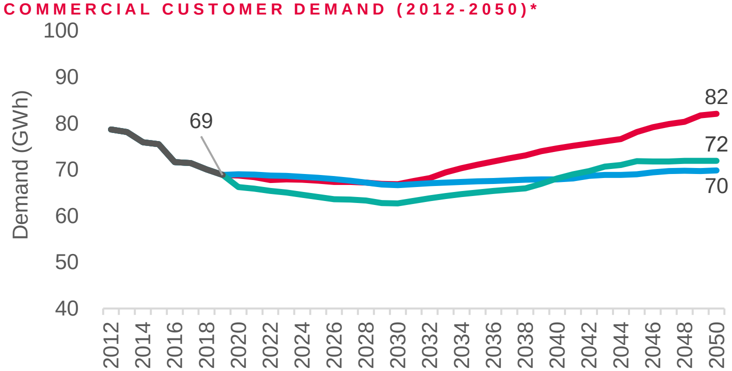
ENERGY EFFICIENCY INDEX FOR I&C CUSTOMERS (2020F-2050F)



- All energy efficiency gains are applied in the first ten year period and are applied to both industrial and commercial customers.
- Consistent with residential customers, the greatest energy efficiency gains are achieved in the LtW scenario, whilst the least are made in the ST scenario.

SOURCE: NATIONAL GRID FES

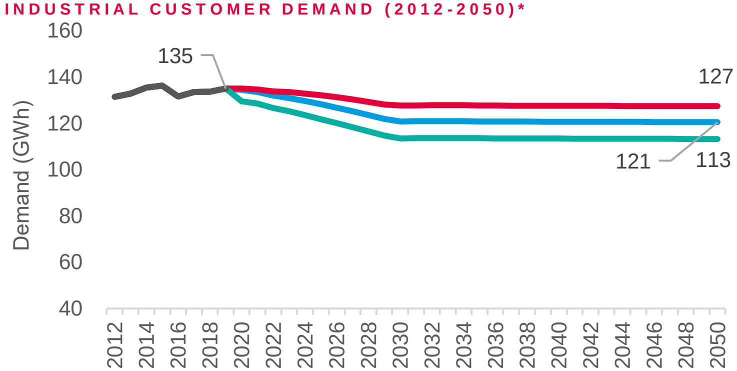
COMMERCIAL CUSTOMER DEMAND (2012-2050)*



- In the short-term, energy efficiency gains outweigh electrification of heating and new customer demand, causing demand to fall.
- In the longer term, heating begins to be electrified in the CT and LtW scenarios which causes commercial electricity demand to increase.

SOURCE: ARUP ANALYSIS

INDUSTRIAL CUSTOMER DEMAND (2012-2050)*



- Only energy efficiency gains have been applied to industrial customers from 2020-2030.
- Demand is expected to remain relatively flat from 2030 onwards, as energy efficiency easy wins are assumed to have been made, and limited additional demand from new customers.

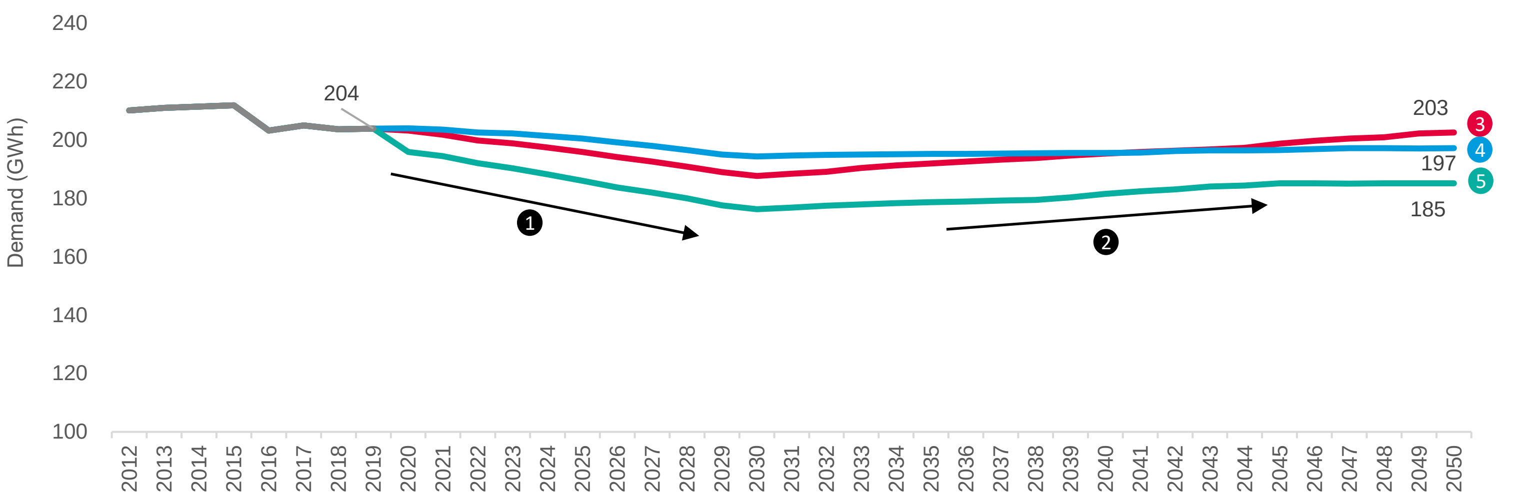
SOURCE: ARUP ANALYSIS

I&C demand is expected to decrease in the long term. This is caused by the downward effect of energy efficiency outweighing the upward effect of new customer growth and electrification of heat.

TOTAL I&C DEMAND (2012A-2050F)*

LEGEND

- Historical
- Consumer Transformation (CT)
- System Transformation (ST)
- Leading the Way (LtW)



SOURCE: IOM GOVERNMENT, ARUP ANALYSIS

***Note**: Electricity demand does not include transmission & distribution losses

1. Across all three scenarios, electricity demand falls in the short-term as energy efficiency gains are made across industrial and commercial premises.
2. In the longer term, post-2030, the CT and LtW scenarios see increases in electricity demand, primarily driven by electrification of heating in the commercial sector. However, across all scenarios, due to the impacts of energy efficiency electricity demand does not recover to meet levels seen in 2019/2020.
3. In the consumer transformation scenario, electricity demand from the I&C sector is projected to fall 1% between 2019 and 2050, the smallest fall in electricity demand across all scenarios. Consumer transformation is associated with the smallest reduction as the commercial sector sees the biggest uptake of electric heating solutions of all scenarios.
4. In the system transformation scenario, pre-2030 electricity demand falls the least as system transformation is associated with the smallest gains in energy efficiency. However, post-2030 in system transformation electricity demand increases the least due to minimal electrification of the commercial sector. Overall, there is a 3% decrease in electricity demand in the I&C sector over the period.
5. In the leading the way scenario, there is aggressive energy efficiency gains observed out towards 2030, resulting in sharpest reduction in electric demand between 2019 and 2030. Post 2030, some of this energy efficiency is offset by new customer growth and electrification of heat in the commercial sector. Overall, electricity demand falls 9% between 2019 and 2050.

Electricity Demand

Transport demand: forecasting methodology

The evolution of electricity demand from the transport sector on the island has been based on trends from the UK, combined with local considerations.

DEFINITIONS

EV – electric vehicles

Customer type	Historical building blocks	Forecasting assumption/input parameters		Scenario sensitivities	Forecasts
Existing customers	Historical electricity demand per electric vehicle (derived from billing data provided by Manx Utilities)	UK population per electric vehicle (FES)	IoM population growth projections	Number of EVs by FES scenario	
Comments	Demand per vehicle estimated from billing data	Arup has made the assumption that IoM EVs per person follows the same trend as that of the UK.			

SOURCE: ARUP ANALYSIS

Transport demand: Alternative fuels for larger vehicles

Larger vehicles on the island are most likely to transition to alternative biofuels or hydrogen in the long term. However, further clarity is required around their transition timelines to assess demand.

HEAVY GOODS VEHICLES (HGVS)

- Many countries across Europe have introduced bans for the sale of Internal Combustion Engine (ICE) car and vans, but there is a lack of policy around similar bans for HGVs.
- This is currently a result of the technical limitations of using alternative fuels in HGVs given the size of these vehicles and the distances they are required to travel.
- However, there is increasing pressure to bring in policy to ban the sale of ICE in HGVs if countries are really going to make their Net Zero commitments by 2050.
- The distances covered by HGVs and the capacity and weight of the battery are challenges to using electricity for road freight.
- Gas (biomethane or hydrogen) is seen as the more favourable option, however there is a lack of refuelling infrastructure and technology readiness at present.
- However, the industry generally sees hydrogen as the fuel with the most potential. And hydrogen is seen as the predominant fuel for HGVs in all net zero scenarios the National Grid FES.
- It is likely that HGVs on the island will decarbonise using alternative biofuels or hydrogen. However, in the absence of a clear transport strategy and policies to drive decarbonisation of HGVs, assessment of electricity demand associated with hydrogen for HGVs has been excluded from this study as agreed with IoM.

BUSES

- Bus fleets are being electrified in many cities in the UK and throughout the world.
- However, public buses have not been considered as part of the electrification of transport in Arup's demand analysis. The IoM government currently has no plans to use electric buses based on the fact the technology doesn't fit the needs of the IoM public bus fleet operated by Bus Vannin.
- The duty cycle of buses available is insufficient for the Isle of Man's transport needs as the nature of services is predominantly inter urban, at higher speeds.
- The island has hilly topography and is 48km long by 16km wide, meaning the buses have relatively long distance, and hilly climbs between stops in comparison to most city bus routes. Therefore, electric buses that can operate short services in big cities elsewhere are unlikely to be fit for purpose on the IoM.
- We envisage like HGVs in the UK, public buses on the island to be fuelled by alternative bio-fuel or hydrogen. However, again, in the absence of a clear strategy to drive the decarbonisation of public transport, assessment of demand associated with hydrogen for buses has been excluded from this study as agreed with the IoM.

HYDROGEN

- Green hydrogen is considered to be the most suitable long term fuel for larger vehicles. However, green hydrogen production technology is nascent. Consequently, green hydrogen production costs are currently not competitive.
- Larger hydrogen fuel cell vehicles are also expensive as the technology is less mature compared to battery electric vehicles, hybrids or internal combustion engines.
- IoM also needs to assess the viability of producing hydrogen on the island vs importing it. It is acknowledged that imported hydrogen will likely need purifying or processing to make it suitable for use in fuel cell vehicles; however, this needs to be weighed against the feasibility of producing the hydrogen on the island.
- The transition to hydrogen in transport is likely to be preceded by the use of biofuels. It is highly unlikely that larger vehicles will switch to hydrogen on the IoM, unless driven by policy or incentive mechanisms, over the medium term. IoM therefore needs to develop a transport strategy with greater clarity on the use of hydrogen in transport applications.
- Given the uncertainties, and as agreed with the IoM Climate Change Transformation Team, electricity demand for hydrogen production has not been factored into the demand assessment.

SOURCE: IOM DEPARTMENT OF INFRASTRUCTURE, NATIONAL GRID FES (2020), BUS VANNIN, PIXABAY, PETER KILLEY

Initially, EV uptake is expected to increase significantly as EVs become competitive with petrol and diesel cars. Post 2040, EV numbers begin to decline due to rise of shared autonomous vehicles and public transport.

LEGEND

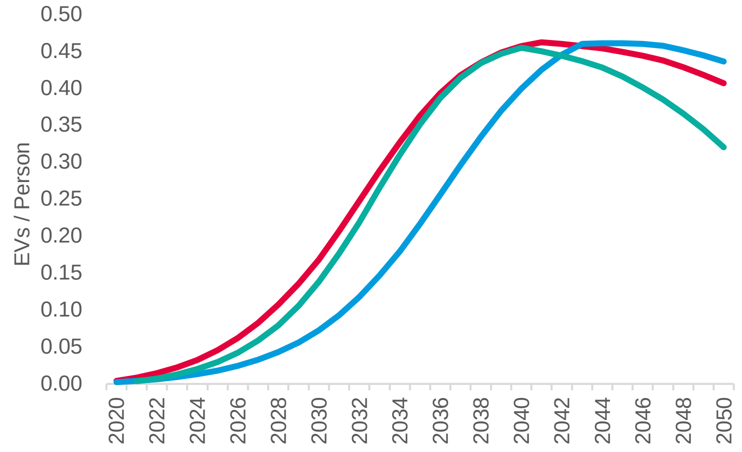
- Consumer Transformation
- System Transformation
- Leading the Way

TRANSPORT DEMAND ASSUMPTIONS

Assumptions

- Arup has assumed that the number of electric vehicles per person in the Isle of Man will mirror that of the UK based on similarities between the two.
- Uptake of electric vehicles (Evs) is dependent on the IoM setting similar targets to the rest of the UK regarding the phasing out of new petrol/diesel cars.
- The drop in the numbers of EVs post 2040 reflects uptake of other forms of transport, e.g. 'active travel', automated self driving vehicles which allow journeys to be shared reducing EV numbers and greater reliance on public transport.
- Using IoM population projections provided by the IoM government, the number of EVs on the IoM can be projected using ratio of EVs per person and total population.
- Arup has assumed that large vehicles, such as HGVs and buses, will not be electrified due to the technological limitation of battery electric vehicles where heavy loads, long distances and quick charging times are required.
- Under all scenarios, all small road transport vehicles will be electric – there will be no remaining small ICE vehicles on IoM roads by 2050.
- Across all scenarios, the electricity demand per EV will remain constant, at c. 4,000 kWh per annum.

NUMBER OF ELECTRIC VEHICLES PER PERSON UK (2012A-2050F)



SOURCE: NATIONAL GRID FES

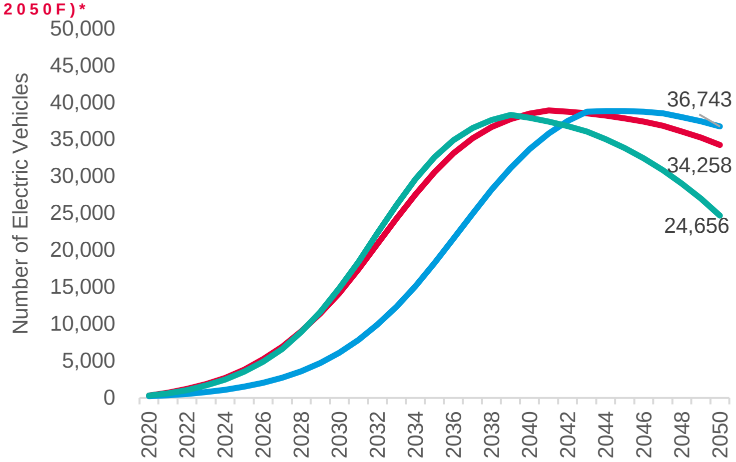
EV numbers and corresponding electricity demand increases significantly from 2025 onwards, as EVs become competitive with petrol/diesel cars.

LEGEND

- Consumer Transformation
- System Transformation
- Leading the Way

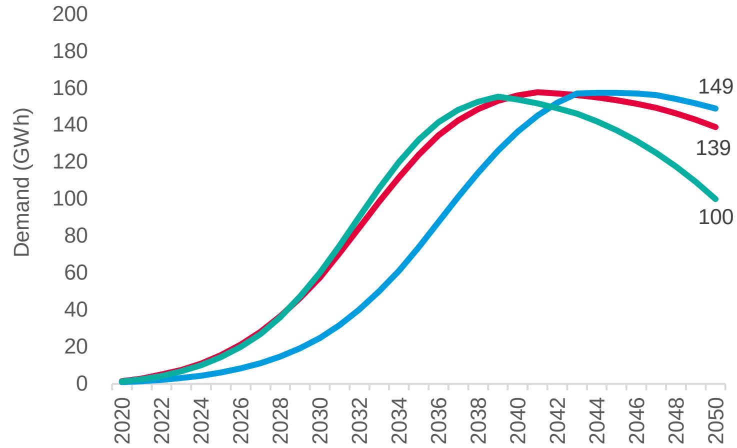
***Note**: Electricity demand does not include transmission & distribution losses

PROJECTED NUMBER OF ELECTRIC VEHICLES ON IOM (2020F-2050F)*



SOURCE: ARUP ANALYSIS

PROJECTED EV ELECTRICITY DEMAND ON IOM (2020F-2050F)*



SOURCE: ARUP ANALYSIS

- The number of electric vehicles increases fastest in the consumer transformation and leading the way scenarios, with electrification of personal vehicles occurring at a slightly slower rate under the system transformation scenario.
- Uptake of electric vehicles is driven by increasing competitiveness of electric vehicles in terms of price and operational abilities. It is assumed that the IoM will also introduce policy to phase out the sale of new petrol and diesel cars.
- In the **consumer transformation scenario**, uptake of EVs begins to happen at pace from 2026, before reaching a peak at 2040. From 2040 onwards, the number of EVs begin to decline as autonomous vehicles become more widespread and there is greater emphasis on public transport and active travel. Accordingly, consumer transformation has the central number of EVs and EV demand.
- In the **system transformation scenario**, the uptake of EVs is slightly slower than the other two scenarios, due to initial reluctance from consumers to switch from petrol and diesel cars to electric cars. However, as the technology continues to improve and come down in price, combined with assumed government initiatives to phase out new petrol and diesel cars, there is a steep uptake of EVs from 2030 onwards. In this scenario, there is less emphasis on autonomous vehicles and car alternatives, which sees the lowest reduction in EV numbers from 2040. Therefore, by 2050, EV numbers and demand are the highest of all scenarios.
- In the **leading the way scenario**, EV uptake follows a similar trend to consumer transformation. From 2040, EV numbers decline significantly due to the highest uptake of autonomous shared EVs and greater reliance on public transport and active travel. By 2050, the leading the way scenario has the lowest EV numbers and EV demand.

Electricity Demand

Projected annual demand evolution

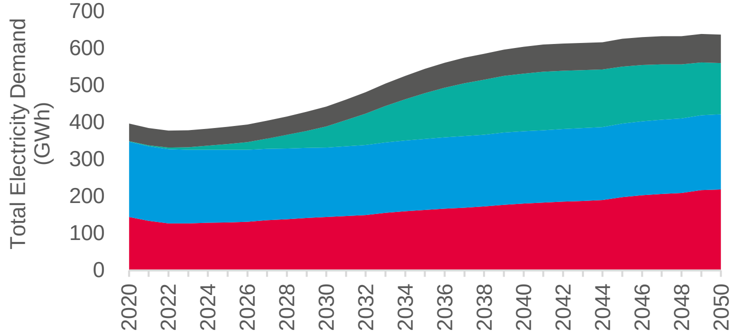
Whilst the total electricity demand and its evolution varies, electrification of transport is the single largest contributor to increasing demand in the long term across all scenarios.

LEGEND

- Losses
- Residential Demand
- I&C Demand
- Transport Demand

*Note: losses represent 12% of total demand

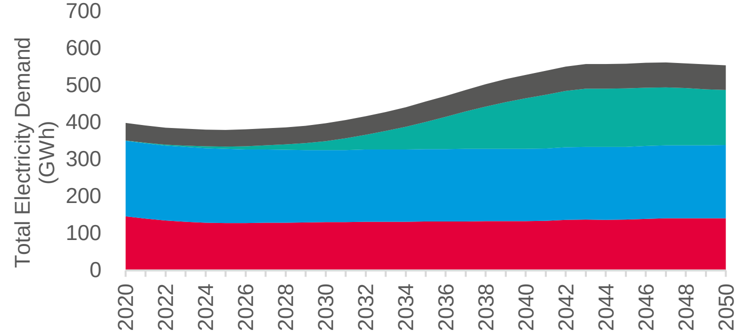
CONSUMER TRANSFORMATION TOTAL ELECTRICITY DEMAND (INCLUDING LOSSES)*



- In the consumer transformation scenario, total demand initially falls due to energy efficiency gains. However, from 2025 the demand begins to increase as residential and I&C demand increase from electrification of heating and transport demand increase as EVs become popular for consumers.

SOURCE: ARUP ANALYSIS

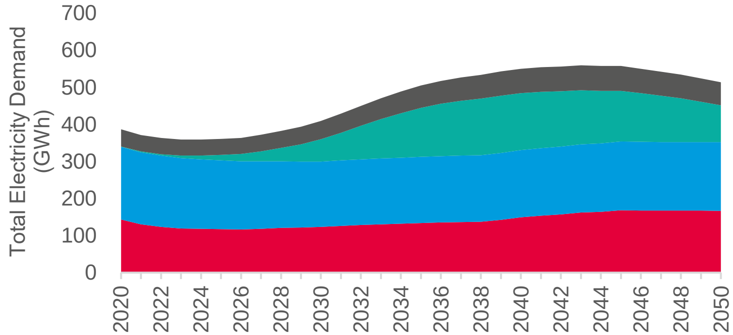
SYSTEM TRANSFORMATION TOTAL ELECTRICITY DEMAND (INCLUDING LOSSES)*



- In system transformation, electricity demand from residential and I&C sectors falls initially due to energy efficiency gains, before flattening out due to relatively minimal electrification of heating across the sectors. EV demand begins to increase significantly from 2030, as EVs begin to dominate the transport sector.

SOURCE: ARUP ANALYSIS

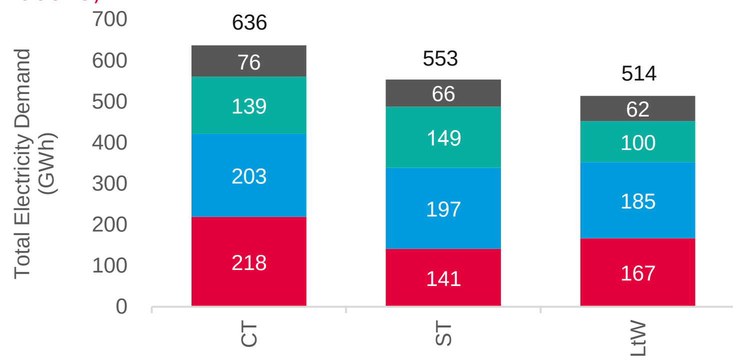
LEADING THE WAY TOTAL ELECTRICITY DEMAND (INCLUDING LOSSES)*



- In the leading the way scenario, demand initially decreases significantly in the short term due to aggressive energy efficiency gains. From 2025, demand begins to increase as a significant proportion of heating is electrified and EV demand begins to take off.

SOURCE: ARUP ANALYSIS

TOTAL ELECTRICITY DEMAND 2050 BY SCENARIO (INCLUDING LOSSES)*



- Consumer transformation is associated with the highest total demand in 2050, due to the greatest number of properties electrified and less energy efficiency gains in comparison to the leading the way.
- System transformation, whilst less electrified, is responsible for more demand than the LtW scenario due to lower energy efficiency gains across the board.

SOURCE: ARUP ANALYSIS

Electricity Demand

Projected annual demand evolution

In the short term, electricity demand is expected to decline across all three scenarios, due to energy efficiency gains. In the long term, CT scenario is expected to have the highest long term increase.

LEGEND

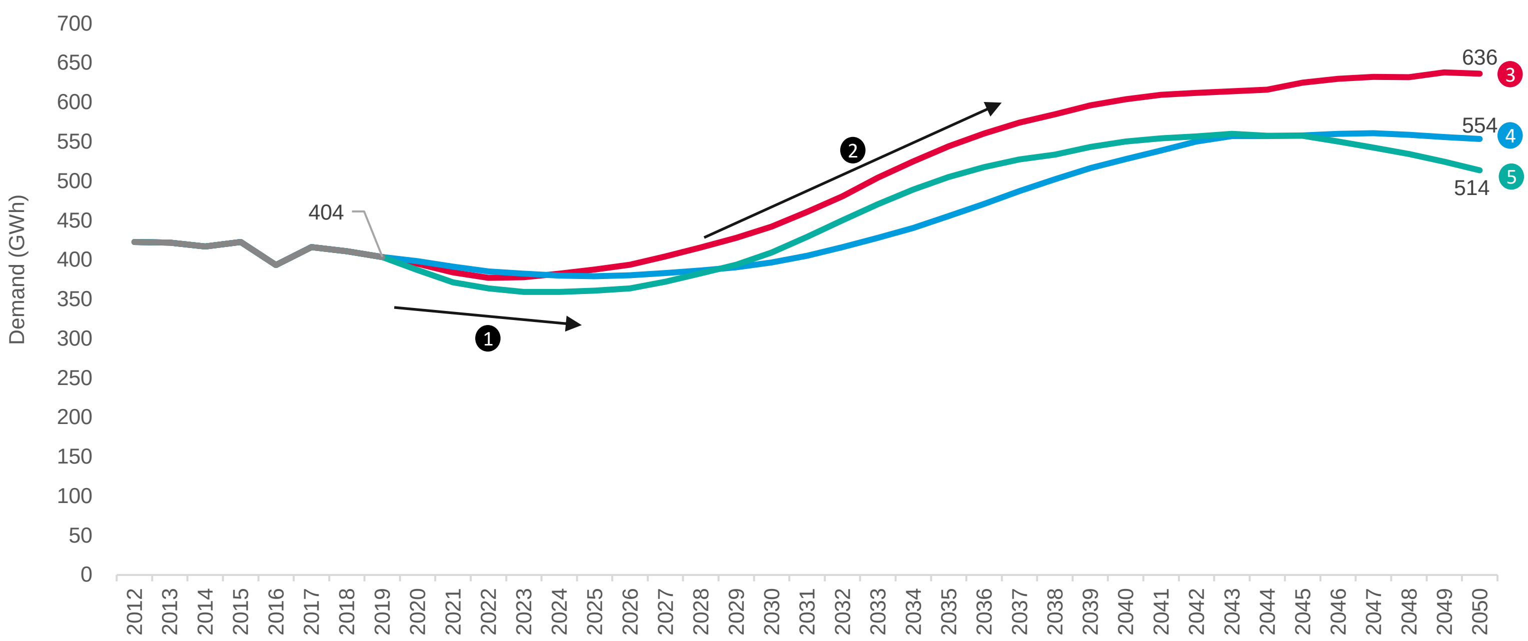
- Historical
- Consumer Transformation**
- System Transformation
- Leading the Way

*Note: losses represent 12% of total demand

NOTE: Covid-19 not factored in as there isn't a full year of data collected yet and IoM stakeholders have confirmed there has been little change in total demand

**Small steps in the consumer transformation demand profile beyond 2040 is linked to significant yearly increases in the conversion of existing non-electric heating customers to electric heating (e.g between 2044 and 2045).

TOTAL ELECTRICITY DEMAND (LOSSES INCLUDED) (2012A- 2050F)*



SOURCE: IOM GOVERNMENT, ARUP ANALYSIS

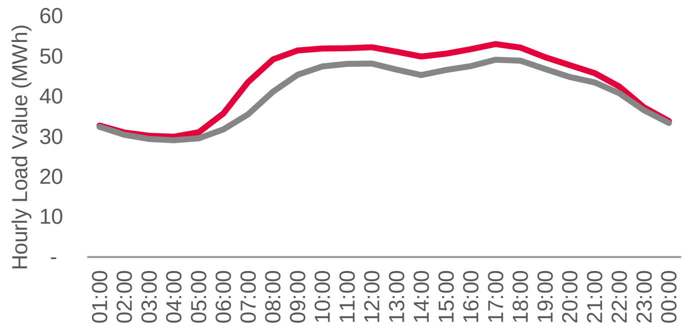
1. Initial decline in electricity demand is driven by energy efficiency gains in the short term.
2. From 2025, electricity demand begins to increase as heating and transport begins to electrify.
3. In the consumer transformation scenario, electricity demand increases the most out of all scenarios, increasing by 58% between 2019 and 2050. This is due to widespread electrification of heat and transport, with less energy efficiency gains than the leading the way scenario.
4. In the system transformation scenario, electricity demand increases by 37% between 2019 and 2050. Whilst system transformation has lower overall electrification of heating, by 2050 there are a greater number of electric vehicles and lower overall energy efficiency gains.
5. In the leading the way scenario, electricity demand increases the least, by only 27% between 2019 and 2050. This is due to the greater energy efficiency gains in this scenario compared to the others.

Both daily and peak demand vary by season and day, with higher demand observed during winter period and weekdays. As with annual demand, the island's peak demand has also declined since 2008.

LEGEND

- Summer Weekday
- Summer Weekend
- Winter Weekday
- Winter Weekend
- Island Peak Demand
- Distribution Peak Demand

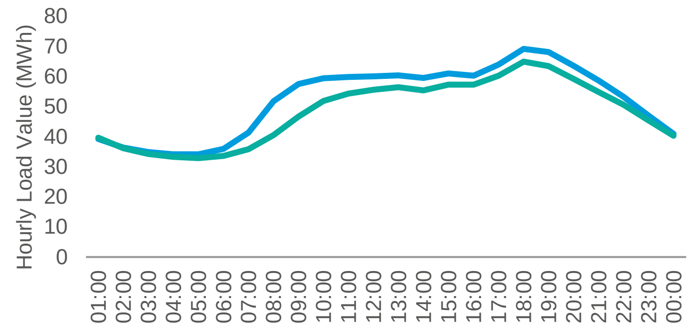
AVERAGE WEEKDAY HOURLY LOAD VALUES BY SEASON (2016A-2019A), ISLAND PEAK USED



- Increased demand over winter period due to the colder temperatures and less daytime hours, largest demand volume in winter at 5-6pm.

SOURCE: MUA DATA

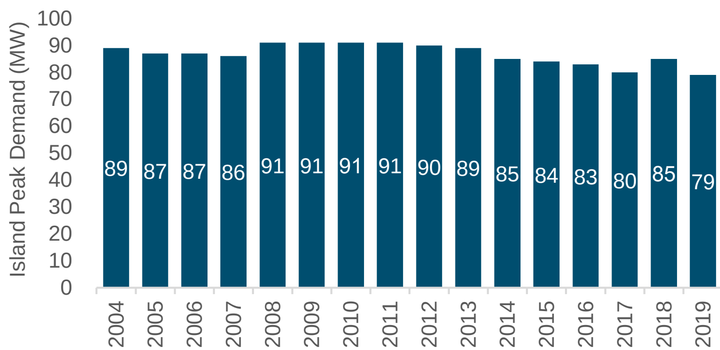
AVERAGE WEEKEND HOURLY LOAD VALUES BY SEASON (2016A-2019A) ISLAND PEAK USED



- Shape of hourly load values similar at the weekend to the weekday, however typically load levels are slightly lower.

SOURCE: MUA DATA

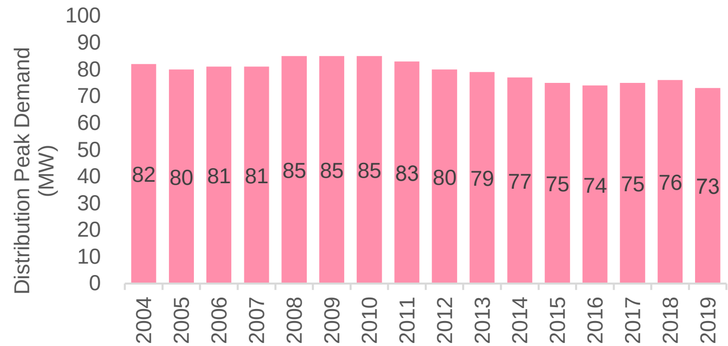
ISLAND PEAK DEMAND (2004A-2019A)



- Island Peak Demand includes transmission losses, interconnector losses and works power.

SOURCE: MUA DATA

DISTRIBUTION PEAK DEMAND (2004A-2019A)



- Distribution peak demand excludes transmission losses, interconnector losses and works power.

SOURCE: MUA DATA

Electricity Demand

Forecasting methodology for annual peak demand

IoM peak demand forecast is driven by outputs from the IoM total electricity demand model, and the historical relationship between IoM peak electricity demand and IoM total electricity demand.

METHODOLOGY NOTE

Forecasting methodology based on statistical analysis of historical annual demand and peak demand relationships, alongside analysis of National Grid FES future projected relationships between peak demand and total demand volume in the UK. Please see following slide for further detail.

Customer type	Historical building blocks	Forecasting assumption/input parameters	Scenario sensitivities	Forecasts
Peak Demand	Historical relationship between IoM annual peak demand vs IoM annual total demand	Outputs from IoM annual total electricity demand model	IoM Electricity Demand Model Scenario Outputs	
Comments	Historical statistical relationship between annual peak demand and annual total demand.	Outputs from model used to project the future IoM annual demand peak.		

SOURCE: ARUP ANALYSIS

Arup's peak demand projections rely on the strong historical relationship, in the GB and IoM, between peak demand and total demand. This same strong relationship is seen in the FES projections for GB.

LEGEND

- IoM Peak Demand
- IoM Total Demand
- FES GB Leading the way (LtW) Peak Demand
- FES GB Leading the way (LtW) Total Demand

PEAK DEMAND PROJECTION ASSUMPTIONS

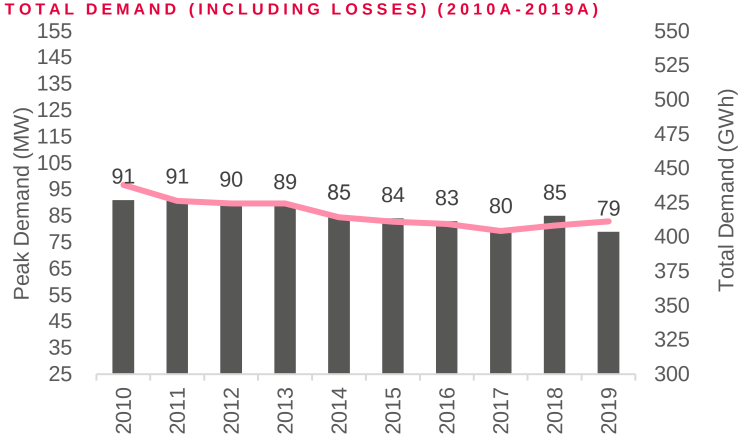
Assumptions

- There is a strong historical correlation between peak demand and total demand on the IoM (both including losses) - please see graph top right.
- There is also a strong correlation between projected GB FES peak demand and projected GB total demand across all scenarios (please see LtW example in graph bottom right). Similarly, there is also a strong relationship between historical GB peak demand and historical GB total demand.
- Given the strong historical and future relationships between peak demand and total demand on the IoM and in GB, Arup has assumed that similarly, there will be a strong relationship between future IoM peak demand and IoM total demand.
- Therefore, the IoM historical relationship between peak demand and total demand volume is used as a basis to project forward the IoM peak demand, using the outputs from the IoM demand volume model.
- Works power has been included in historical peak demand and therefore future projections will include a works power component. Works power is considered a very small component of peak demand. Therefore, it will not make a material difference to projections and hence has not been removed.

Scenarios

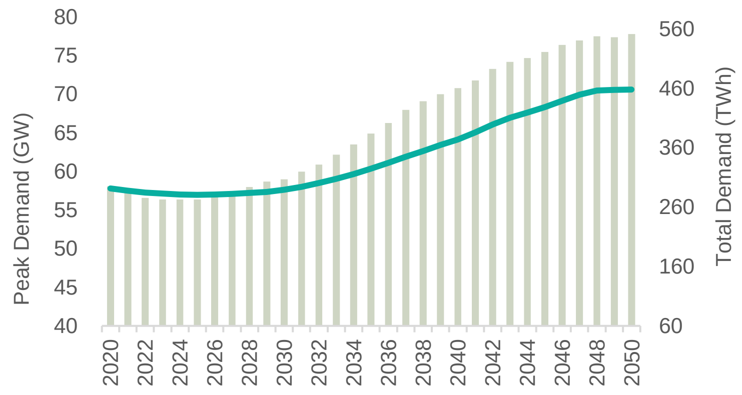
- Arup's IoM electricity demand volume model has three scenarios, CT, ST and LtW.
- Therefore, peak demand projections have been calculated based on each of the three scenarios.

HISTORICAL RELATIONSHIP BETWEEN IOM PEAK DEMAND AND TOTAL DEMAND (INCLUDING LOSSES) (2010A-2019A)



SOURCE: MUA

GB FES LTW PROJECTED PEAK AND TOTAL DEMAND (2020F-2050F)



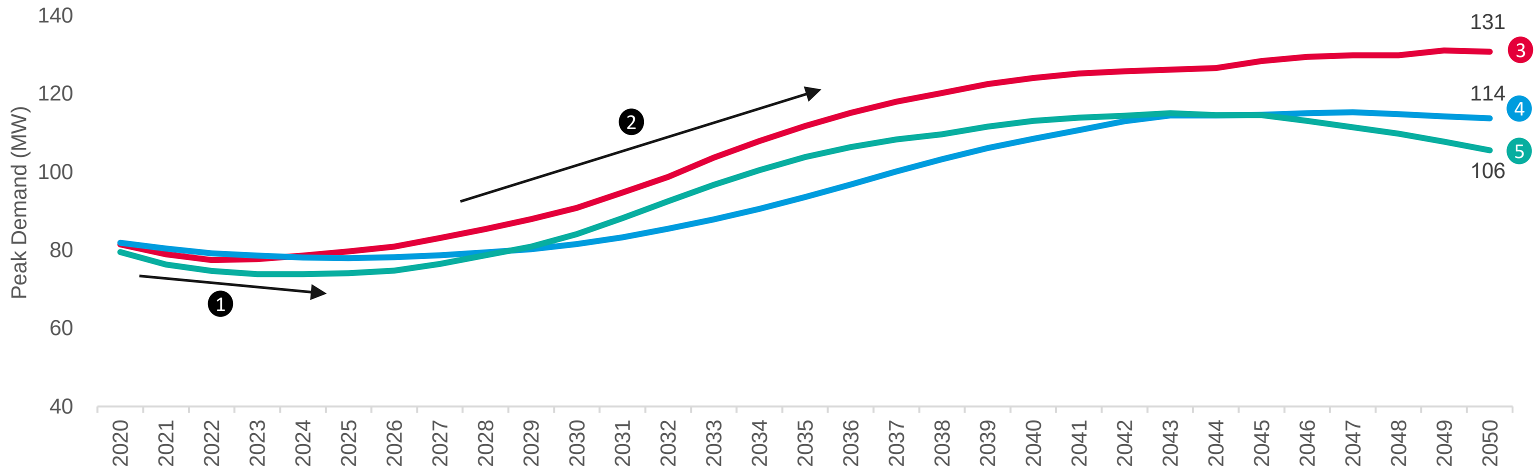
SOURCE: NATIONAL GRID FES
NOTE: Similar relationship between GB FES peak demand and total demand has been found for the Consumer and System Transformation scenarios.

The evolution of peak demand follows a similar pattern to total demand, with the highest peak associated with the consumer transformation scenario and lowest associated with leading the way scenario.

LEGEND

- Consumer Transformation*
- System Transformation
- Leading the Way

IOM PEAK DEMAND PROJECTIONS (INCLUDING LOSSES)* (2020F-2050F)



SOURCE: ARUP ANALYSIS

- Peak demand projections are driven by total electricity demand on the Isle of Man. As a result, projections for peak demand follow a similar trend to the IoM total electricity demand projections.

1. Initially, peak demand falls slightly across all scenarios, due to energy efficiency gains.
2. However, as electricity demand begins to increase from both electrification of heating and electrification of personal transport, the peak demand begins to increase from approximately 2025.
3. The consumer transformation scenario sees the fastest and largest increase in peak demand, as this scenario is associated with the greatest extent of electrification and greatest number of electric vehicles. As a result, the peak demand will be highest under this scenario to meet demand from consumers charging EVs and using electric heating. In the consumer transformation scenario, peak demand increases 66% between 2019 and 2050, up to a peak demand of 131 MW.
4. The system transformation scenario has the central overall final peak demand, with peak demand in 2050 reaching 114 MW, an increase of 44% from 2019.
5. The leading the way scenario has the lowest overall peak demand, resulting from the greatest energy efficiency gains across all sectors and decreasing demand from electric vehicles due to the rise in autonomous vehicles and active transport from 2040. In the leading the way scenario, peak demand reaches 106 MW by 2050, an increase of 34% from 2019.

NOTES:

1. Covid-19 not factored in as there isn't a full year of data collected yet and IoM stakeholders have confirmed there has been little change in total demand.

2. Losses represent 12% of total demand

*Small steps in the consumer transformation demand profile beyond 2040 is linked to significant yearly increases in the conversion of existing non-electric heating customers to electric heating (e.g between 2044 and 2045).

Methodology for forecasting the evolution of hourly peak demand shape

The ENTSO-E hourly peak demand profile for the UK has been used to project the IoM profile out to 2050. EV charging overnight is expected to cause a significant change in the profile as EV penetration increases.

ENTSOE-E assume some electrification of HGVs and assume these will be slow charged overnight in depots.

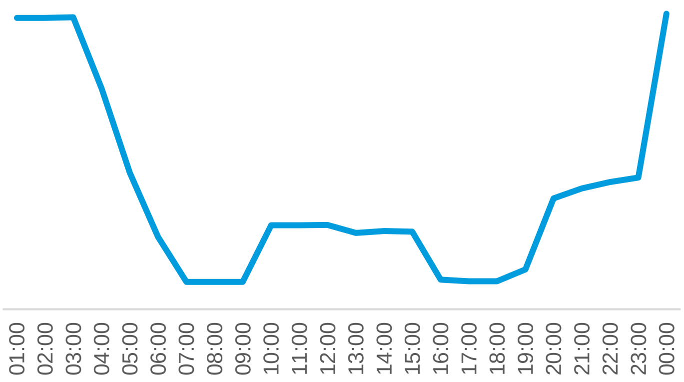
This impact on peak demand shape from overnight electric vehicle charging will likely be more subdued on the IoM, as Arup assume HGVs will follow a hydrogen pathway and won't contribute to this impact (as per the National Grid FES).

METHODOLOGY

- ENTSO-E represents 42 electricity transmission system operators (TSOs) from 35 countries across Europe, thus extending beyond EU borders. Well planned development of new network infrastructure to allow for increased electrification and renewable energy on the system is seen as crucial to maintaining the European Internal Energy Market (IEM).
- To promote this development ENTSO-E has been mandated by EU legislation to deliver biennial Ten Year Network Development Plans (TYPND). The name is misleading as the plans actually go out to 2040.
- We have used hourly shape of demand evolution data from ENTSO-E's TYPND 2020 data, scaled down to the Isle of Man, to produce an IoM shape of demand evolution out to 2050.
- The ENTSO-E Distributed Energy scenario has been selected as it maps to the National Grid FES Consumer Transformation, which has the highest levels of electrification . This ensures the IoM can prepare for the most aggressive scenario of electrification out to 2050 and adapt / re-enforce the network accordingly.
- **The ENTSO-E's TYPND revealed the following findings:**
- **Electric vehicles:** calculated taking existing EV user load profiles but assumes slow charging overnight when the electricity price is low, with this effect on total shape amplifying as more EVs are brought online out to 2050.
- **Electrification of heat:** ENTSO-E focus on the impact of heat pumps replacing traditional electric heating (such as night storage), forecasting the heating load to be distributed over the daily profile as opposed to concentrating it at night.

SOURCE: ENTSO-E

ELECTRIC VEHICLE LOAD PROFILE IN ENTSO-E'S TYPND (2020)



POTENTIAL MECHANISMS TO REDUCE EV IMPACT ON PEAK DEMAND

The following factors would minimise large changes in peak demand caused by EVs on the IoM:

- Public and workplace charging support to avoid large scale residential charging.
- Charging tariffs promoting charging at times which help the grid balance the load.
- Technological improvements such as smart charging, vehicle-to-grid and vehicle-to-home.

The future of electricity demand profiles

The shape of future electricity demand is expected to evolve over time as heating is electrified, and as smart-charging of EVs and smart appliances become the norm.

LEGEND

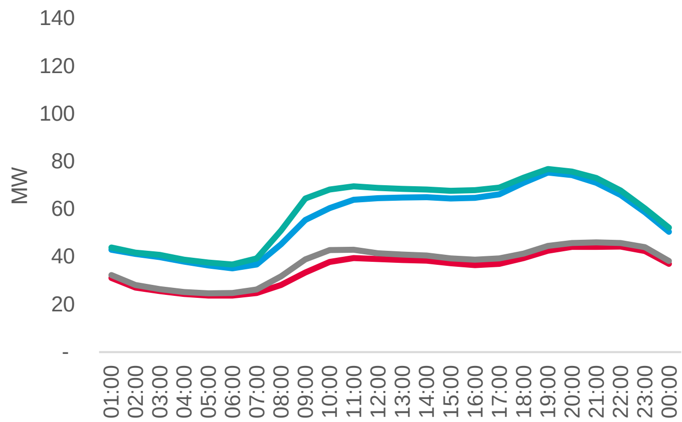
- Summer Weekday
- Summer Weekend
- Winter Weekday
- Winter Weekend

As can be seen from the four charts to the right, the level of demand is expected to rise between 2020 and 2050, as electrification increases.

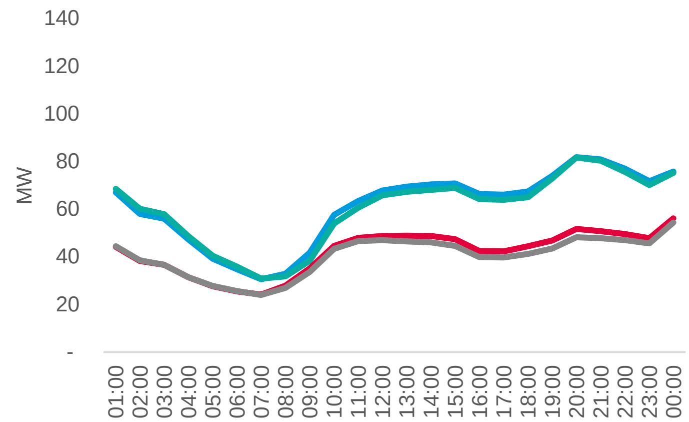
By 2040, EVs are expected to charge "smartly", responding to price signals and charging when the electricity price is low, during the late evening and overnight period.

The peak period is likely to remain between 19:00 and 20:00 until 2040, but there is likely be increased load during the late evening as a result of smart charging of EVs.

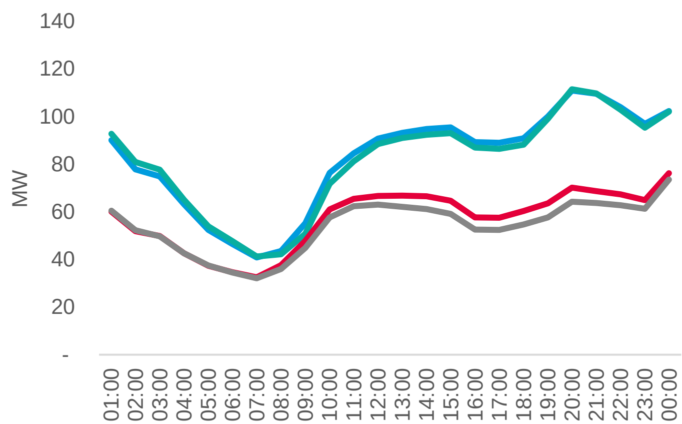
ESTIMATED AVERAGE DAILY PEAK DEMAND PROFILE 2021 (MW)



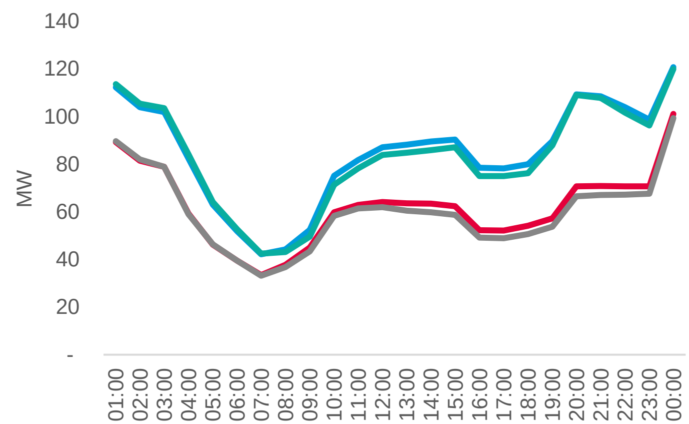
ESTIMATED AVERAGE DAILY PEAK DEMAND PROFILE 2030 (MW)



ESTIMATED AVERAGE DAILY PEAK DEMAND PROFILE 2040 (MW)



ESTIMATED AVERAGE DAILY PEAK DEMAND PROFILE 2050 (MW)

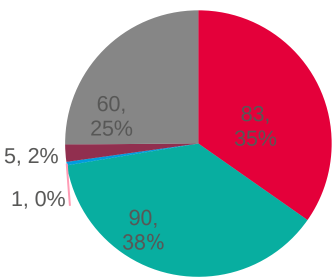


SOURCE: ARUP ANALYSIS

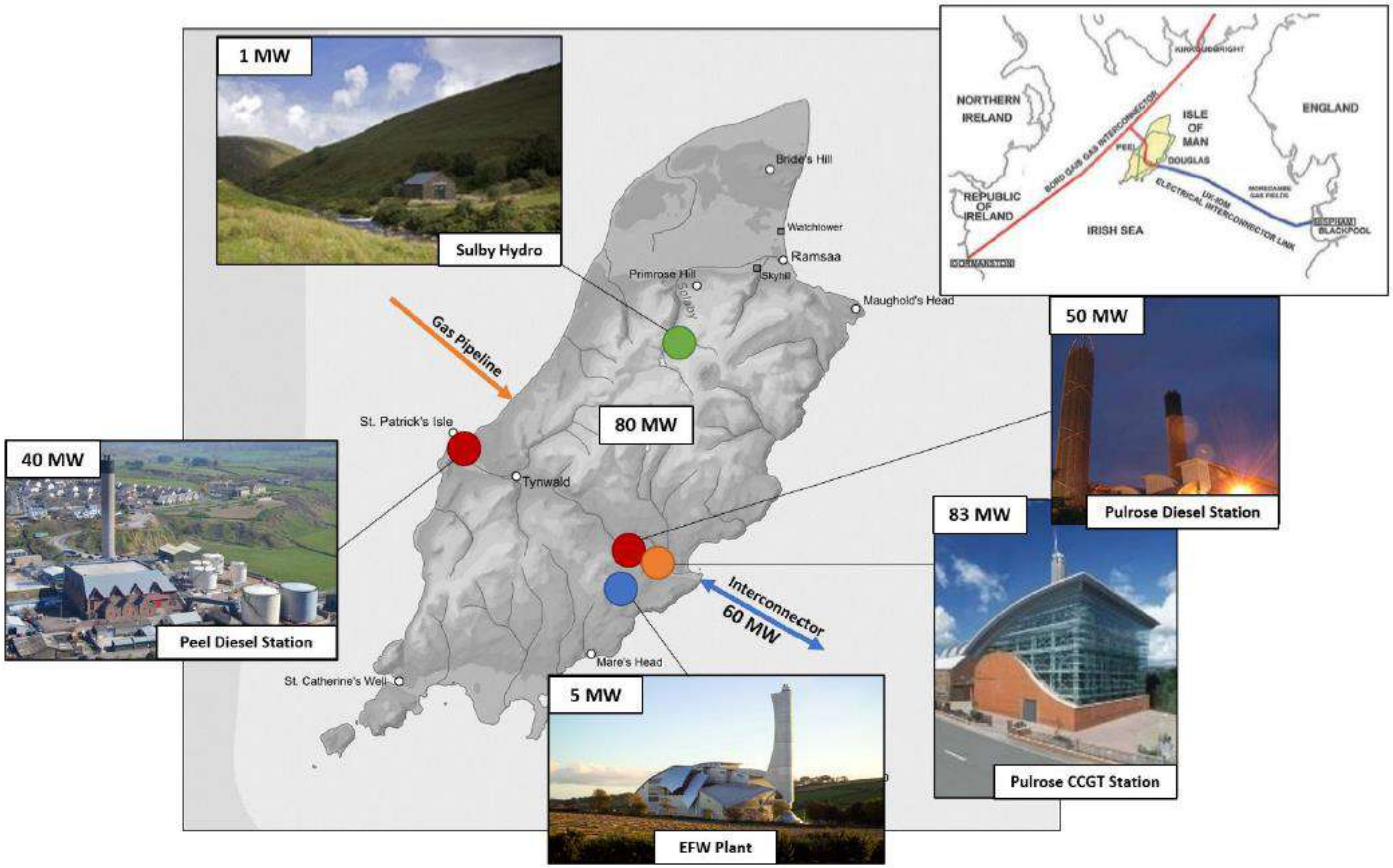
4. MODELLING METHODOLOGY

The existing electricity generation mix on the IoM is mainly comprised of CCGT and diesel generators, and is therefore heavily fossil fuel based. The island is also connected to the UK via an interconnector.

INSTALLED CAPACITY ON THE ISLAND (2021)



- Combined Cycle Gas Turbine (CCGT)
- Diesel
- Energy from Waste (EfW)
- Hydropower
- Interconnector

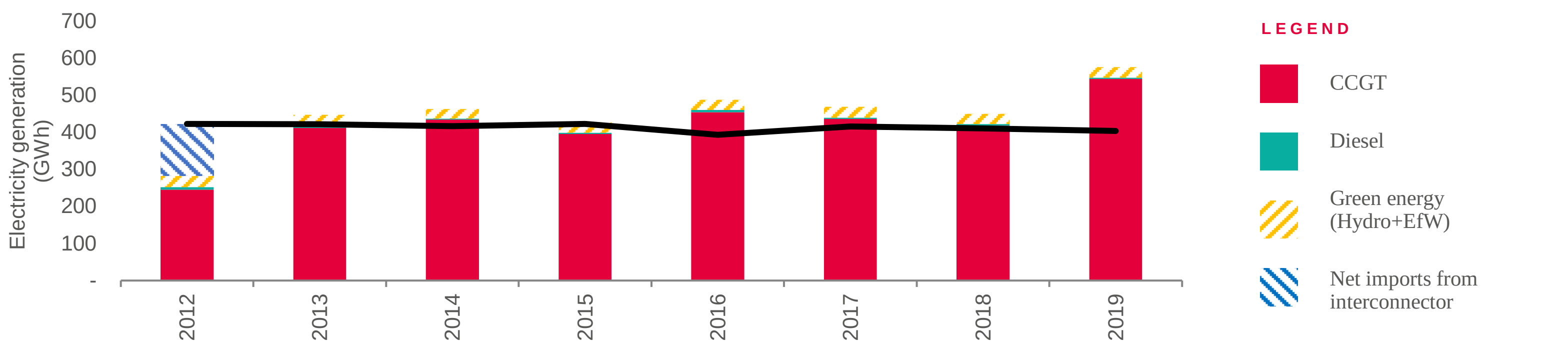


SOURCE: ISLE OF MAN CITIZENS' FORUM ON CLIMATE CHANGE PRESENTATION & MUA

Detailed overview of the current electricity generation infrastructure

Between 2012-2019, approximately 92% of the island's electricity was generated from the CCGT. IoM produces more electricity than it consumes, and is a net exporter to the UK.

HISTORICAL GENERATION MIX ON THE IOM 2012-2019 (GWh)



GENERATION SOURCE KEY INFORMATION

Hydro

- The Hydropower station at Sulby is smallest of the island's generation sources, comprised of two turbines.
- This is the only generation source on the island which is 100% renewable.
- The plant only runs around four months of the year to conserve water as its source is also used for potable water.

EfW

- The island's EfW plant burns municipal and some agricultural waste.
- This currently runs at c. 60% capacity because there isn't sufficient fuel or waste on the island to feed it.
- It is understood that unlike the CCGT or diesel plants some gases are chemically captured but not CO2.

Interconnector

- The island is connected to the UK electricity network via a 60MW AC interconnector.
- The IoM is a net exporter. It has excessive generation capacity compared to local demand on the island, and a lack of carbon tax on the island enables it to sell electricity to the UK at competitive rates.
- It is an AC interconnector, which allows the island to benefit from the UK National Grid assisting with balancing the grid and providing ancillary services to the IoM.

CCGT

- Commissioned in 2003, this is the primary energy generation source on the IoM.
- The gas turbines burn natural gas, a fossil fuel, fed from the UK by pipeline
- When the CGT is running at full capacity it is understood to emit 400 kg of CO2 per MWh.
- The plant is composed of two Gas Turbines (GT) and one Steam Turbine (ST).
- The GTs are 30MW each, but usually limited to 27 MWe for temperature reasons, and typically run at c.20MW.
- The ST is 23 MW but due to efficiency reasons it runs at 20MW or lower.
- **When the AC interconnector is down, the CCGT can only operate in OCGT mode, reducing it's capacity to c.60MW.**

Diesel Generators

- There are nine diesel generators on the island. Five at the Pulrose Power Station and four at Peel Power Station.
- These generators are not seen as a primary generating source for electricity, but to provide back up power when there are problems with other generation sources such as the CCGT.
- In addition to back up power, they have been used historically for commercial reasons so IoM can sell this electricity to the UK. However there is now limited opportunity to continue doing this given changes to TRIAD.
- They burn diesel, a fossil fuel, and as a result each emit 700 kg CO2 per MWh.

SOURCE: MUA

The increase in electricity demand and the requirement to reach net zero emissions by 2050 will have significant implications for the electricity generation mix.

KEY DRIVERS

Policy

The IoM's legally binding target to reduce emissions to Net Zero by 2050 will influence the supply mix as the energy industry shifts to cleaner sources.

Technology

As growth stimulates innovation, energy technologies will continue to advance. Advancements in storage, asset life, reliability, efficiency, smart-use, etc. will influence the future power generation mix.

Cost

Reduction in technology costs, innovative financing methods and reducing risks following increased learning will influence the economics of individual technologies and the choices that drive the transition to Net Zero.

IMPACT ON THE GENERATION MIX

Renewables

The IoM has a largely fossil fuel based electricity generation mix. Introduction of renewables whether solar or wind, can greatly increase the renewable component of the generation mix. Reports such as the IMPACT and AEA report suggest there is large potential to upscale the use of these technologies on the IoM.

Storage

Technological innovation and cost reduction in battery technology is expected to enable greater energy storage capacity. This is essential to support the growth in renewables and maximise utilisation, given the intermittency issues associated with renewable technologies.

Low Carbon Technologies

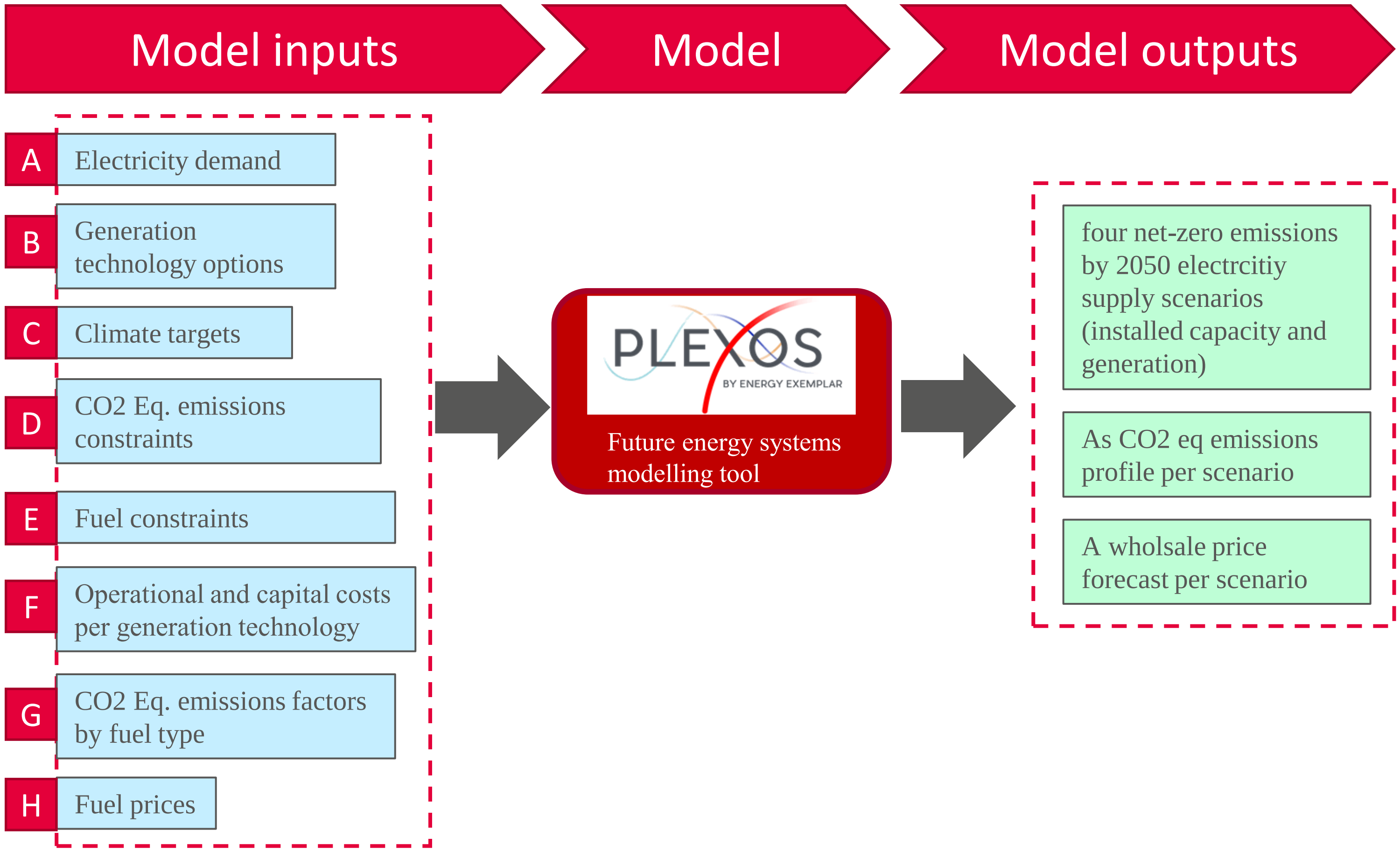
Low or zero carbon technologies such as biomass, energy from waste and hydrogen will play a vital role in meeting the future electricity baseload and mitigating the issues related to intermittency of renewables. However, local constraints may impact the viability of some of these technologies.

Interconnector

As neighbouring countries such as the UK begin to increase the amount of carbon neutral or renewable electricity in their generation mix, there will be more green electricity available to purchase. The IoM could import more of this electricity and help reduce the amount of fossil fuel base electricity consumed on the IoM. Additionally, interconnectors can be used to help with certain grid operations such as inertia and frequency response.

SOURCES: GOV.UK (2019); IMPACT REPORT (2019); AEA RENEWABLE ENERGY SUSTAINABILITY STUDY(2010) ZERO CARBON BRITAIN, CAT (2019)

Arup has developed four scenarios for the island's future electricity generation mix using the Plexos modelling tool. The model was built using a number of island-specific inputs and assumptions.



SOURCE: ENERGY EXEMPLAR: ARUP ANALYSIS

Modelling Methodology

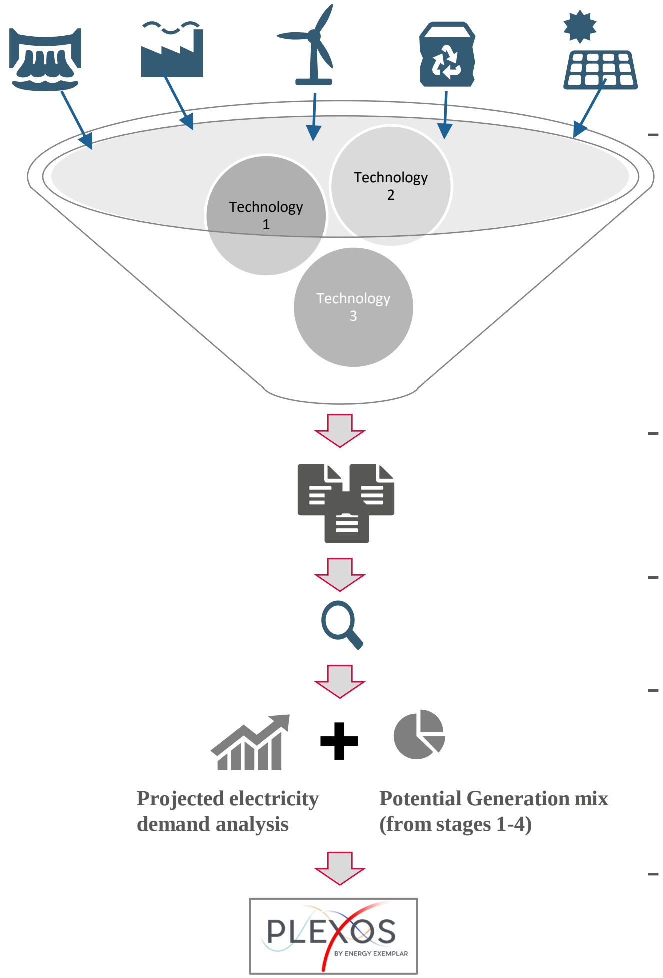
Methodology for producing generation mix scenarios on the Isle of Man

B | Generation technology options

To the support the transition away from a fossil fuel based generation, Arup identified a long-list of potential technologies and assessed these against a set of criteria to identify a suitable shortlist.

Plexos is the modelling tool Arup employ for modelling future energy scenarios

ARUP APPROACH



Stage 1- Generating technology longlist identification

Stage 2- Multi-criteria Assessment (MCA)

Stage 3- Generating technology shortlist

Stage 4- Reviewing shortlist based on local considerations

Stage 5- Plexos Energy Model Inputs

Stage 6- Generation mix for future energy scenarios.

WHY THE ARUP APPROACH?

- A holistic approach is important as it ensure all possible technologies are considered and ***nothing is excluded.***
- Screening the long list through a multi-criteria assessment ensures only the ***most suitable*** technologies are ***identified.***
- Once an initial shortlist is identified, understanding the feasibility of these technologies in the context of the Isle of Man is necessary to ensure MCA scores are ***reviewed*** and ***challenged.***
- Focusing on a smaller number of ***relevant opportunities*** means time is spent ***efficiently*** and ***usefully*** when developing these scenarios further in the modelling process.

SOURCE: ARUP ANALYSIS

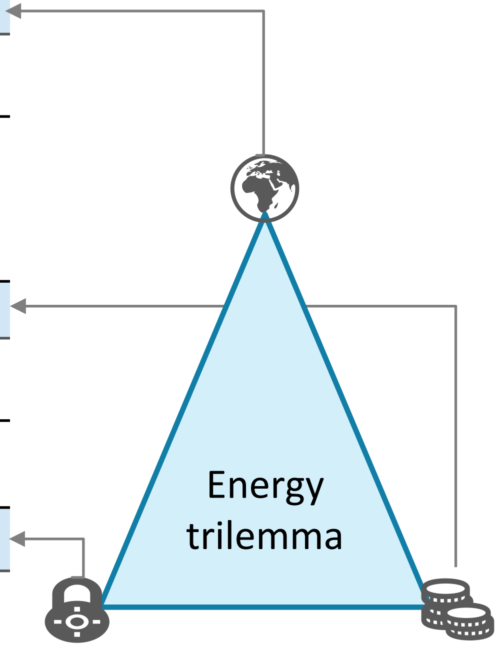
Multi-Criteria Assessment (MCA): Definitions

B Generation technology options

The multi-criteria assessment (MCA) was comprised of seven individual criteria, aligned to the widely recognised energy trilemma.

CRITERIA SUMMARY TABLE

Criteria	Criteria Definition	Scoring Mechanism
Energy trilemma consideration 1: Environmental impacts of electricity supply		
Renewable / Low Carbon	Is the technology a renewable or low carbon option? (If low carbon climate targets could still be achievable)	0 = No. 1 = Lower carbon than traditional fossil fuels. 2 = Low carbon but not renewable. 3 = 100% renewable.
Compatibility to 2025 ambition	Can this technology be deployed in time to help the IoM reach its ambition of 20 MWe of installed capacity coming from carbon neutral or renewable sources by 2025? Cognisant of the island's 2035 and 2050 target.	1 = No (not a low carbon/renewable technology or timescale too short for commissioning technology). 2 = potentially, although building enough capacity could be an issue. 3 = Yes.
Energy trilemma consideration 2: Cost / Affordability of electricity supply		
LCoE in 2025	LCoE of electricity relative to other available technologies if being commissioned in 2025.	1 = 4^{th} Quartile. 2 = 3^{rd} Quartile. 3 = 2^{nd} Quartile. 4 = 1^{st} Quartile.
LCoE in 2035	LCoE of electricity relative to other available technologies if being commissioned in 2035.	1 = 4^{th} Quartile. 2 = 3^{rd} Quartile. 3 = 2^{nd} Quartile. 4 = 1^{st} Quartile.
Energy trilemma consideration 3: Security of Electricity Supply		
Suitability for IoM	Is the scale of this technology appropriate for the IoM (e.g., large scale nuclear too large for the Island's requirements) and is their any resource constraints (including natural resources)?	1 = Not suitable in terms of scale or resource availability. 2 = Scale suitable or resources available but not both. 3 = Scale suitable and available resources.
Technology readiness	Is the technology ready for commercial deployment?	1 = No. 2 = Not yet but has the potential to be over the within the next c.10 years. 3 = Commercially deployed already.
Dispatchability	Does technology have dispatchability?	1 = Yes. 0 = No.



SOURCE: ARUP ANALYSIS

SOURCE: ARUP ANALYSIS

B Generation technology options

Levelised Cost of Electricity analysis was completed for project commissioning in 2025 and 2035, with the latter meeting the IoM Government's first climate target.

SCORING LEGEND

Projects commissioning in 2025		
Quartile	LCoE (£/MWh)	MCA Score
Q1	< 56	4
Q2	56-96	3
Q3	97-177	2
Q4	>178	1

Projects commissioning in 2035		
Quartile	LCoE (£/MWh)	MCA Score
Q1	< 49	4
Q2	59-102	3
Q3	103-177	2
Q4	>178	1

*Interconnectors are not typically scored using an LCoE, but due to the procurement flexibility and export sales potential they have scored highly, despite construction capex requirements.

**only peaking plant LCoE available in BEIS report.

CRITERIA SUMMARY TABLE

Technology	Sub-Type	LCoE (£/MWh) projects commissioning in 2025	MCA Score (1-4)	LCoE (£/MWh) projects commissioning in 2035	MCA Score (1-4)
Interconnectors	Interconnectors	*Flexibility to control LCoE, but dependent on procurement strategy	4	*Flexibility to control LCoE, but dependent on procurement strategy	4
Waste	Waste	39	4	36	4
Solar PV	Large scale Solar PV	44	4	36	4
Onshore Wind	Onshore Wind >=1MW	46	4	44	4
Onshore Wind	Onshore Wind <1MW (Onshore high estimate)	52	4	50	3
Offshore Wind	Offshore Wind	57	3	43	4
CCS	Thermal CCS Post Combustion (FOAK)	85	3	81	3
Hydro	Hydro (5-16 MW)	88	3	88	3
Nuclear	Large scale Nuclear (PWR FOAK, 2014 prices)	95	3	95	3
Biomass	Biomass (dedicated)	98	2	98	3
Fossil Fuel	CCGT	85	3	115	2
Solar PV	Micro-generation Solar PV (<4kW)	114	2	107	2
Nuclear	SMRs	124	2	124	2
Geothermal	Geothermal CHP	133	2	121	2
Hydrogen	Hydrogen CCGT (blue)	175	2	175	2
Fossil Fuel	Gas Reciprocating Engines (500 hr)**	188	1	244	1
Tidal	Tidal	253	1	188	1
Fossil Fuel	OCGT (100MW 500 hr)**	315	1	361	1
Fossil Fuel	Diesel (Recip Diesel 500 hr) **	245	1	313	1

SOURCE: BEIS ELECTRICITY GENERATION COSTS (2016 & 2020) AND ARUP ANALYSIS

Multi-Criteria Assessment (MCA): summary scores

B Generation technology options

The findings from the MCA helped assess the suitability of individual technologies. This in turn informed a subsequent workshop with key stakeholders focused on identifying a pool of suitable technologies.

ADDITIONAL COMMENTS

*It is important to note that environmental credentials of biomass continue to be a subject of scientific debate. Nevertheless, biomass is technically classed as a renewable technology.

**LCoE data is not readily available for natural gas blended with hydrogen. However, since hydrogen is more expensive than natural gas, and will continue to be so for some time, the LCOE of this technology is assumed to be higher, reflecting a low score. Additionally, substantial modifications are likely to be needed to the existing plant on the island to make it suitable for blended hydrogen gas.

Category	Type	SubType	Renewable / Low Carbon (0-3)	Will this enable the IoM to hit 2025 target (1-3)	Energy trilemma consideration 1: Environmental	LCOE in 2025 (1-4)	LCOE in 2035 (1-4)	Energy trilemma consideration 2: Cost	Suitability to IoM (Scale and natural resource availability) (1-3)	Technology readiness (Commercially ready to deploy)(1-3)	Dispatchability (1-0)	Energy trilemma consideration 3: Security of supply	Weighted total score (out of 3)	Rank
	Interconnectors		2	3	0.83	4	4	1.00	3	3	1	1.00	2.83	1
Renewable	Onshore Wind	Onshore Wind >=1MW	3	3	1.00	4	4	1.00	2	3	0	0.71	2.71	2
Renewable	Solar PV	Large scale Solar PV	3	3	1.00	4	4	1.00	2	3	0	0.71	2.71	2
Renewable	Waste	Waste	2	3	0.83	4	4	1.00	2	3	1	0.86	2.69	4
Renewable	Onshore Wind	Onshore Wind <1MW	3	2	0.83	4	3	0.88	2	3	0	0.71	2.42	5
Renewable	Offshore Wind	Offshore Wind	3	1	0.67	3	4	0.88	3	3	0	0.86	2.40	6
*Renewable	Biomass	Biomass	2	3	0.83	2	3	0.63	2	3	1	0.86	2.32	7
Low Carbon	CCS	Thermal with CCS	3	1	0.67	3	3	0.75	3	2	1	0.86	2.27	8
Low Carbon	Nuclear	Large scale Nuclear	3	1	0.67	3	3	0.75	1	3	1	0.71	2.13	9
Renewable	Hydro	Hydro	3	1	0.67	3	3	0.75	1	3	1	0.71	2.13	9
Renewable	Solar PV	Micro-generation Solar PV	3	2	0.83	2	2	0.50	2	3	0	0.71	2.05	11
Low Carbon	Nuclear	SMRs	3	1	0.67	2	2	0.50	3	2	1	0.86	2.02	12
Renewable	Geothermal	Geothermal	3	1	0.67	2	2	0.50	1	3	1	0.71	1.88	13
Thermal	Fossil Fuel	CCGT	0	1	0.17	3	2	0.63	3	3	1	1.00	1.79	14
Renewable	Tidal	Tidal	3	1	0.67	1	1	0.25	3	3	0	0.86	1.77	15
Thermal	Hydrogen	Hydrogen CCGT	2	1	0.50	2	2	0.50	2	2	1	0.71	1.71	16
Thermal	Fossil Fuel	CCGT (**Blended with hydrogen)	1	1	0.33	2	2	0.50	3	2	1	0.86	1.69	17
Thermal	Fossil Fuel	Gas Reciprocating Engines	0	1	0.17	1	1	0.25	3	3	1	1.00	1.42	18
Thermal	Fossil Fuel	OCGT	0	1	0.17	1	1	0.25	3	3	1	1.00	1.42	18
Thermal	Fossil Fuel	Diesel	0	1	0.17	1	1	0.25	3	3	1	1.00	1.42	18

SOURCE: ARUP ANALYSIS

B Generation technology options

The assessment of individual technologies was challenged and refined through a workshop with key stakeholders. Technologies that could support the island's transition, and the associated rationale, were also identified (1/2)

NOTE

- The multi-criteria assessment that informed evaluation of individual technologies.
- The evaluation takes into account the energy trilemma, the conditions and requirements on the island, and the challenges described on previous pages around intermittency, technology maturity, infrastructure requirements etc.

Category	Type	Sub-Type	Included or Excluded	Supporting rationale
Renewable	Interconnectors	Interconnector	Included	Interconnectors provide multiple benefits including resilience, dispatchability, grid operability, export / import opportunities. They are a carbon neutral technology and can also enable purchase of clean energy via a power purchase agreement (PPA).
	Offshore Wind	Offshore Wind	Included	These technologies are low-cost and zero carbon. They are vital for the transition and hence included in the model.
	Onshore Wind	Onshore Wind >=1MW		
	Onshore Wind	Onshore Wind <1MW		
	Solar PV	Large scale Solar PV		
	Solar PV	Micro-generation Solar PV		
	Biomass	Biomass	Included	Natural resource available on the island, albeit limited to 30kT per annum. Biomass is considered to be a zero carbon technology.
	Hydro	Hydro	Included (existing only)	Existing plant included and assumed to remain operational at least until 2050. Model is constrained from building new hydropower due to lack of resource availability.
	Geothermal	Geothermal	Excluded	Based on a high level review of publicly available geothermal heat maps and discussions with key stakeholders, the geological conditions are not considered to be suitable for large-scale geothermal technology
	Tidal	Tidal	Excluded	Whilst technology is mature, tidal power plants are expensive to justify purely on a cost and benefit analysis. Unless a wider strategic requirement is identified, tidal power is unlikely to be feasible for IoM for the purposes of serving its own electricity demand.
Low Carbon	Hydrogen	Hydrogen CCGT	Included	Hydrogen is a low or zero carbon (depending on production technology) alternative to natural gas. Hydrogen is expected to be blended into the natural gas network over the coming decades and is a viable fuel for future combined cycle gas turbine power plants.
	Waste	Waste	Included (existing only)	Existing 5MW plant included and is understood to be vital for the island's future waste management strategy. Model is constrained from adding new energy from waste plant – this is consistent with the island's waste management intentions.

SOURCE: ARUP ANALYSIS, BRITISH GEOLOGICAL SOCIETY AND TOWNROCK ENERGY

4.10 Modelling Methodology

Selected technologies and associated rationale (2/2)

B Generation technology options

The assessment of individual technologies was challenged and refined through a workshop with key stakeholders. Technologies that could support the island's transition, and the associated rationale, were also identified (2/2)

NOTE

- The multi-criteria assessment that informed evaluation of individual technologies.
- The evaluation takes into account the energy trilemma, the conditions and requirements on the island, and the challenges described on previous pages around intermittency, technology maturity, infrastructure requirements etc.

Category	Type	Sub-Type	Included or Excluded	Supporting rationale
Low Carbon	CCS	Thermal with CCS	Excluded	Technology is not yet proven to be commercially viable for deployment on large scale power plants. Also requires significant additional investment in transport and storage infrastructure, and policy incentives.
	Nuclear	Large scale Nuclear	Excluded	Not considered to be appropriate for the Isle of Man given the size of the population and overall demand. Also a significantly expensive technology compared to other intermittent renewables.
	Nuclear	SMRs	Excluded	Whilst small modular reactors (SMRs) can be deployed at small scale, the technology is still immature, and not proven to be deployable at commercial scale. Hence, excluded from the generation mix.
Fossil Fuel	Thermal	CCGT	Included (existing only)	Existing plant included in the model with a retirement date at the end of 2031 as confirmed by MUA. Existing operation is not constrained, other than by the proposed carbon budget.
	Thermal	CCGT (**Blended with hydrogen)	Excluded	Discussion between GE and MUA are understood to have concluded that significant investment will be required to upgrade the plant to accommodate natural gas blended with up to 30% hydrogen. Ability to accommodate a higher blend is unlikely due to current technological limitations for the turbines.
	Thermal	Gas Reciprocating Engines	Excluded	These technologies emit significant greenhouse gases and have therefore been omitted from future generation mix.
	Thermal	OCGT	Excluded	
	Thermal	Diesel	Included	Existing diesel plant is included in the generation mix with a retirement date at the end of 2027 as confirmed by MUA. Existing operation is not constrained, other by the proposed carbon budget. No new plant is built due to the emissions reduction requirements.

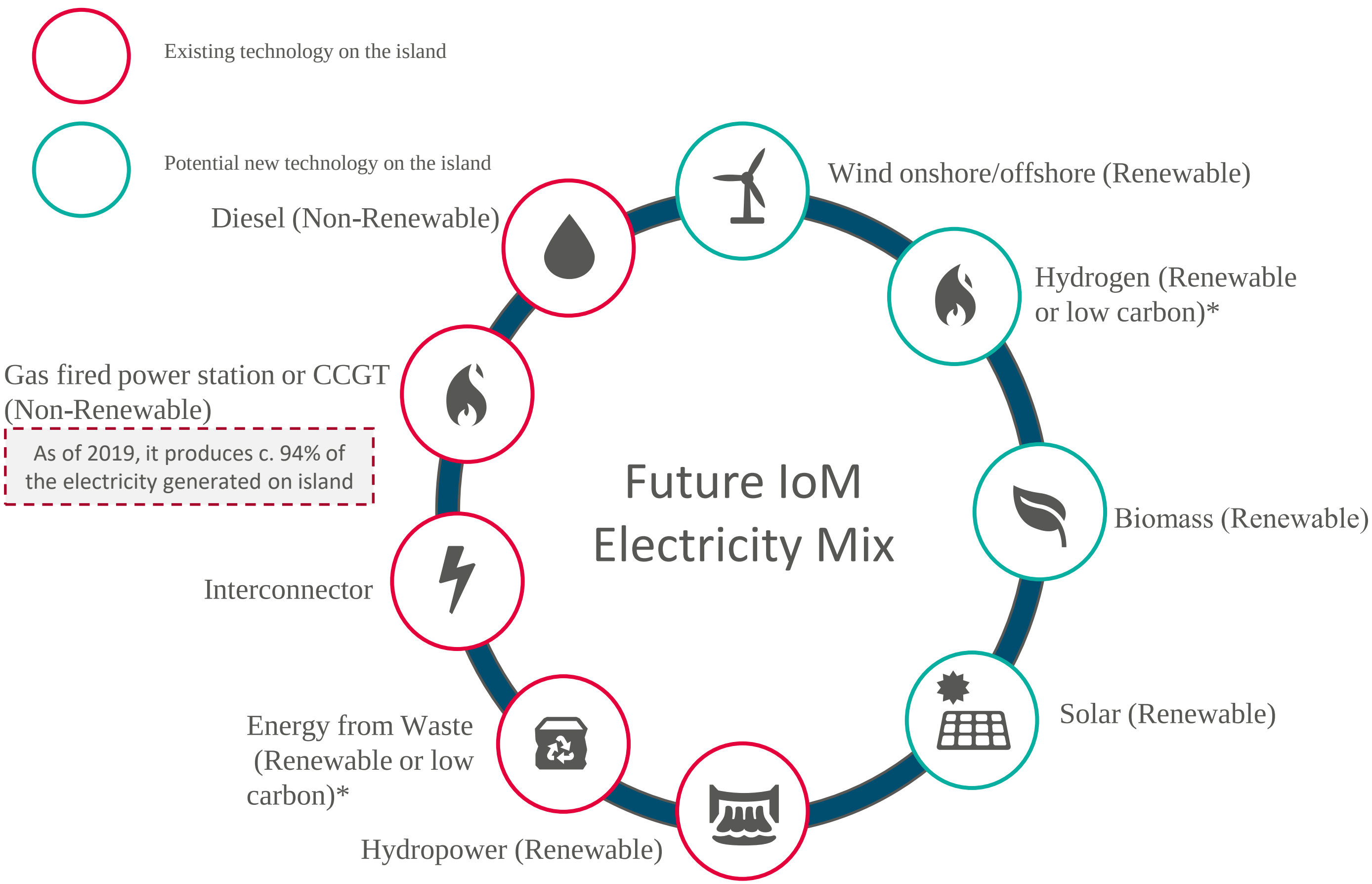
SOURCE: ARUP ANALYSIS, BRITISH GEOLOGICAL SOCIETY AND TOWNROCK ENERGY

B | Generation technology options

The island's transition is envisaged to include a portfolio of new intermittent renewables, biomass, interconnector and existing renewables. This final suite of technologies was modelled in Plexos.

NOTE

*EfW and Hydrogen-fuelled power plants can be either renewable (zero carbon) or low carbon depending on the biogenic content of the waste (for the EfW plant) and the method used for producing hydrogen and capturing residual emissions (if any).



SOURCE: ARUP ANALYSIS

B Generation technology options

Discussions with the IoM and the data received from the IoM indicates that the existing electricity system has N-2 capacity and N-2 grid operability resilience.

NOTE:

- **N-1/2 Capacity resilience definition:** where peak demand can by met if the single/two largest generators are removed.
- **N-1/2 grid operability resilience definition:** where the one/two provider(s) of grid supporting ancillary services are removed but the grid is still operable.
- *This is the installed capacity of the CCGT (2GTs at 30MW + 1 ST at 23 MW). IoM has confirmed that realistically the two gas turbines (GTs) operate at 27-30 MW when the ST is in service and the steam turbine (ST) at 20MW, due to inefficiencies. When the ST is shutdown, the GTs are limited to 20MW to protect the steam boilers. Without the interconnector the ST can't run meaning that the GTs are limited to 40MW and can only be ran up to 60MW if required in emergency situations. This limit would not apply if the ST is decommissioned.
- ** the diesel plants are actually comprised of individual c.10 MW generator units, however exemplified by a recent fire at the Peel Station in one of the units, resulted in all units being taken out of operation, so will be grouped together for this analysis.

NORMAL OPERATION

Interconnector	CCGT*	Pulrose Diesel Plant (PuD)**	Peel Diesel Plant**	EfW	Hydro	**Total**	**Maximum peak demand since 2010**	**Excess capacity**
60MW	83*MW	50MW	40MW	5MW	1MW	239MW	91MW	149MW

N-2 CAPACITY RESILIENCE TEST

Fault type	Interconnector	CCGT*	Pulrose Diesel Plant(PuD)**	Peel Diesel Plant**	EfW	Hydro	**Total**	**Maximum peak demand since 2010**	**Excess capacity**
N-2 (I/C + CCGT)	0MW	0MW	50MW	40MW	5	1MW	96MW	91MW	5MW

- N-2 means peak demand can still be met if two largest generators are removed. On the IoM the two largest generators are the interconnector and the CCGT.
- As highlighted above with these two generators taken offline and the CCGT the IoM still has N-2 in capacity terms.

N-2 GRID OPERABILITY TEST

	Interconnector	CCGT	Pulrose Diesel Plant(PuD)**	Peel Diesel Plant**	EfW	Hydro
Contributes to ancillary service provision?	✓	✓	✓	✓	○	○

Fault type	Interconnector	CCGT	Pulrose Diesel Plant(PuD)**	Peel Diesel Plant**	EfW	Hydro
N-2 (I/C + CCGT)	X	X	✓	✓	○	○

- Ancillary services such as inertia provision and frequency response are integral to ensure the IoM grid stays operable.
- As highlighted in the table above if the CCGT and interconnector went out of operation the grid could still operate. Therefore the IoM has N-2 grid operability resilience.

SOURCE: MUA AND ARUP ANALYSIS

Electricity system resilience examples from other Island jurisdictions

B Generation technology options

Publicly available information suggests that the Isle of Man has higher resilience requirements compared to other similar island jurisdictions.

	Resilience standard
Gibraltar The electricity has historically been dependent on 40 diesel generators, totalling 60MW, however the recent decommissioning of the Waterport Power Station, has reduced this capacity to 45MW. In 2019 a new 80MW LNG power station was built. Gibraltar is currently not connected to any other countries' electricity system.. Peak electricity demand was c.44MW in 2019. It appears Gibraltar narrowly achieve N-1 capacity resilience, however the grid operability resilience is probably lower.	N-1
Singapore Currently Singapore provides 95% of electricity from imported natural gas used in CCGTs, some municipal waste, biomass, solar and other fossil fuels. Singapore is connected to Malaysia via 200MW AC line. Singapore had a peak demand of 7.4 GW in May 2019, but had 12.6 GW of installed capacity split across numerous plants. Singapore's installed capacity is distributed across many power plants rather than focused at very few, improving security of supply. In Singapore the minimum reserve requirement is based on a three hour loss of load expectation (LoLE) per year requirement. In reality, Singapore's two largest power stations have a combined capacity of c.4.7 GW, so loosing them Singapore can still serve peak demand and therefore Singapore has N-2. Importantly, Singapore may currently have N-2, but its resilience minimum standard is LoLE suggesting as fossil fuel's phase out this will be its target, rather than the more expensive N-2.	LoLE
Malta Connected to Italy via 200 MW AC interconnector, Malta is a net importer. Malta imported c.25% of its electricity in 2019. On island Malta has c.538 MW of installed capacity mainly gas CCGT and heavy oil at the Delimara Power Station complex (two largest plants are 205MW and 153MW). Malta has a peak demand c.390MW. ENTSO-E reported in 2015 that Malta has no resilience standard; however, based on capacities presented, Malta probably has N-1. Other than the interconnector, this is all fossil fuel based though, which will not be viable in the future.	None
Cyprus Cyprus has an installed CCGT and oil fired capacity of approximately 1,480MW split between three power stations and some small renewable capacity. Cyprus has a reserve margin of 20% higher than the peak demand as their electricity standard.	Reserve margin
Channel Islands **Guernsey** currently has fossil fuel based power stations totalling approximately 1,15MW of capacity and a 60MW interconnector cable to Jersey. Peak demand on the Island is c.90MW. The island currently has a N-2 capacity redundancy policy, but would be vulnerable in terms of keeping the grid operable if the interconnector to Jersey was lost. Guernsey plans to reduce this N-2 capacity redundancy policy to a lower level (e.g., N-1) pending the approval of the new 100MW GF-1 interconnector cable direct to France. **Jersey** has three interconnectors to France and one to Guernsey, totalling 190MW of interconnector capacity, with c.200MW fossil fuel power station and EfW installed on the island. The island's historical peak demand is c.150 MW. Jersey operates under a 'adapted N-1' standard (as of 2016)**.	N-1/2

*New Power Plant North Mole Gibraltar: Example of CO2 footprint improvement with Gas and Dual Fuel engines. Hans Jörg Lauer. MAN Diesel & Turbo SE, Stadtbachstrasse 1, Augsburg, Germany

**Jersey Electricity's 'adapted N-1' security standard defined:

- A one-in-eight year winter peak demand.
- All normal load in the event of the loss of the single largest interconnector with France (N minus 1) plus a simultaneous failure of the largest: Diesel generator; and Gas turbine.
- 75% of peak winter load for 48 hours from on-Island generation (no simultaneous loss of on-Island capacity).
- No coincidence of the above

LNG- Liquified Natural Gas

HM GOVERNMENT OF GIBRALTAR, PEI, ENGAIN*, EMA, IEA, ARUP ANALYSIS, NATIONAL STATISTICS POLICY MALTA, GUERNSEY PRES, JERSEY ELECTRICITY

B Generation technology options

E Fuel constraints

The future energy scenarios have been developed with minimum N-1 level of resilience. Technologies that provide this resilience need to be dispatchable and carbon neutral, thereby narrowing the options to biomass and interconnector.

NOTE

*Biomass has been used for the purpose of this modelling exercise and as agreed with the IoM Climate Change Transformation Team. However, biomass fuel could potentially be replaced with another carbon neutral biofuel or biomaterial (e.g., biogas or biodiesel).

Key IoM-specific inputs

- The electricity system needs to have a **minimum N-1 resilience level in scenarios 1-3 and N-2 resilience level in scenario 4**. This ensures that if largest generator is unavailable for unforeseen reasons, then the peak demand can still be met.
- The resilience requirement needs to be fulfilled by technology that is **carbon neutral** – this is essential to meet emission reduction targets.
- **Offsetting** emissions against other jurisdictions is **not considered permissible** in this instance.
- The technology also needs to be **dispatchable**. The dispatchability needs to be sustainable over a long period – for instance, if an interconnector was to be damaged, the dispatchable power plant needs to be able to operate over a sustained period to provide resilience and meet peak demand, until the interconnector is fully repaired.
- **Biomass* and interconnector** were therefore identified as the most suitable carbon neutral and dispatchable technologies to meet the resilience requirements.
- Fuel for dispatchable power plants on the island would need to be sourced from the island. IoM has estimated that it can supply up to **30kT of biomass per annum**. Consequently, the operation of the biomass plant needs to be limited by the available quantity of fuel.
- IoM **does not intend to import biomass** from other jurisdictions in order to avoid further emissions. However, in emergency scenarios, some imports may be necessary.
- A **minimum 140MW of interconnector capacity** included in all scenarios by 2040. At least two interconnectors in two out of the four scenarios.
- Based on the data received from the IoM, the **build cost** for technologies **on the IoM** are understood to be approximately **11% higher than the GB**. These higher costs are reflected in the economic modelling of the scenarios.

SOURCE: IOM; ARUP ANALYSIS

B Generation technology options

E Fuel constraints

The key constraints and the short list of technologies described previously have informed the assumptions and inputs for the four scenarios modelled by Arup.

*Biomass has been used for the purpose of this modelling exercise and as agreed with the IoM Climate Change Transformation Team. However, biomass fuel could potentially be replaced with another carbon neutral biofuel (e.g., biogas or biodiesel).

**The CCGT asset life could potentially be extended further, but would require refurbishment at a cost.

Peaking: the occasional running of a plant to meet periods of high peak demand.

RENEWABLES OR LOW CARBON TECHNOLOGIES

Technology	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Interconnector	**1 x interconnector** **Existing** 60 MW AC reaches end of life at end of 2040 (based on information provided by MUA). **Existing** AC interconnected is replaced with a 140 MW DC interconnector after retirement	**2 x interconnectors** **New 140 MW DC** interconnector comes online in 2028. **Existing** 60 MW AC interconnector reaches end of life in 2040 (based on information provided by MUA). **Existing** replaced with another 140 MW DC interconnector.	**2 x interconnectors** **New 140 MW DC** interconnector comes online in 2028. **Existing** 60MW AC extended at least till 2050. (this will require upgrades and potential commercial and contractual negotiations).	**4 x interconnectors in total** **3 x New 70 MW DC** interconnectors come online between 2028 and 2032. **Existing** 60MW AC extended at least till 2050. (this will require upgrades and potential commercial and contractual negotiations).
Offshore Wind	Model decision	Model decision	Model decision	Model decision
Onshore Wind	Model decision	Model decision	Model decision	Model decision
Solar PV	Model decision	Model decision	Model decision. 50% of new residential, commercial and industrial customers assumed to install behind-the-meter solar PV.	Model decision. 50% of new and existing residential, commercial and industrial customers assumed to install behind-the-meter solar PV.
Biomass*	Biomass built to ensure N-1 resilience in capacity terms, but will operate as a peaking plant due to fuel constraints and interconnection being available for generation.	Biomass built to ensure N-1 resilience in capacity terms, but will operate as a peaking plant due to fuel constraints and interconnection being available for generation.	Biomass built to ensure N-1 resilience in capacity terms, but will operate as a peaking plant due to fuel constraints and interconnection being available for generation.	No biomass
Hydrogen CCGT	Model decision	Model decision	Model decision	Model decision
Hydropower	No capacity expansion possible	No capacity expansion possible	No capacity expansion possible	No capacity expansion possible
EfW	No capacity expansion possible	No capacity expansion possible	No capacity expansion possible	No capacity expansion possible
CCGT	Can't increase beyond existing capacity. Reaches end of asset life by 2031 (based on information provided by MUA). **	Can't increase beyond existing capacity. Reaches end of asset life by 2031 (based on information provided by MUA). **	Can't increase beyond existing capacity. Reaches end of asset life by 2031 (based on information provided by MUA). **	Can't increase beyond existing capacity. Reaches end of asset life by 2031 (based on information provided by MUA). **
Diesel	Can't increase beyond existing capacity. Reaches end of asset life by 2027 (based on information provided by MUA).	Can't increase beyond existing capacity. Reaches end of asset life by 2027 (based on information provided by MUA).	Can't increase beyond existing capacity. Reaches end of asset life by 2027 (based on information provided by MUA).	Can't increase beyond existing capacity. Reaches end of asset life by 2027 (based on information provided by MUA).

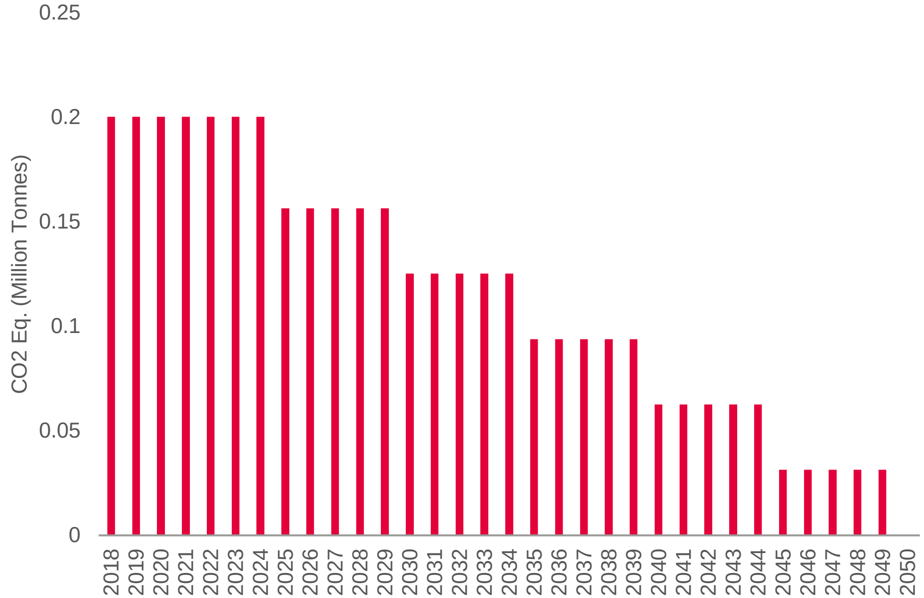
In the absence of a carbon budget, an emissions reduction profile, specific to the electricity generation sector, has also been developed to guide the evolution of the future energy scenarios.

NOTE

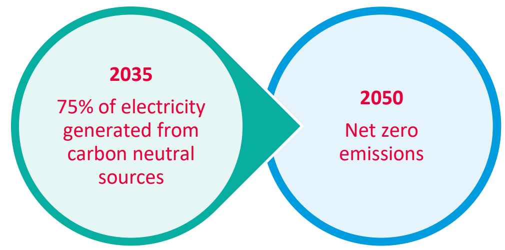
Co2 Eq. emission level refers to the fact that all greenhouse gases (GHG) emitted by the power system have been converted in a single unit. The model takes into account the following GHG:

- CH4
- N2O
- Co2

CO2 EQUIVALENT EMISSIONS TRAJECTORY (2018A – 2050F) (MILLION TONNES)



EMISSION REDUCTION TARGETS FOR IOM



SOURCE: ARUP ANALYSIS

- The evolution of future energy generation scenarios needs to meet emission reduction targets. Whilst the IoM's Climate Bill sets a target to reach net zero emissions by 2050, there are no emissions-related targets set for intermediate years.
- Through discussions with the IoM stakeholders, Arup developed a stepped profile for emissions reduction for the purposes of modelling.
- The first stepped reduction is assumed to take place in 2025. This reflects a c.5-year period from the commencement of this study, to the implementation of the first set of alternative generating technologies (e.g., solar PV or onshore / offshore wind). Subsequent reductions also take place on a five-year basis. This five year reduction profile enables sufficient time from project planning to execution and commissioning.
- It should be noted that accurate historical emissions data for electricity generation is only available for 2018. Data for all other years is currently undergoing review and correction by IoM. It is understood that 2019 and 2020 are likely to be higher than 2018 emissions, as the island exported more electricity to the UK from the CCGT plant than it did in 2018.
- It is important to note that the only emissions target in the IoM legislation is net zero emissions by 2050. The 2035 target of 75% electricity generation from renewable or carbon neutral sources, although it will help reduce emissions, is not a fixed carbon emissions target.
- Whilst a stepped profile has been developed for the purpose of this study, it is acknowledged that alternative emissions reduction profiles can be introduced to enable certain investment decision to be delayed.

F Operational and capital costs per generation technology

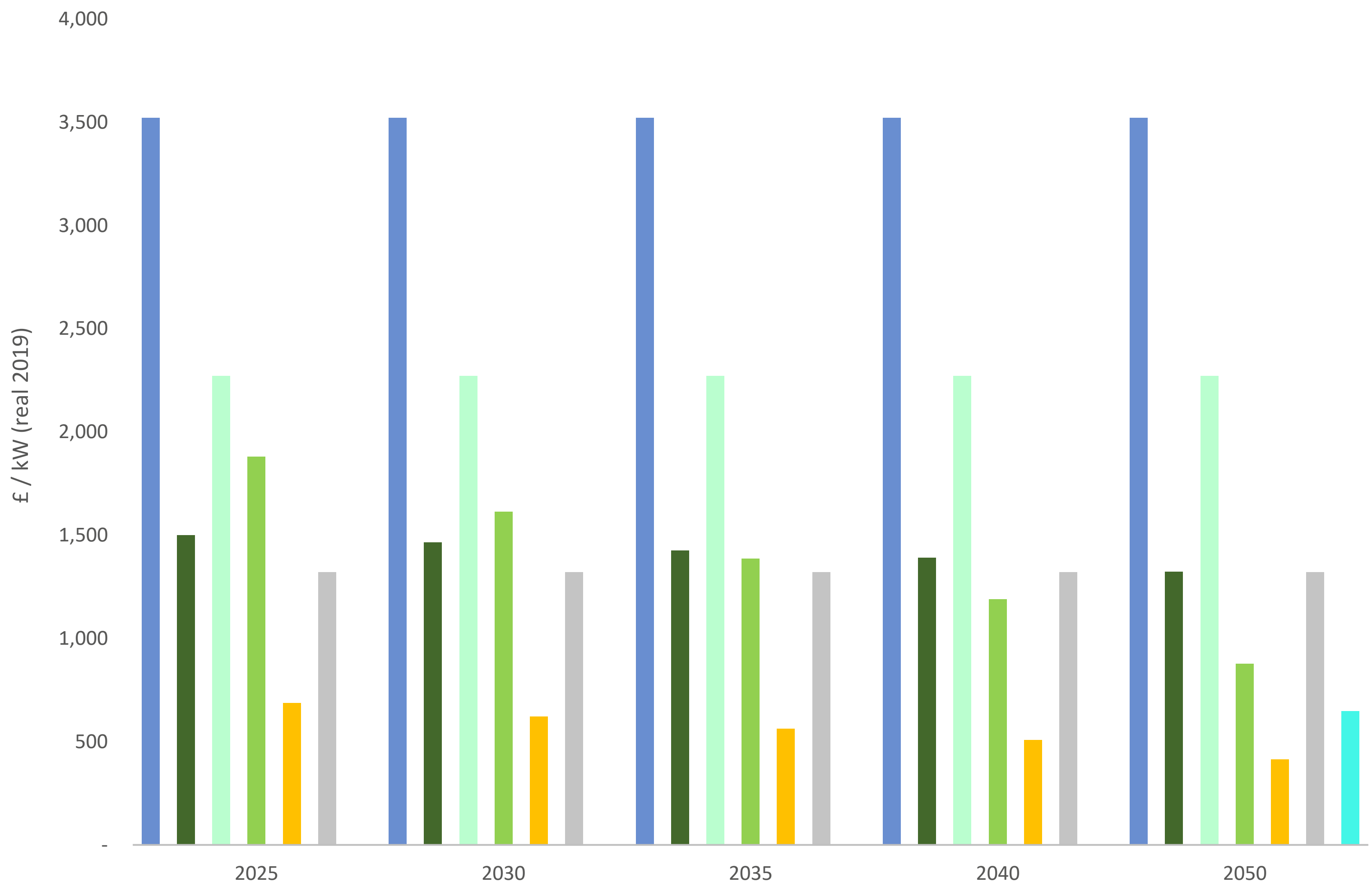
In terms of capex, offshore wind sees the largest improvements, while solar PV (undistributed) and onshore wind see moderate reductions. No improvments expected for other technologies.

LEGEND

- ONSHORE WIND (>1MW)
- ONSHORE WIND (<1MW)
- OFFSHORE WIND
- BIOMASS
- HYDROGEN CCGT
- SOLAR (UNDISTRIBUTED)
- SOLAR (DISTRIBUTED)

Hydrogen is competitive on capex terms against other renewable technologies, however when assessed on a total LCoE basis the fuel and carbon components make it much less competitive, additionally hydrogen only displayed in 2050, as blended quantities not high enough in GB grid until late post 2045, however this date could be earlier or later depending on how this technology develops.

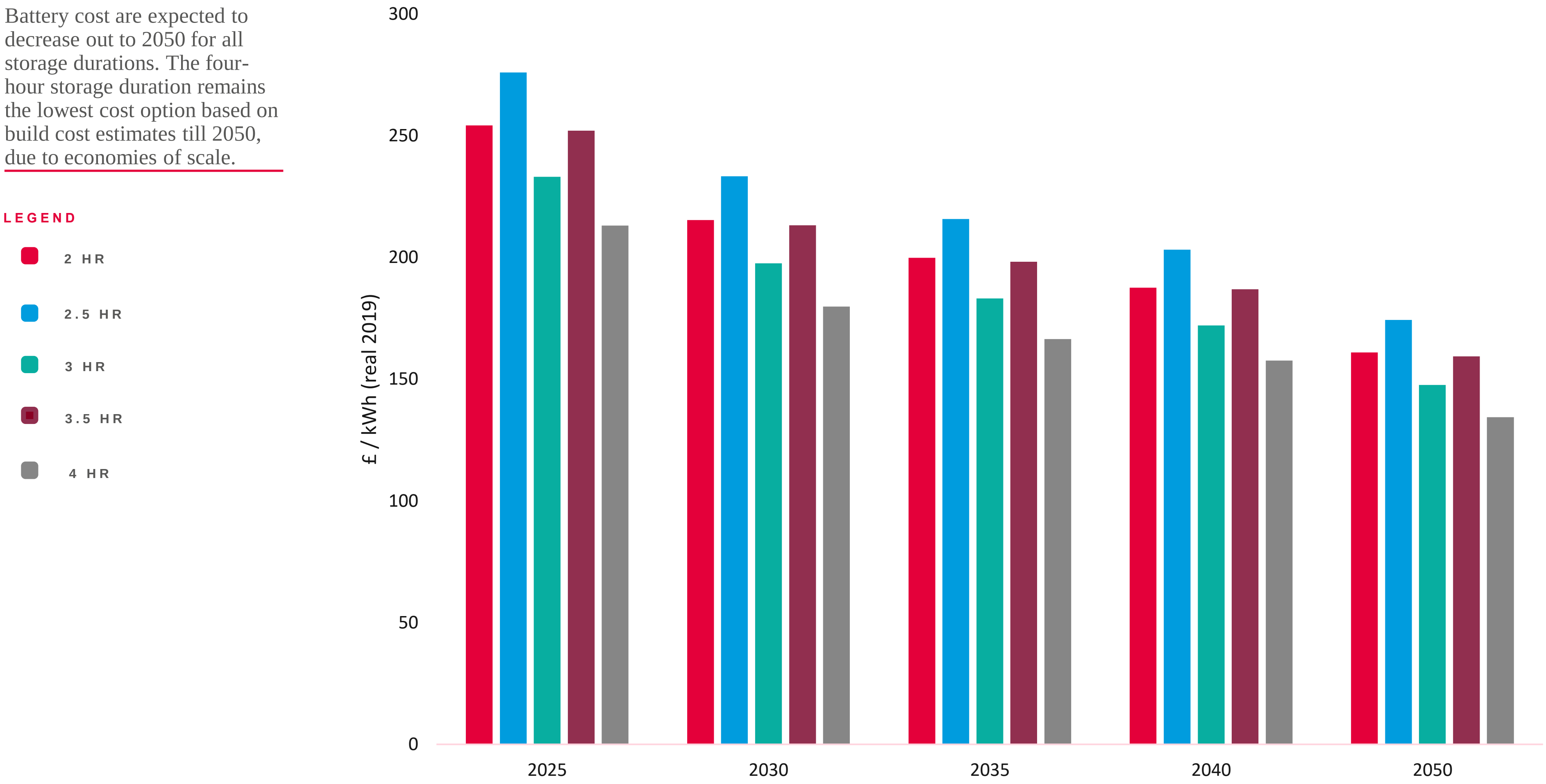
Capex: includes pre-development and build cost.



SOURCE: BEIS AND ARUP ANALYSIS

F Operational and capital costs per generation technology

Battery cost are expected to decrease out to 2050 for all storage durations. The four-hour storage duration remains the lowest cost option based on build cost estimates till 2050, due to economies of scale.

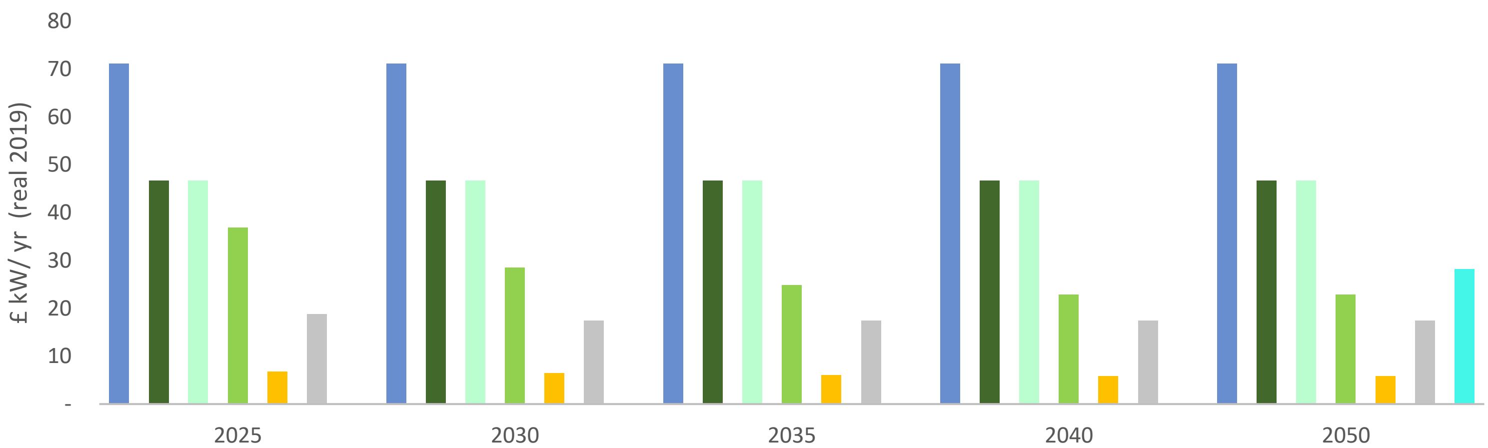


SOURCE: NREL 2018 US UTILITY SCALE PHOTOVOLTAICS PLUS ENERGY STORAGE SYSTEM COSTS BENCHMARK (FOR 2018 COSTS), NREL COST PROJECTIONS FOR UTILITY-SCALE BATTERY STORAGE (FOR LEARNING RATES)

F Operational and capital costs per generation technology

Other than offshore wind and solar PV, renewable technologies see no improvement in terms of fixed and variable operational and maintenance cost between now and 2050, according to BEIS.

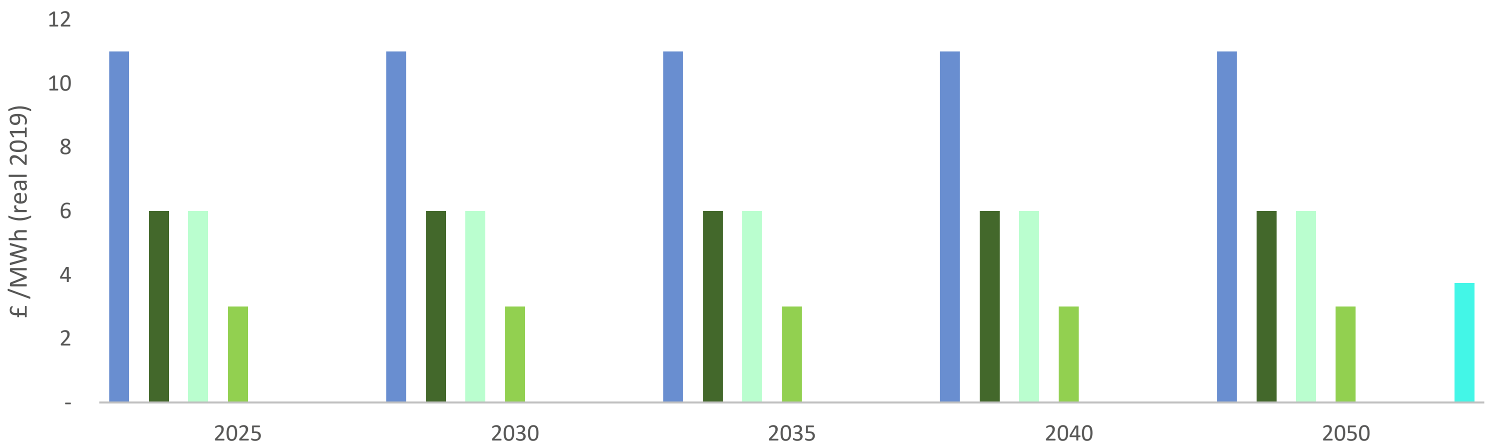
EVOLUTION OF FIXED OPERATIONAL & MAINTENANCE COSTS



LEGEND

- ONSHORE WIND (>1MW)
- ONSHORE WIND (<1MW)
- OFFSHORE WIND
- BIOMASS
- HYDROGEN CCGT
- SOLAR (UNDISTRIBUTED)
- SOLAR (DISTRIBUTED)

EVOLUTION OF VARIABLE OPERATIONAL & MAINTENANCE COSTS



Hydrogen is competitive on opex terms against other renewable technologies, however when assessed on a total LCoE basis the fuel and carbon components make it much less competitive, additionally hydrogen only displayed in 2050, as blended hydrogen quantities not high enough in GB grid until late post 2045, however this date could be earlier or later depending on how this technology develops.

Note: There are no variable O&M costs associated with solar generation.

SOURCE: BEIS

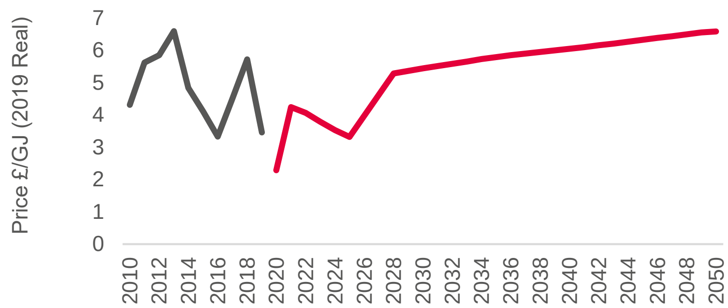
Modelling Methodology

Commodity prices

G | Fuel prices

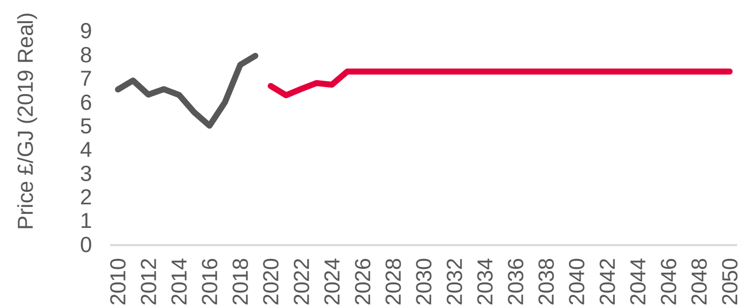
Commodity prices are one of the key inputs in Arup's model. Natural gas is expected to retain its prominence in the UK energy market. While there are limited market views on the future price of biomass, there are diverging views for future prices of gasoil and fuel oil. Green hydrogen is expected to lower the cost differential with blue hydrogen as these new technologies evolve.

NATURAL GAS PRICE EVOLUTION*



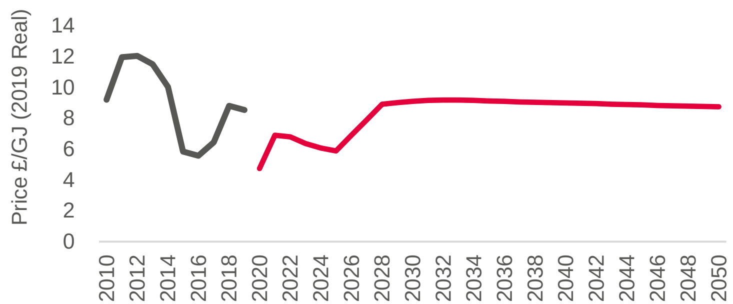
In the short term, our forecast is based on the historical forward curve, as it reflects all current information of players on the gas market. Our longer term forecasts are based on DECC and IEA views on future natural gas price development. By 2030, gas prices are set by the long run marginal cost of US LNG. Interpolation is used to create the price curve between long and short term.

WOOD PELLETS PRICE EVOLUTION



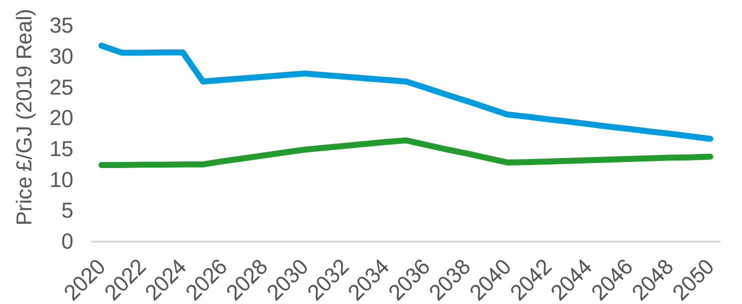
Arup used the 'forward curve' and extrapolated this to forecast the price of biomass up to 2050. We expect the influence of biomass to become more significant in the post-subsidy period (i.e., beyond 2028) when the commodity will be traded purely based on market dynamics.

BRENT CRUDE PRICE EVOLUTION



Our analysis indicates a strong historical correlation between the Brent crude price and the price of gasoil and fuel oil. To estimate the future price of gasoil and fuel oil, we have taken a combination of the forward curve and the National Grid ESO central forecasts for the Brent crude price.

HYDROGEN PRICE EVOLUTION



Arup's hydrogen price forecast is based on projected future hydrogen production costs in the UK and Europe in 5 yearly intervals, sampled from a number of sources. Arup has interpolated the results between the 5 year periods. Costs are currently very uncertain, and depend on a number of factors.

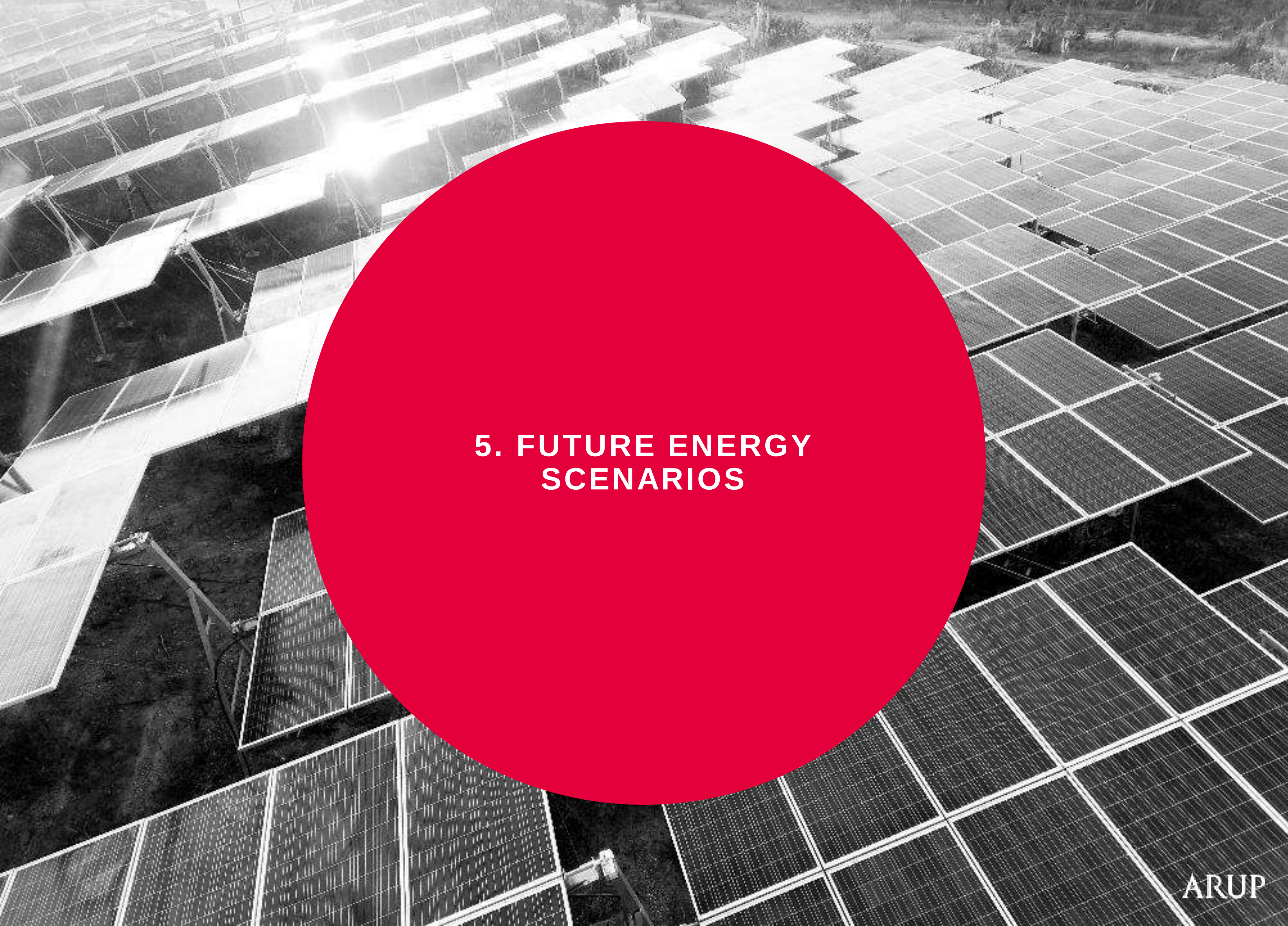
LEGEND

- Historical
- Central Forecast
- Blue Hydrogen
- Green Hydrogen

* The natural gas price when inputted into the electricity system model as a fuel cost for the CCGT has a 10% uplift applied to factor in local IoM cost inputs.

SOURCES: NATIONAL GRID ESO, BEIS, ICE NATURAL GAS FUTURES AND FES 2020 REPORT, ARGUS MEDIA FUTURES AND ARUP ANALYSIS

5. FUTURE ENERGY SCENARIOS



Future Energy Scenarios

Electricity capacity mixes for Net Zero greenhouse gas emission scenarios

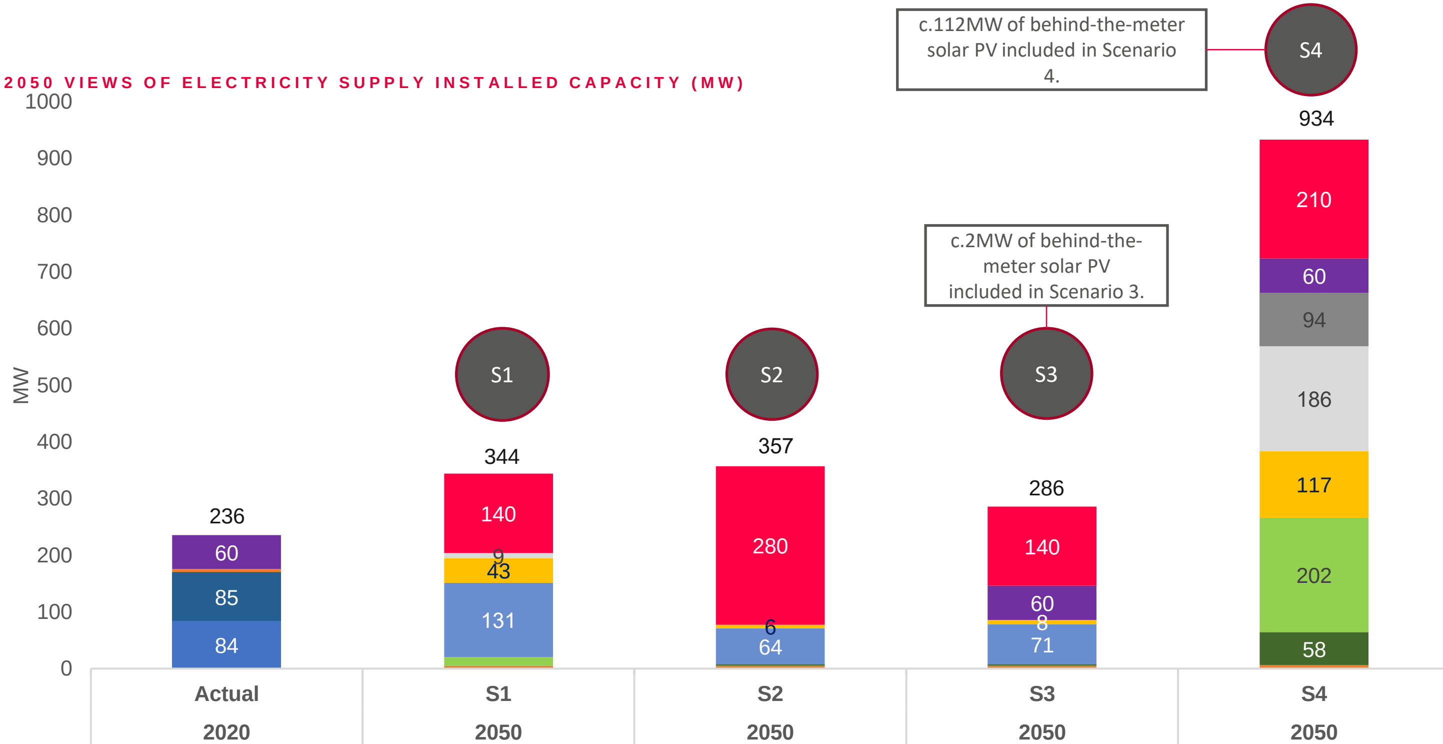
The number, size and installation/phase out timing of interconnectors has a significant impact on installed island generation capacity to meet N-1 resilience for S1-S3 and N-2 resilience for S4.

LEGEND

- CCGT
- DIESEL
- HYDROPOWER
- ENERGY FROM WASTE (EFW)
- ONSHORE WIND
- BIOMASS*
- SOLAR
- ENERGY STORAGE (PUMPED SEAWATER)
- ENERGY STORAGE (BATTERIES)
- OFFSHORE WIND
- INTERCONNECTOR (EXISTING)
- INTERCONNECTOR (NEW)

*Biomass could potentially be replaced with another carbon neutral biofuel (e.g., biogas or biodiesel).

Biomass is a renewable technology, meaning there is a significant quantity renewable generation built in all scenarios.



- **Scenario 1:** This scenario has a single 140 MW interconnector and consequently the highest amount of biomass installed capacity required to provide N-1 resilience.
- **Scenario 2:** Includes two large interconnectors, and the largest interconnection capacity out of all four scenarios. This explains why it has the smallest installed on-island generation capacity. The 64MW of installed biomass capacity is built before the second new interconnector is installed in 2041 to provide N-1 resilience and is therefore fairly non-contributary in generation terms by 2050.
- **Scenario 3:** Has the smallest total installed capacity. This scenario maintains its existing 60 MW AC interconnector until at least 2050 (this will require upgrades and potential commercial and contractual negotiations). Hence, it requires less on-island capacity to be built than S1. Additionally, it has less total installed capacity required to ensure the resilience requirement than S2 – this is again due to the existing interconnector.
- **Scenario 4:** Has the largest total installed capacity out of all scenarios in 2050. This increased capacity is a result of greater on-island generation driven by offshore wind (210 MW) and behind-the-meter solar generation (112 MW), alongside sufficient interconnector capacity to ensure N-2 resilience through four separate cables. The existing 60 MW interconnector is assumed to be retained at least until 2050 (similar to scenario 3).
- It should be noted that across all three scenarios, the installed capacities of interconnector and biomass could be split across multiple plants. For instance, in S1, 2 x 70MW interconnectors could be built to achieve 140 MW of total interconnector capacity, or multiple biomass plants could be built totalling to 131 MW of installed capacity This would further improve the resilience of the system , since a smaller amount of installed capacity would be affected by a fault at a single plant. However, splitting the generation across multiple plants will also result in increased capital cost.

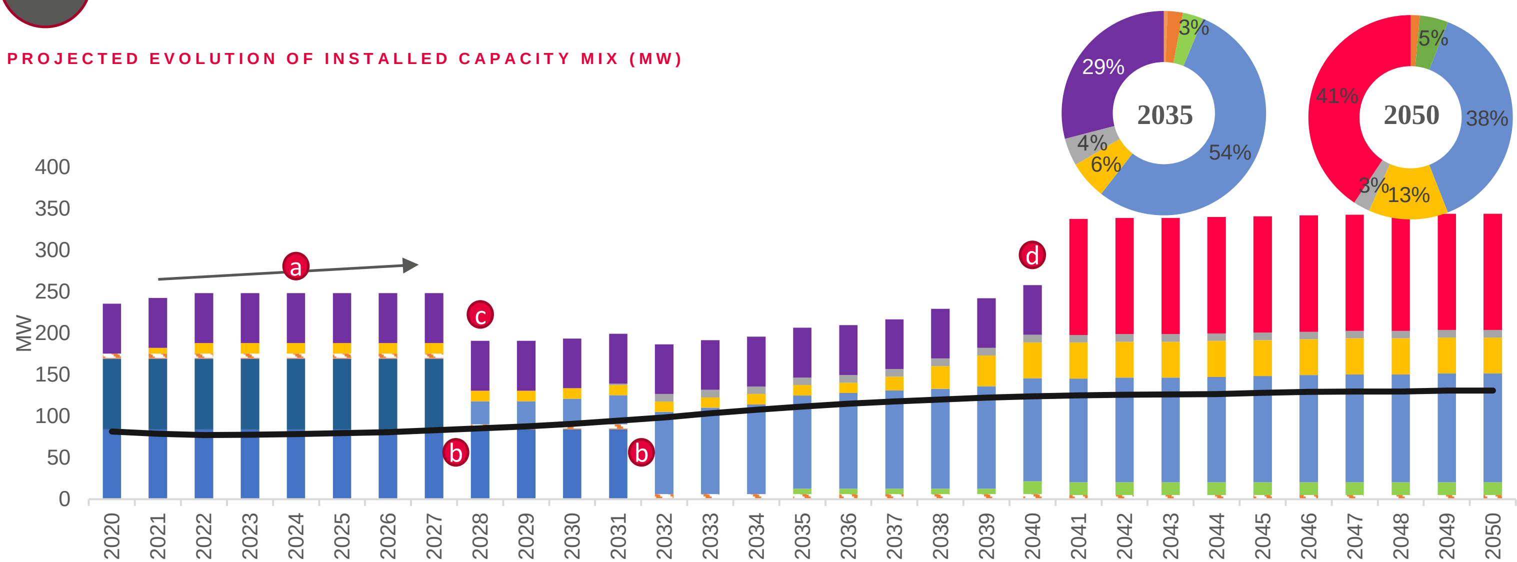
Future Energy Scenarios

Installed capacity(MW): Scenario 1

S1

Scenario 1 has nearly 60% on-island renewable capacity, including biomass, by 2050. Whilst there is significant biomass capacity in this scenario, the generation from this plant is projected to reduce over time.

PROJECTED EVOLUTION OF INSTALLED CAPACITY MIX (MW)



SOURCE: ARUP ANALYSIS

LEGEND

- CCGT
- DIESEL
- HYDROPOWER
- ENERGY FROM WASTE (EFW)
- ONSHORE WIND
- BIOMASS*
- SOLAR
- ENERGY STORAGE
- OFFSHORE WIND
- INTERCONNECTOR (EXISTING)
- INTERCONNECTOR (NEW)
- PEAK DEMAND (CT)

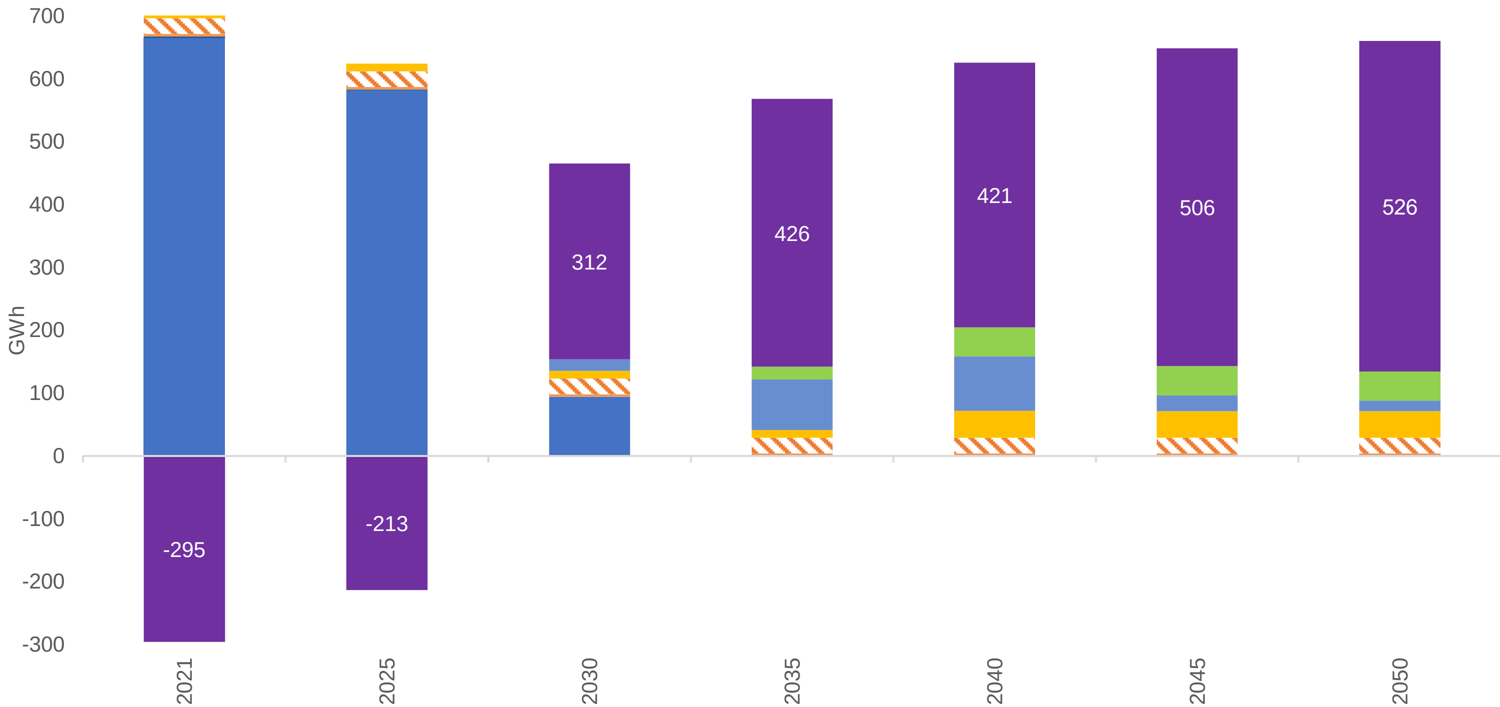
*Biomass could potentially be replaced with another carbon neutral biofuel (e.g., biogas or biodiesel).

KEY OUTCOMES

- a **13 MW of solar** capacity operational **by 2022**. This is driven by an uptick in demand from 2022 and the requirement to not emit more GHG than the 2018 baseline. Consequently, the model builds renewable capacity to compensate for not being able to generate additional electricity from existing fossil-fuel based plants.
- b Existing **diesels** and **CCGT** cease operation by end of **2027** and **2031**, respectively.
- b **Biomass** becomes operational following the retirement of the diesels and CCGT to **maintain** the **resilience level**. Biomass becomes the second largest generator after interconnection, once both the CCGT and the diesel plants are retired. **However, there could be commercial benefits if the CCGT was only partly decommissioned and ran in OCGT mode or refurbished (at a cost) to run for longer – this is subject to the amount of hydrogen blended in the gas network in the future, and its compatibility with the existing plant.** Diesels however can't be extended past 2027 as advised by MUA due to issues with the fuel lines. Other than biomass small amounts of solar and offshore wind are built increasingly from 2035.
- c **Installed renewable generation** on the IoM doesn't reach **20MW** until **2028**. IoM originally had an ambition to meet 20MW installed capacity target by 2025.
- d **Existing 60 MW** AC interconnector reaches end of life by **2040.** This will be replaced by a new 140 MW DC interconnector (in operational terms) by start of 2041.
- Interconnection make up **29%** of installed capacity by **2035** and **41%** by **2050.**
- N-1 resilience 'on paper' is provided from 2028-32, but in practice it is not as the CCGT can't operate at full capacity when the interconnector is down. This fact was only confirmed by IoM after modelling was completed. Installing some of the biomass earlier would mitigate this.
- **Build up is shown linearly due to the highly granular nature of the model. This allows flexibility in decision making and planning the installed capacity build out. In reality development of new generation would typically be phased into 5+ year blocks rather than annual increases.**

Scenario 1 has approximately 20% on-island generation, enabled by a combination of biomass, solar PV and offshore wind.

PROJECTED EVOLUTION OF GENERATION MIX (GWH)



LEGEND

- CCGT
- DIESEL
- HYDROPOWER
- ENERGY FROM WASTE (EFW)
- ONSHORE WIND
- BIOMASS*
- SOLAR
- OFFSHORE WIND
- GB TO IOM

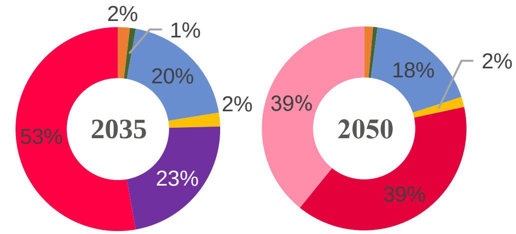
*Biomass could potentially be replaced with another carbon neutral biofuel (e.g., biogas or biodiesel).

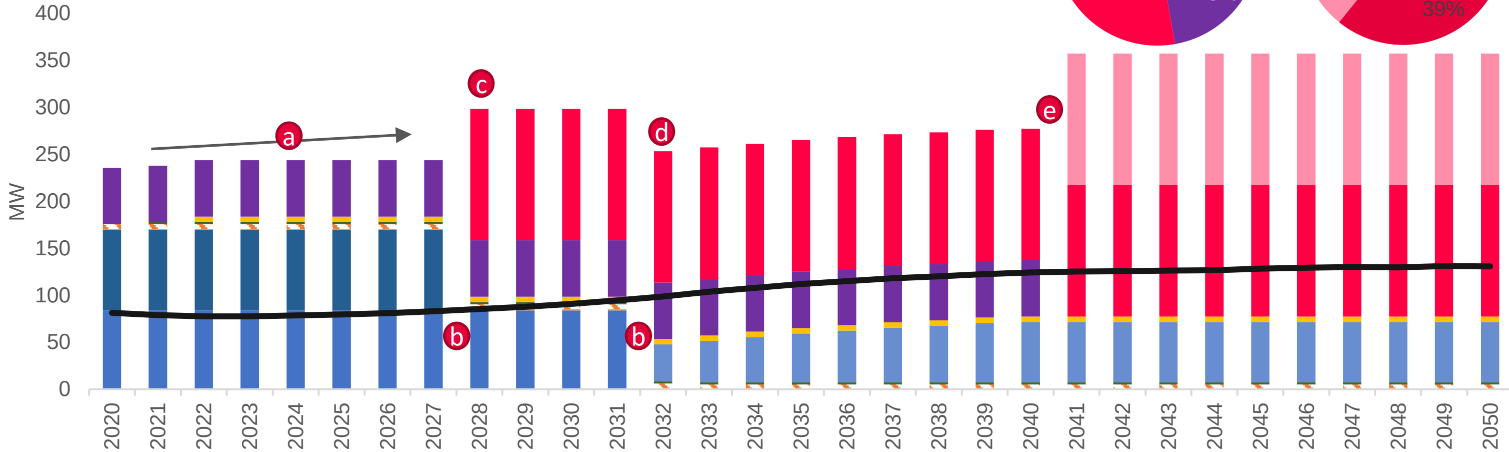
- The IoM goes from a **net exporter** to a **net importer** of power by 2050.
- Biomass could be imported if required in periods where generation required from biomass is more than the island can produce in terms of fuel, it can also be stored in years where it is not required for years when it is.
- It should be noted that the generation from biomass declines over the forecast horizon. This trend suggests a potential opportunity to further optimise the installed capacity mix by brining forward the operation of the proposed new interconnector. This will negate or reduce the need for biomass and the associated capital and fuel expenditure.
- The generation from the EfW plant is assumed to remain constant over the forecast horizon. This requires validating through the development of a waste strategy, particularly since the plant is currently only operating at c.60% capacity and waste volumes may decline in the future with the wider circular economy and net zero transition. This may have implications for the on-island generation mix.

SOURCE: ARUP ANALYSIS

Scenario 2 has approximately 20% on-island renewable capacity, including biomass, by 2050. The presence of two interconnectors in this scenario provides comparatively greater resilience and significantly reduced reliance on biomass.

PROJECTED EVOLUTION OF INSTALLED CAPACITY MIX (MW)





SOURCE: ARUP ANALYSIS

LEGEND

- CCGT
- DIESEL
- HYDROPOWER
- ENERGY FROM WASTE (EFW)
- ONSHORE WIND
- BIOMASS*
- SOLAR
- ENERGY STORAGE
- OFFSHORE WIND
- INTERCONNECTOR (EXISTING)
- INTERCONNECTOR (NEW 1)
- INTERCONNECTOR (NEW 2)
- PEAK DEMAND (CT)

KEY OUTCOMES

- a **2MW** of **onshore wind** built **in 2021** and **6MW** of **solar** in **2022.** This is driven by the uptick in demand from 2022 onwards and the cap on emissions. It is acknowledged that it will not be realistic to build these intermittent renewables by 2022, and hence the capacity expansion will need to be slightly delayed.
- b Existing **diesels** and **CCGT** cease operation by end of **2027** and **2031**.
- c Following the retirement of the existing diesels a new **140 MW DC** interconnector becomes operational by start of **2028** to maintain the resilience level. **Biomass** becomes operational to maintain resilience when the **CCGT retires** by the end of **2031. However, there could be commercial benefits if the CCGT was only partly decommissioned and ran in OCGT mode or refurbished (at a cost) to run for longer – this is subject to the amount of hydrogen blended in the gas network in the future, and its compatibility with the existing plant.** Diesels however can't be extended past 2027 as advised by MUA due to issues with the fuel lines.
- d **Installed renewable generation** on the IoM doesn't reach **20MW** until **2032**.. IoM originally had an ambition to meet 20MW installed capacity target by 2025.
- e **Existing 60 MW** AC interconnector reaches **end of life** by end of **2040.** This will be replaced by a **new 140 MW DC** interconnector by **start** of **2041.**
- Interconnection make up **76%** of installed capacity by **2035** and **78%** by **2050.**

*Biomass could potentially be replaced with another carbon neutral biofuel or biomaterial (e.g., biogas or biodiesel).

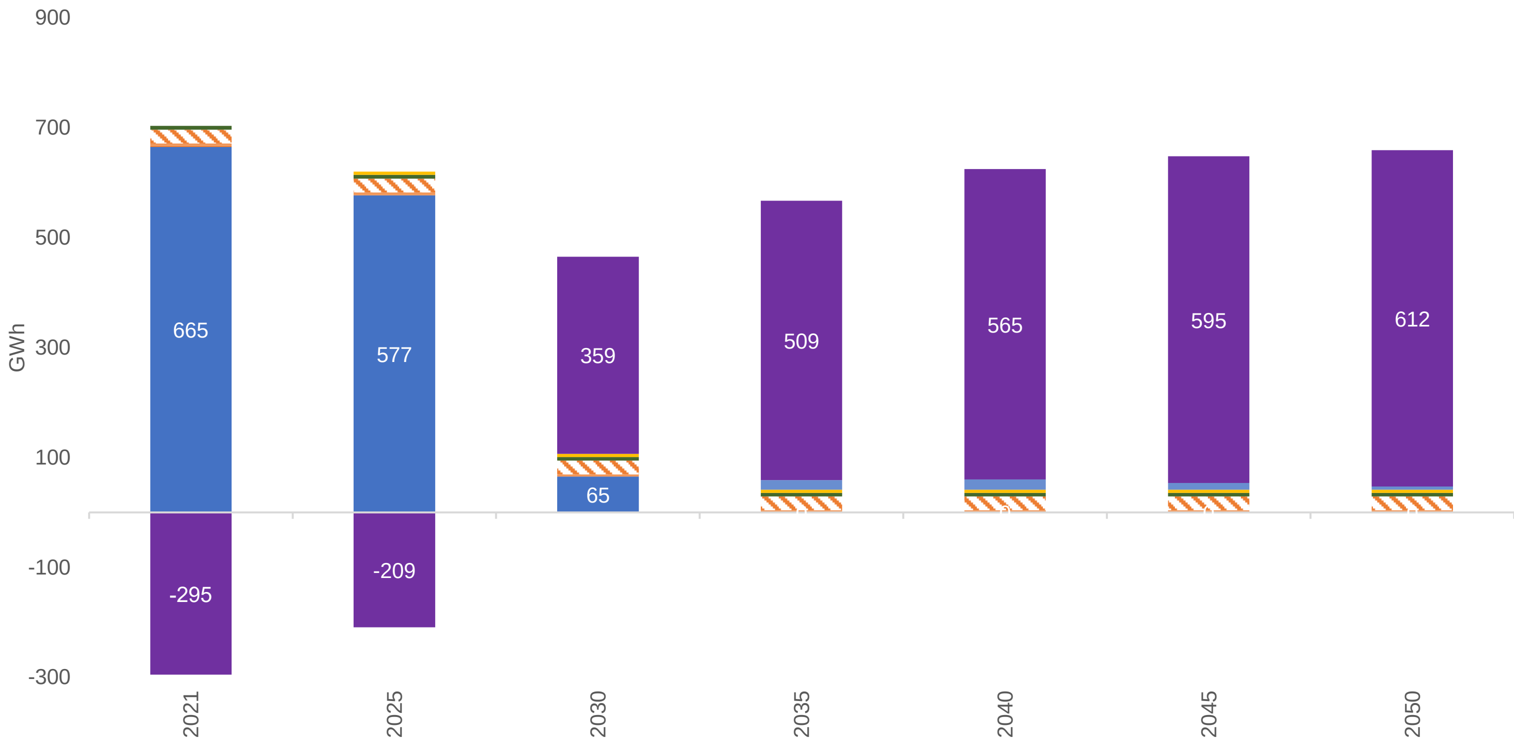
Scenario 2 has the largest interconnector capacity, and hence the highest quantum of electricity imports from the GB market.

LEGEND

- CCGT
- DIESEL
- HYDROPOWER
- ENERGY FROM WASTE (EFW)
- ONSHORE WIND
- BIOMASS*
- SOLAR
- GB TO IOM

*Biomass could potentially be replaced with another carbon neutral biofuel (e.g., biogas or biodiesel

PROJECTED EVOLUTION OF GENERATION MIX (GWH)



- The IoM goes from a **net exporter** to a **net importer** of power by 2050.
- It should be noted that the generation from biomass declines over the forecast horizon. This trend suggests a potential opportunity to further optimise the installed capacity mix by brining forward the operation of the proposed new interconnector. This will negate or reduce the need for biomass and the associated capital and fuel expenditure.
- The generation from the EfW plant is assumed to remain constant over the forecast horizon. This requires validating through the development of a waste strategy, particularly since the plant is currently only operating at c.60% capacity and waste volumes may decline in the future with the wider circular economy and net zero transition. This may have implications for the on-island generation mix.

SOURCE: ARUP ANALYSIS

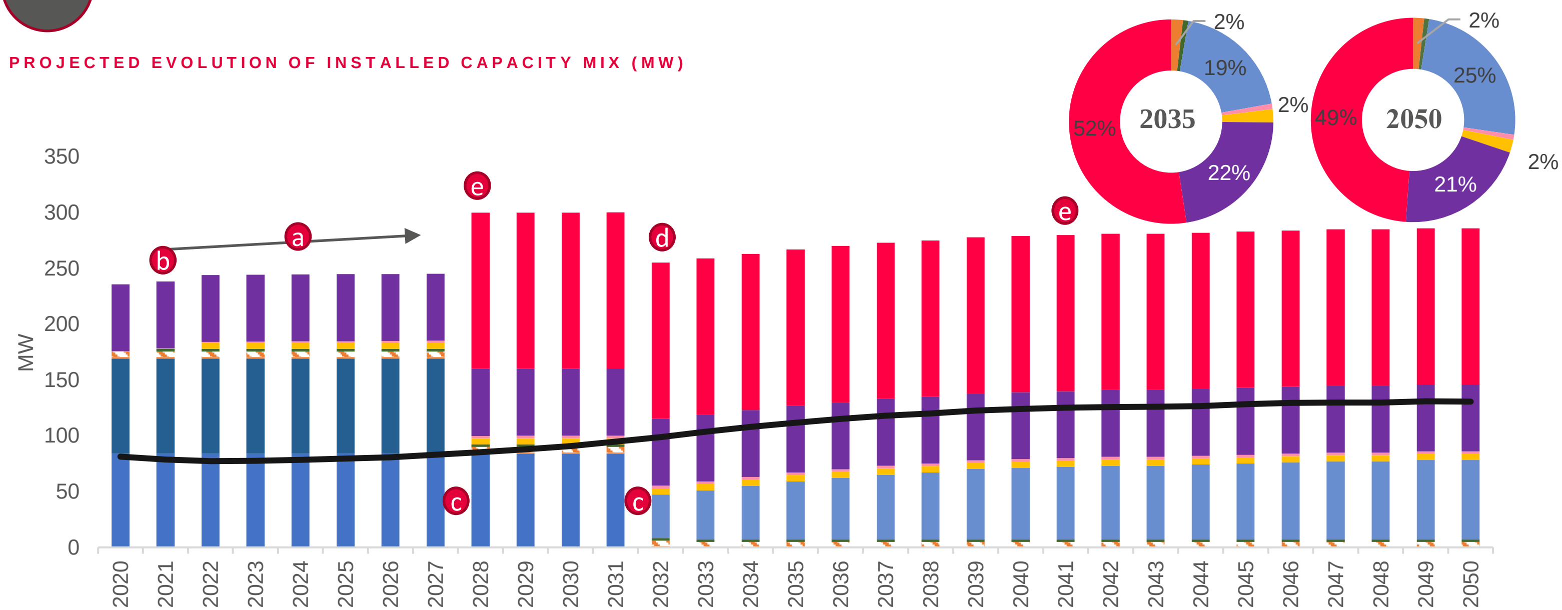
Future Energy Scenarios

Installed capacity(MW): Scenario 3

S3

Scenario 3 has approximately 30% on-island renewable capacity, including biomass, by 2050. The two interconnectors in this scenario also help reduce the reliance on biomass and increase overall resilience level.

PROJECTED EVOLUTION OF INSTALLED CAPACITY MIX (MW)



SOURCE: ARUP ANALYSIS

LEGEND

- CCGT
- DIESEL
- HYDROPOWER
- ENERGY FROM WASTE (EFW)
- ONSHORE WIND
- BIOMASS*
- SOLAR (CENTRALISED)
- SOLAR (DECENTRALISED)
- ENERGY STORAGE
- OFFSHORE WIND
- INTERCONNECTOR
- INTERCONNECTOR (NEW)
- PEAK DEMAND (CT)

KEY OUTCOMES

a This scenario models de-centralisation of renewables through behind-the-meter generation for new properties only. Small amounts of de-centralised and centralised solar become operational from **2021** and **2022** onwards reaching a maximum installed capacity of **2MW** and **6MW** by **2050** respectively**.** It is worth noting there is no current or any future plans for decentralised generation incentives – this is essential to support this consumer led growth.

b **2 MW of onshore wind becomes operational in 2021** and does not increase throughout the forecast period. Similar to other scenarios, this build out is driven by emissions cap and slight uptick in demand from 2022 onwards. It is acknowledged that it may not be realistic to achieve this installed capacity by 2021, and hence capacity expansion may need to be slightly delayed.

c Existing **diesels** and **CCGT** cease operation by end of **2027** and **2031**. **Biomass** becomes operational to maintain resilience following the CCGT ceasing production. **However, there could be commercial benefits if the CCGT was only partly decommissioned and ran in OCGT mode or refurbished (at a cost) to run for longer – this is subject to the amount of hydrogen blended in the gas network in the future, and its compatibility with the existing plant.** Diesels however can't be extended past 2027 as advised by MUA due to issues with the fuel lines.

d **Installed renewable generation** on the IoM doesn't reach **20MW** until **2032**. IoM originally had an ambition to meet 20MW installed capacity target by 2025.

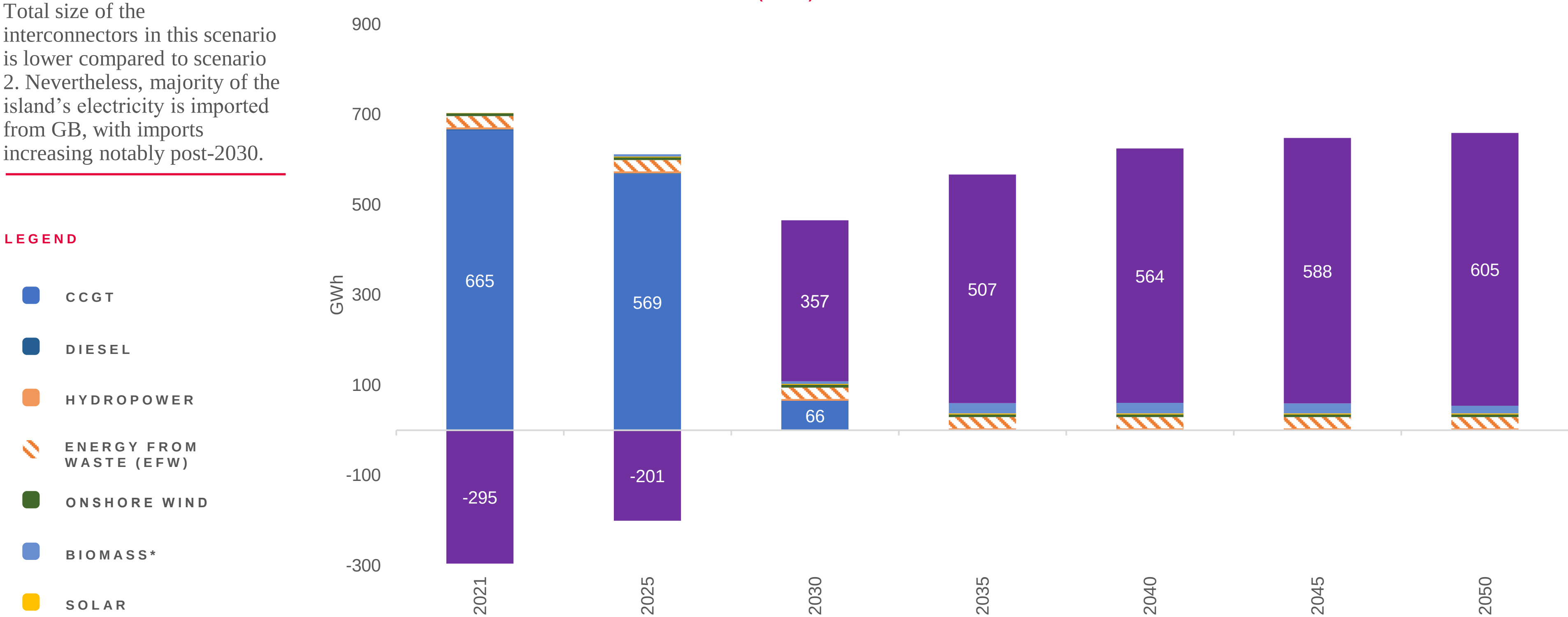
e **Existing 60 MW** AC interconnector is refurbished and stays in service at least out to **2050 (worth noting this may not be possible and should be assessed).** Following the retirement of the existing diesels a **new 140 MW DC** interconnector becomes operational by start of **2028** to maintain the resilience level. This means from **2028** the IoM will have **two interconnectors** in operation.

- Interconnection make up **75%** of installed capacity by **2035** and **70%** by **2050.**

*Biomass could potentially be replaced with another carbon neutral biofuel (e.g., biogas or biodiesel).

Total size of the interconnectors in this scenario is lower compared to scenario 2. Nevertheless, majority of the island's electricity is imported from GB, with imports increasing notably post-2030.

PROJECTED EVOLUTION OF GENERATION MIX (GWH)



*Biomass could potentially be replaced with another carbon neutral biofuel (e.g., biogas or biodiesel)

- The IoM goes from a **net exporter** to a **net importer** of power by 2050.
- It should be noted that the generation from biomass declines over the forecast horizon. This trend suggests a potential opportunity to further optimise the installed capacity mix by brining forward the operation of the proposed new interconnector. This will negate or reduce the need for biomass and the associated capital and fuel expenditure.
- The generation from the EfW plant is assumed to remain constant over the forecast horizon. This requires validating through the development of a waste strategy, particularly since the plant is currently only operating at c.60% capacity and waste volumes may decline in the future with the wider circular economy and net zero transition. This may have implications for the on-island generation mix.

SOURCE: ARUP ANALYSIS

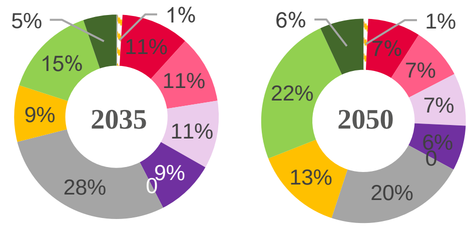
Future Energy Scenarios

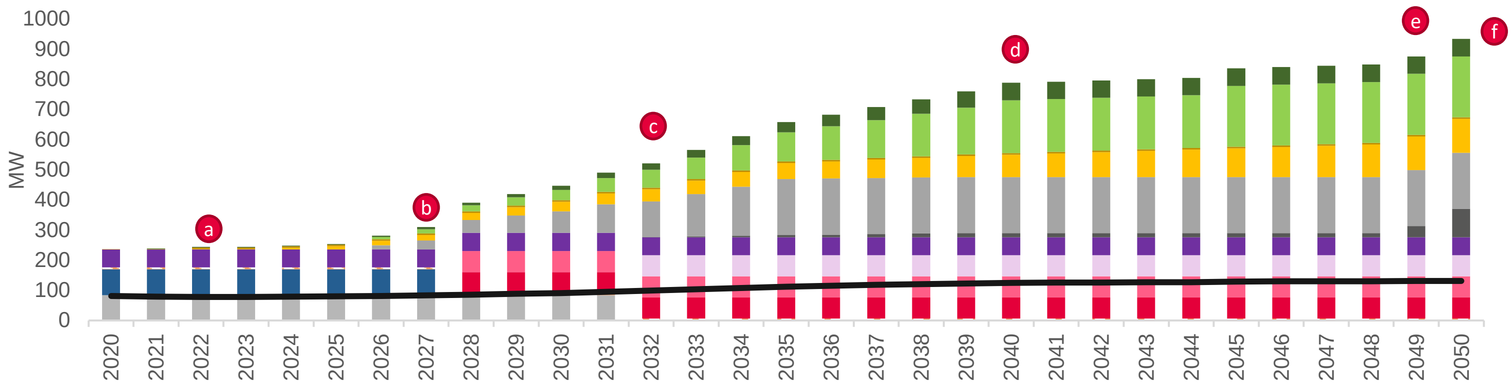
Installed capacity(MW): Scenario 4

S4

Scenario 4 has a significantly installed capacity. This is driven by the desire to maximise on-island generation, minimise imports and maximise behind-the-meter generation.

PROJECTED EVOLUTION OF INSTALLED CAPACITY MIX (MW)





SOURCE: ARUP ANALYSIS

LEGEND

- CCGT
- DIESEL
- HYDROPOWER
- ENERGY FROM WASTE (EFW)
- ONSHORE WIND
- OFFSHORE WIND
- SOLAR (DISTRIBUTED)
- SOLAR (CENTRALISED)
- ENERGY STORAGE (BATTERY)
- *ENERGY STORAGE (PUMPED SEAWATER)
- INTERCONNECTOR (EXISTING)
- INTERCONNECTOR (NEW 1)
- INTERCONNECTOR (NEW 2)
- INTERCONNECTOR (NEW 3)
- PEAK DEMAND (CT)

KEY OUTCOMES

- The modelling for this scenario has followed a different approach, aimed at maximising on-island generation and achieving a higher resilience of N-2.
- This scenario also has a significantly higher proportion of decentralisation in the form of behind-the-meter solar PV generation. It is assumed that 50% of both new and existing properties will have solar PV by 2050.

a Behind-the-meter solar installations need to commence at the earliest in this scenario, and reach 112MW by 2050. Additionally, 5MW of centralised solar capacity is built in this scenario by 2022 to maximise value. However, deployment of centralised solar PV capacity can be delayed until 2025. It is worth noting there is no current or any future plans for decentralised generation incentives – this is essential to support this consumer led growth.

b By the time diesel plant retires in 2027, 45 MW of on-island renewable alongside 30 MW of storage capacity is estimated to be built. Additionally, 2 x new interconnectors of 70 MW each become operational by 2028 under this scenario.

c By 2032, the existing CCGT plant is assumed to be retired and an additional 70 MW interconnector becomes operational. Additionally, total on-island renewables increase to 125 MW, alongside 140 MW battery storage.

d Installed capacity of on-island renewables continues to increase beyond this period, reaching 312 MW by 2040 – this includes 75 MW of behind-the-meter solar PV, 175 MW of offshore wind and 60 MW of onshore wind. Existing 60 MW AC interconnector is refurbished and stays in service at least out to 2050 (worth noting this may not be possible and should be assessed).

e Pumped storage capacity increases to 36 MW by 2049, rising to 94 MW by 2050.

f By 2050, on-island renewables reach 377 MW, alongside 94 MW pumped storage and 186 MW battery storage. Additionally, the scenario has 1 x 60 MW and 3 x 70 MW interconnectors for resilience.

- Early deployment of renewables in this scenario could be challenging. Therefore, there could be commercial benefits if the CCGT was only partly decommissioned and ran in OCGT mode or refurbished (at a cost) to run for longer – this is subject to the amount of hydrogen blended in the gas network in the future, and its compatibility with the existing plant. Diesels however can't be extended past 2027 as advised by MUA due to issues with the fuel lines.

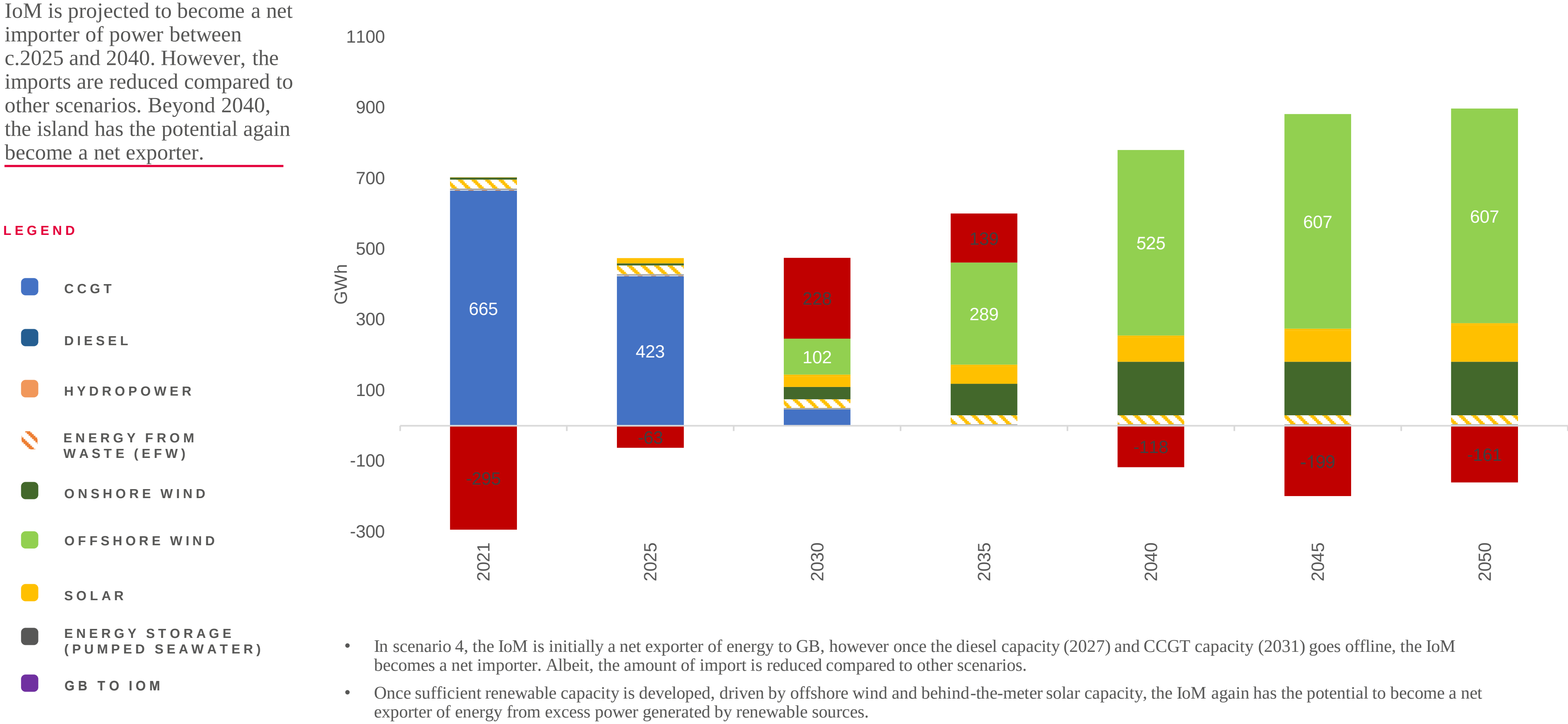
*The environmental impact associated with pumped seawater storage would need to be considered, given it may require roughly c.3 million m^3 of storage – this equates to approximately 67% of the size of the Sulby reservoir. Further assessments are required to confirm the reservoir size and environmental impact.

Generation (GWh): Scenario 4

S4

IoM is projected to become a net importer of power between c.2025 and 2040. However, the imports are reduced compared to other scenarios. Beyond 2040, the island has the potential again become a net exporter.

PROJECTED EVOLUTION OF GENERATION MIX (GWH)



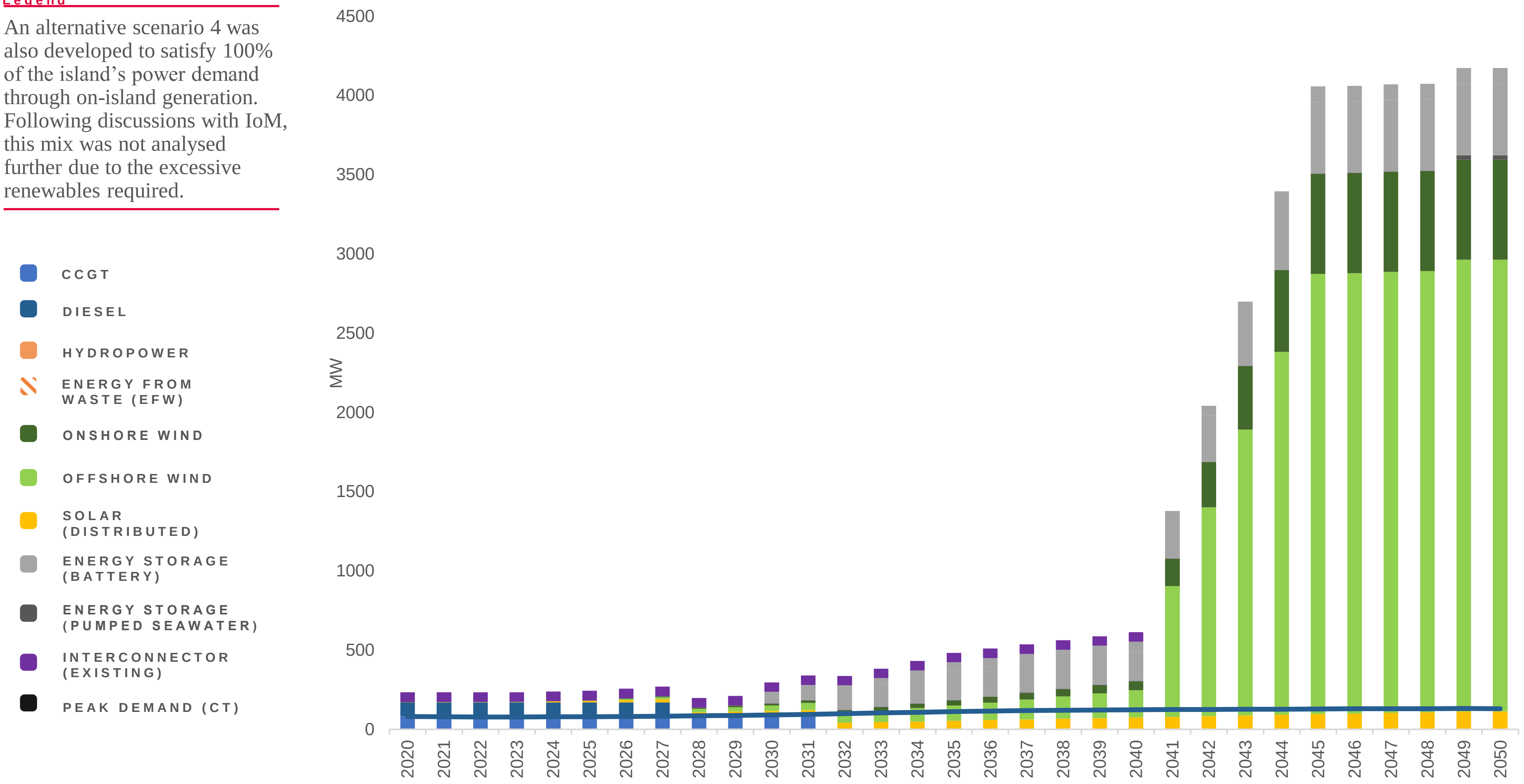
- In scenario 4, the IoM is initially a net exporter of energy to GB, however once the diesel capacity (2027) and CCGT capacity (2031) goes offline, the IoM becomes a net importer. Albeit, the amount of import is reduced compared to other scenarios.
- Once sufficient renewable capacity is developed, driven by offshore wind and behind-the-meter solar capacity, the IoM again has the potential to become a net exporter of energy from excess power generated by renewable sources.

SOURCE: ARUP ANALYSIS

Legend

An alternative scenario 4 was also developed to satisfy 100% of the island's power demand through on-island generation. Following discussions with IoM, this mix was not analysed further due to the excessive renewables required.

PROJECTED EVOLUTION OF INSTALLED CAPACITY MIX (MW)



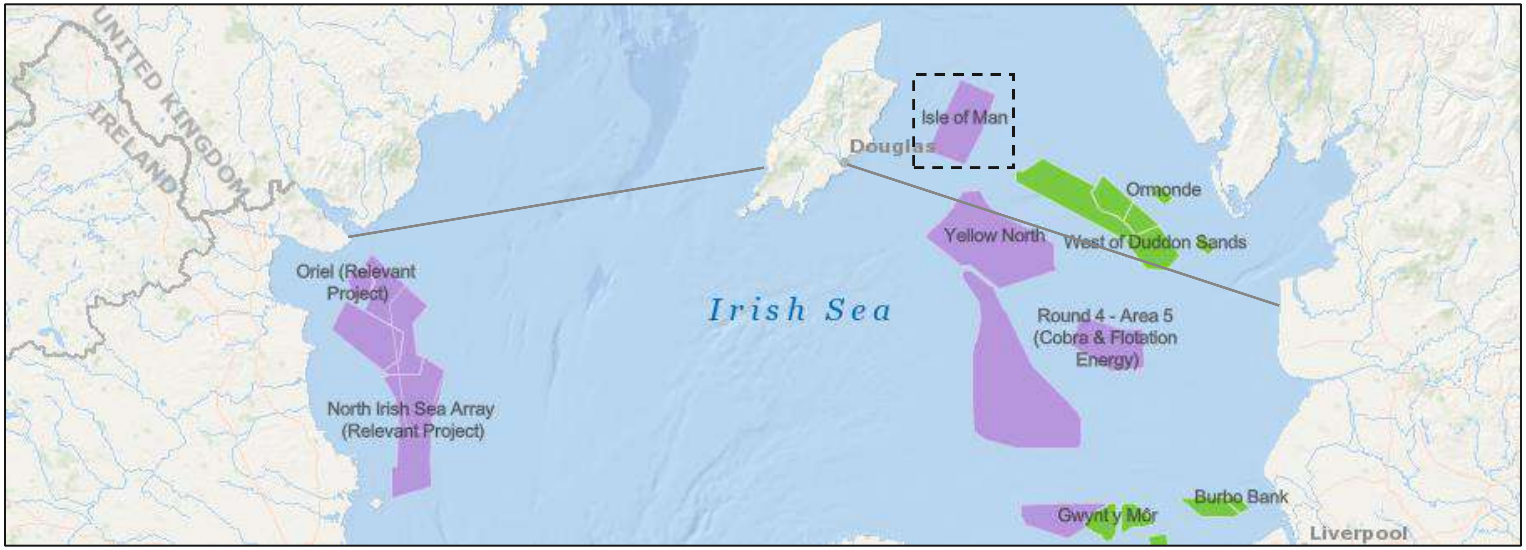
SOURCE: ARUP ANALYSIS

Scenario 5 explores the competitiveness of developing offshore wind capacity in Manx territorial waters against alternatives in Great Britain and the Republic of Ireland.

Legend

- IOM 700-800MW OFFSHORE DEVELOPMENT AREA
- PROPOSED DEVELOPMENT AREAS
- EXISTING DEVELOPMENT AREAS
- POTENTIAL IC CABLES FOR EXPORTING POWER

Irish Sea Offshore Wind Development Locations



Source: 4C Offshore

- Scenario 5 examines and compares the financial implications from a levelized cost of energy perspective of developing a 700-800 MW offshore windfarm within Isle of Man territorial waters in comparison to Great Britain (GB) and the Republic of Ireland (RoI).
- In this scenario, energy generated from the windfarm would land on the IoM via an offshore transmission cable. This energy would first be used to meet domestic IoM electricity demand, with any surplus energy exported to mainland GB (or the RoI) via DC interconnectors, and/or converted to alternative forms of energy for storage (e.g. green hydrogen, compressed air, pumped storage, batteries etc).
- It is understood that Orsted currently hold an ‘Agreement for Lease’ (AFL) contract with the Isle of Man Government Department of Infrastructure, which gives them exclusive rights to develop the area under question. The lease has allowed Orsted to carry out preliminary surveys to determine the commercial, environmental and technical feasibility of developing a 700 MW capacity wind turbine field. The area identified by Orsted (shown in the figure above), covers an area of 253 km3 with a mean dept of 21m below MLWS.
- It is Arup’s understanding from discussions with IoM that the existing license is for Orsted to build an offshore wind farm in the IoM territorial waters and find a route to market for the power. IoM will benefit from the lease of seabed and O&M base, but not from the sale of excess power.

SOURCE: ARUP ANALYSIS

Benefits and Challenges Presented by Scenario 5

The development of a 700-800 MW capacity wind farm will provide economic, societal and environmental benefits for the Isle of Man, however a number of challenges arise from a development of this nature.

Benefits and Challenges of Scenario 5

Benefits

Economic and Societal: The Isle of Man sets to gain from lease of the seabed to the wind farm developer (Orsted), alongside a potential operation and maintenance base on the Isle of Man to facilitate routine maintenance and repair to keep the project operational, providing 'green' jobs and skilled employment to those living on Isle of Man. However, these benefits need to be weighed up against the closure of existing facilities and potential job losses.

Environmental: The development of a 700-800 MW capacity wind farm in Manx territorial waters will provide the IoM with renewable, zero carbon electricity. Such a development will play a key role in decarbonising the Isle of Man economy to meet net zero targets. Whilst this capacity may be theoretically sufficient to meet majority of the island's demand, it should be noted that demand varies during a 24-hour period and from season to season, and generation from offshore wind is intermittent. Therefore, additional capacity in the form of storage of other renewables is likely to be needed.

Challenges

Commercial: The route to market for such a development is currently unclear. Any development in Manx territorial waters would be unable to qualify for UK Government funding via the Contracts for Difference (CfD) mechanism, as the development location is outside of UK Crown Estate boundaries. Therefore, without a government revenue support arrangement, the private developer will be required to arrange alternative arrangements, for example a power purchase agreement (PPA), to secure a reliable source of income. This commercial structure would be more risky than government backed CfDs and could therefore increase project financing costs and hurdle rate.

Regulatory: The development of a 750MW capacity wind farm would require the construction of one or two additional interconnectors between GB (and/or the RoI) to export excess power. Interconnectors interfacing with GB or RoI transmission system operators would require regulatory permission from the respective regulatory bodies of these jurisdictions due to the impact power export would have on the grid. This raises uncertainty around the financing arrangements for any interconnectors alongside the terms with which and desire of energy importers to agree to interconnector developments.

SOURCE: ARUP ANALYSIS

Future Energy Scenarios

Levelised Cost of Energy Model Inputs and Assumptions

Arup has used country specific data to inform the inputs used for the levelised cost of electricity (LCoE) analysis, with some assumptions made for the IoM.

NOTE

Note 1: Capex and Opex figures are given as total undiscounted figures on a per MW basis.

IC Cost refers to the cost of interconnection between two or more locations, and not the cost of offshore transmission cables.

IoM Offshore Development Location

Isle of Man

Source: 4C Offshore, Arup

Scenario	Plant Size	Load Factor	Hurdle Rate	CAPEX	OPEX	IC Cost
IoM Two IC	750 MW	51%	6.3%	£1.94m / MW	£3.3m / MW	£0.38bn
IoM One IC	750 MW	51%	6.3%	£1.94m / MW	£3.3m / MW	£0.19bn
IoM No IC	750 MW	51%	6.3%	£1.94m / MW	£3.3m / MW	-

- Capex, Opex and Hurdle rate inputs sourced from BEIS. IoM specific uplift factor applied to infrastructure component of capex. Load factor based on a sample of locations within the area identified by Orsted. Hurdle rate assumed to remain the same, although a slight uplift in hurdle rate is plausible.

GB Offshore Development Location

Great Britain

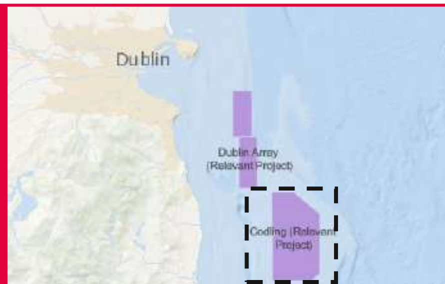
Source: 4C Offshore, Arup

Scenario	Plant Size	Load Factor	Hurdle Rate	CAPEX	OPEX	IC Cost
GB	750 MW	55%	6.3%	£1.89m / MW	£3.4m / MW	-

- Capex, Opex, Hurdle Rate inputs sourced from BEIS. The load factor is based on a sample of locations within the Dogger Bank and Hornsea, two major offshore wind farm developments in off the East Coat of the UK.

RoI Offshore Development Locaiton

Republic of Ireland



Source: 4C Offshore, Arup

Scenario	Plant Size	Load Factor	Hurdle Rate	CAPEX	OPEX	IC Cost
RoI	750 MW	52%	5%	£2.3m / MW	£2.9m / MW	-

- Capex, Opex, Hurdle Rate inputs sourced from EirWind. The load factor is based on a sample of locations within the Codling and Moneypoint potential offshore wind development areas off the coast of the Republic of Ireland.

SOURCE: ARUP ANALYSIS; BEIS; EIRWIND; 4COFFSHORE

Initial analysis suggests that the LCOE for offshore wind in IoM is estimated to be higher than that in GB and RoI. This poses a challenge for the commercial viability of this scenario and warrants further assessment.

LEGEND

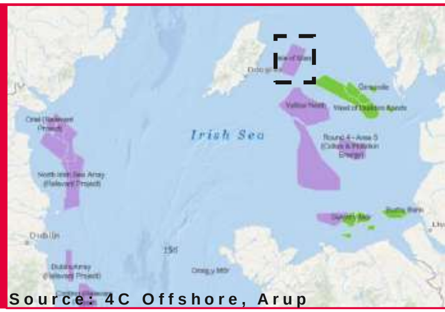
- CAPEX
- OPEX
- IC COSTS
- PROPOSED OFFSHORE DEVELOPMENT

NOTE

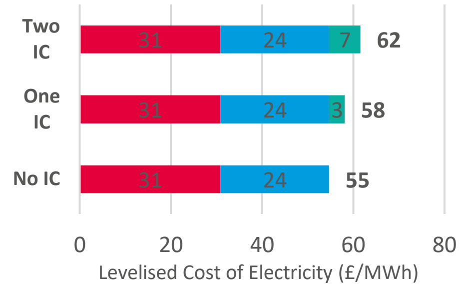
IC Cost refers to the cost of interconnection between two or more locations, and not the cost of offshore transmission cables.

Isle of Man

IoM Offshore Development Location



IoM LCoE Model Outputs

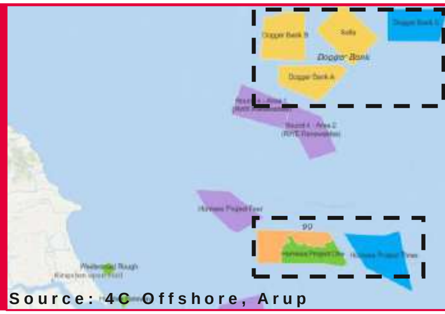


IoM Undiscounted Costs

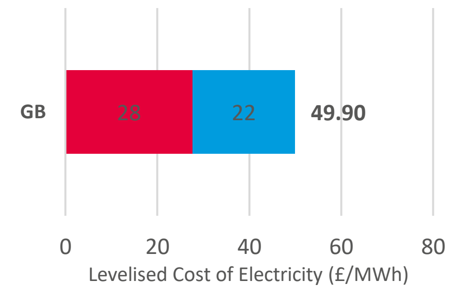
Scenario	Capex	Opex	IC Cost
IoM Two ICs	£1.46bn	£2.50bn	£0.38bn
IoM One IC	£1.46bn	£2.50bn	£0.19bn
IoM No IC	£1.46bn	£2.50bn	-

Great Britain

GB Offshore Development Location



GB LCoE Model Outputs

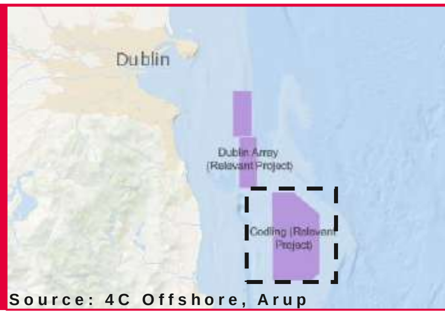


GB Undiscounted Costs

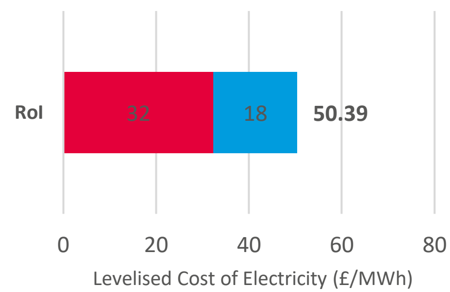
Scenario	Capex	Opex	IC Cost
GB	£1.42bn	£2.53bn	-

Republic of Ireland

RoI Offshore Development Locaiton



RoI LCoE Model Outputs



RoI Undiscounted Costs

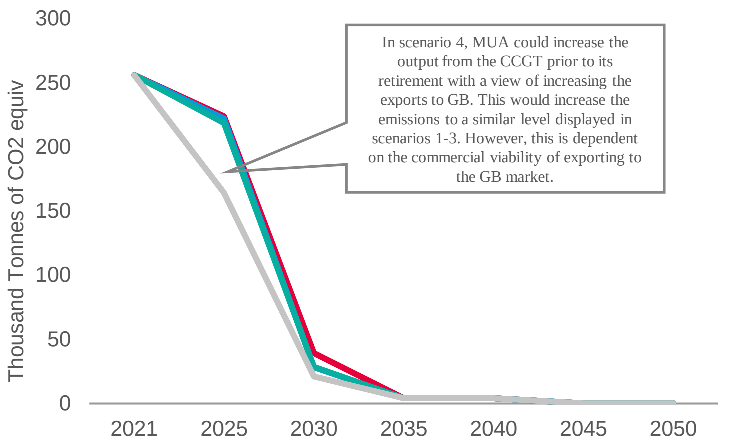
Scenario	Capex	Opex	IC Cost
RoI	£1.74bn	£2.17bn	-

SOURCE: ARUP ANALYSIS; BEIS; EIRWIND; 4COFFSHORE

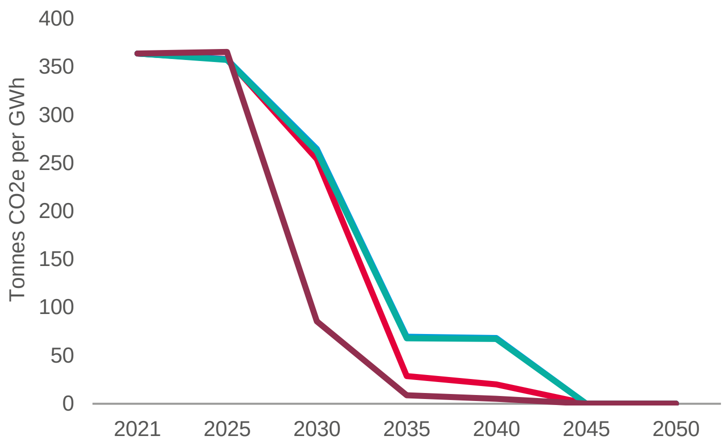
Carbon emissions and intensity declines significantly as the IoM hits Net Zero by 2050 in all scenarios, driven by phasing out of fossil fuel generation, increased imports and renewable penetration.

LEGEND

TOTAL CARBON EMISSIONS (THOUSAND TONNES OF CO2 EQUIV.)



CARBON INTENSITY (TONNES CO2 EQUIV. PER GWH)



CO2 Emissions (THOUSAND TONNES OF CO2 EQUIV.)

		2021	2025	2030	2035	2040	2045	2050
S1	CO2	255	223	39	4	4	-	-
S2		255	222	28	4	4	-	-
S3		255	218	28	4	4	-	-
S4		255	163	21	4	4	-	-

In all scenarios the IoM's climate target of net-zero by 2050 is met earlier than 2050. This means when it comes to implementation of these future energy scenarios, certain investment decisions can be delayed, without jeopardising meeting the 2050 target.

- Carbon intensity (defined in tonnes of CO2 emitted for each GWh of electricity produced) and carbon emissions (million of tonnes) reduce significantly from 2021-2050. Reaching Net Zero greenhouse gas emissions by 2050. The main drivers of this decline are:
    - Less on-island generation from existing fossil fuel plants as these plants reach end of life. Increased installation and generation from on-island renewables and increased imports from GB.
    - The EfW is assumed to burn 100% biogenic waste by 2045.

SOURCE: ARUP ANALYSIS

Estimated wholesale price projections vary for the individual scenarios, with scenario 1 being the most expensive. However, end consumer prices will be determined by how IoM opts to fund and finance the overall transition.

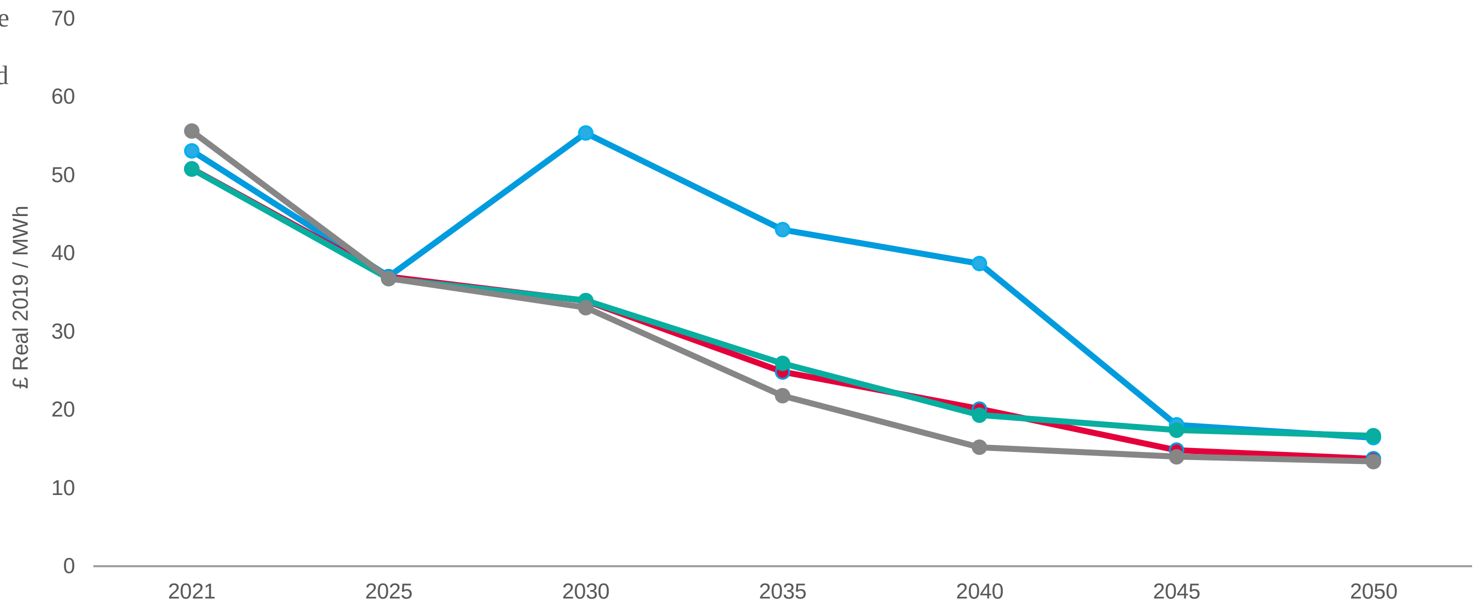
LEGEND

- Scenario 1
- Scenario 2
- Scenario 3
- Scenario 4

The wholesale electricity prices outlined adjacent are aligned to the day-ahead auction market prices. The

Note: Isle of Man doesn't have a wholesale electricity market, therefore the wholesale electricity market prices presented here have been created for a notional IoM wholesale electricity market, with economic dispatch of dispatchable/controllable/programable energy resources either centrally or voluntarily through price discovery in the wholesale electricity market. The projections shown on this slide are based on a series of assumptions, and purely to indicate the relative difference in price amongst different scenarios. This analysis is not intended to inform business case development or investment decisions.

ESTIMATED BASELOAD (AVERAGE) WHOLESALE ELECTRICITY PRICE ON IOM (£ REAL 2019 / MWH)



- Whilst the IoM does not currently have a wholesale electricity market, Arup has modelled a hypothetical market to estimate projected price evolution for individual scenarios. This assessment is indicative and based on a series of assumptions about the evolution of demand and supply across both GB and IoM. Additionally, these projections are based on assumptions about the generation mix evolution which in turn is influenced by technology and cost evolution.
- Wholesale market price projections are typically based on the short run marginal cost – i.e. the cost of generating an extra unit of power. The most expensive power generation unit in the supply stacked from lowest to most expensive required to meet demand will therefore sets the price and drives the projection.
- Whilst the wholesale price projections treat the capital expenditure associated with plants as sunk costs, this capital expenditure is accounted for in the long term capacity expansion, thereby enabling expansion based on the most economic option or generating power, whilst respecting other parameters such as demand, emissions, fuel constraints etc.
- Typically, wholesale prices forming the energy and supply component of a retail bill is the largest single component of the retail price and therefore influences end consumer price. However, end consumer prices are also influenced by network costs, operating costs, supplier margins, taxes and environmental levies that may be charged to fund and finance the energy transition.
- Scenario 4 is estimated to have the lowest wholesale price projection. However, it also has the highest capex. Therefore, whether the lower wholesale prices result in lowest end consumer price is dependent on how the capex is funded and financed.

SOURCE: ARUP ANALYSIS

Key inputs and assumptions, including retirement dates for existing plants, the resilience requirements and how that resilience is provided, have a significant effect on the scenario outcomes.

FACTORS INFLUENCING THE SCENARIO OUTCOMES

- The development of future energy scenarios is based on the energy trilemma framework. This framework, has three key aspects – (1) Environmental Impact, (2) Security of Supply, and (3) Cost / Affordability of Supply.
- In the context of this project, the build-out of generation mix is modelled in such a way that it combines economics and climate constraints to determine the most cost effective solution to build the generation capacity.
- The expansion or addition of all new technologies is undertaken in this manner, with the exception of the interconnectors. Typically, interconnectors are not built in this manner, but instead built based on a strategic need – in the case of Isle of Man, this strategic need is driven by security of supply and grid operability as outlined previously. The interconnectors are therefore 'imposed' on to the model. In this study, the biomass capacity is also 'imposed' on to the model, but with a fuel constraint of 30kT per annum, to fulfil the resilience requirement.
- Across all four scenarios, the existing diesel plants retires by the end of 2027 and existing CCGT plant retires by the end of 2031. These retirements trigger the need to introduce new (i.e. replacement) technologies.
- In Scenarios 1-3, the model also recognises the new interconnectors and biomass capacity 'imposed' on to it to provide resilience. It then builds additional generation plants such as onshore wind, offshore wind and solar PV, based on capacity that is already available to it and the projected demand at a given point in time. Scenario 4 has followed a different modelling approach, wherein the interconnector capacity is added to a generation mix designed with a certain loss of load expectation. This approach for Scenario 4 allows the building of a mix that maximises on-island generation, whilst providing N-2 resilience.
- Additionally, the cost and affordability aspect of the model also evaluates the potential for import and export between the GB and the IoM to inform the capacity expansion on the island. This in turn limits the build-out of on-island generation units.
- Essentially, the resilience requirements imposed on to the model in the form of interconnector(s) and biomass leaves very little room for the model to build additional technologies in Scenarios 1-3.
- A degree of decentralised generation is reflected in Scenario 3 by including a certain amount of behind-the-meter generation. It is assumed that 50% of residential, commercial and industrial new-build premises will be comprised of rooftop solar PV in this scenario. Whilst in percentage terms this may be significant, in overall terms this results in c.2MW of behind-the-meter installed capacity. This quantum is increased significantly in Scenario by including existing buildings; however, significant incentives will be needed to implement this on the island.
- The feasibility of decentralisation on the island is limited, particularly given the vertically integrated nature of Manx Utilities that currently manages the electricity system on the island including generation, transmission, distribution and retail supply. Further decentralisation will require a fundamental change to the market structure on the island, potentially impacting resilience, security of supply and resulting in additional costs for transition and future administration of the network.

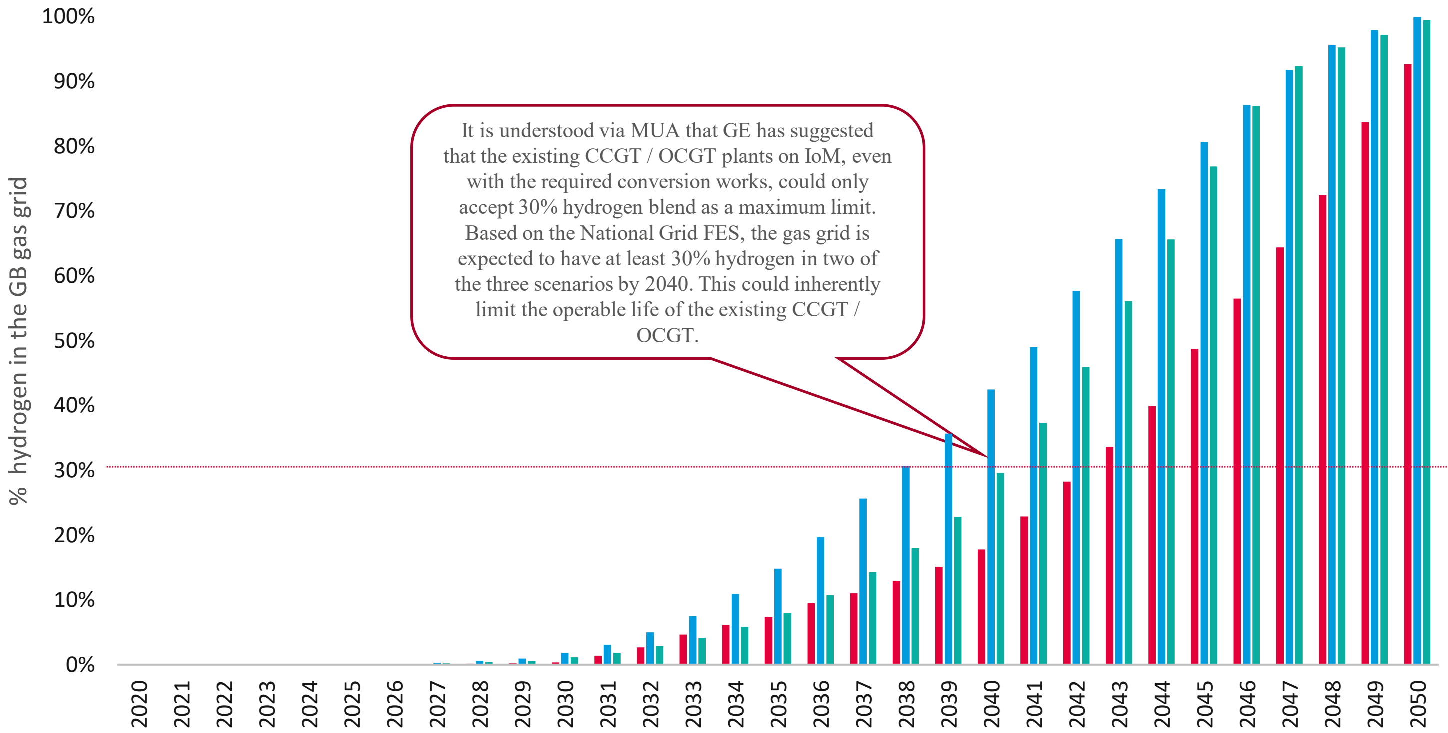
SOURCE: ARUP ANALYSIS

Across all four scenarios, there could be commercial benefits if the CCGT was only partly decommissioned and ran in OCGT mode, or refurbished to run for longer. However, this is dependent on the extent of hydrogen in the gas grid and its compatibility with the existing plant.

LEGEND

- Consumer Transformation
- System Transformation
- Leading the Way

EXPECTED PROPORTION OF HYDROGEN IN THE GB GAS GRID



	2030	2035	2040	2045	2050
CT	0%	7%	18%	49%	93%
ST	2%	15%	42%	81%	100%
LtW	1%	8%	30%	77%	99%

SOURCE: NATIONAL GRID FES

Other considerations: Ancillary services overview slide

The existing AC interconnector enables IoM to benefit from the ancillary / balancing services efforts of National Grid ESO. It is strongly recommended that this AC interconnection is maintained to mitigate additional costs associated with providing these services on the island with a changing generation mix.

ANCILLARY / BALANCING SERVICES

This refers to services procured and actions taken by an operator of an electrical system in order to balance supply and demand and maintain the security (e.g. keeping the lights on when a generator breaks down) and quality of supply (e.g. voltage).

System Operators have an obligation to limit frequency fluctuations to within both statutory and operational limits. In GB and the EU, these limits are a band around 50Hz

Efforts to manage frequency can broadly be grouped into three categories; **Primary**, **Secondary** and **Tertiary Control**. In addition there are **Other Services** which deals with quality of supply or security.

*this is based on high level analysis, a feasibility study would need to be completed to decide which type of interconnector IoM should pursue.

- The Alternating Current (AC) interconnector between GB and the Isle of Man (IoM) sees IoM benefiting off the ancillary/balancing services procurement efforts of National Grid ESO for the GB electricity market.
- Historically the AC interconnector between the IoM and GB is only down for maintenance very seldomly. In these instances, a limited set of ancillary/balancing services (e.g. Primary Control) has been provided by energy resources on the island. Without any AC interconnection with GB, ancillary/balancing services will have to be provided solely by on island energy resources.
- **In the very least it is recommended that the IoM seeks to maintain the existing AC interconnector and if possible adds further AC interconnectors*.**
- High Voltage Direct Current (DC) interconnectors were modelled as part of the four scenarios presented in this study. High level modelling of Primary and Secondary Control requirements, indicated significant amounts of on island biomass and energy storage would be required as a minimum. If the Primary and Secondary requirement were to be met by biomass, the island's ability to sustainably grow the wood required would be exceeded.
- GB utilises a sophisticated array of ancillary services to manage the network, if IoM needed to provide these services, lessons can be learnt from GB.
- Further in depth modelling will be required to provide a comprehensive understanding of the IoM ancillary/balancing services requirements. The table below indicates which of the ancillary/balancing services IoM is able to access through the different types of interconnection:

Ancillary Service	Function	AC	DC
Primary Control	Dynamic and Non-Dynamic Frequency Response in order to maintain system frequency within operation boundaries of 50Hz	✓	◯
Secondary Control	Automatic and Manual Restoration Reserve in order to maintain system frequency within operation boundaries of 50Hz	✓	◯
Tertiary Control	Short-term reserves to restore the automatic frequency restoration reserve	✓	◯
Operating Reserve	The aggregate of headroom above demand and footroom below demand held in order to manage variation in the amount of generation	✓	◯
Energy Imbalance	System Operator buys and sells electricity from participants in the balancing market/mechanism to balance the system	✓	◯
System restoration	Restoration of electricity supply in the event of a blackout through the use of power stations capable of starting up without external power supply	✓	◯
Stability services	The management of inertia, dynamic voltage and short circuit levels	✓	◯
Reactive Power	Management of voltage levels at local / regional level in transmission and distribution networks	✓	✓
Constraint Management	Management of thermal, voltage and stability constraints on the transmission network	✓	✓

SOURCE: NATIONAL GRID ESO AND ARUP ANALYSIS

IoM receives primary, secondary and tertiary control power from GB through the current AC interconnector. Without the AC interconnector the island wouldn't be able to provide the full suite of control power from the existing IoM energy resource.

CONTROL POWER

Primary Control

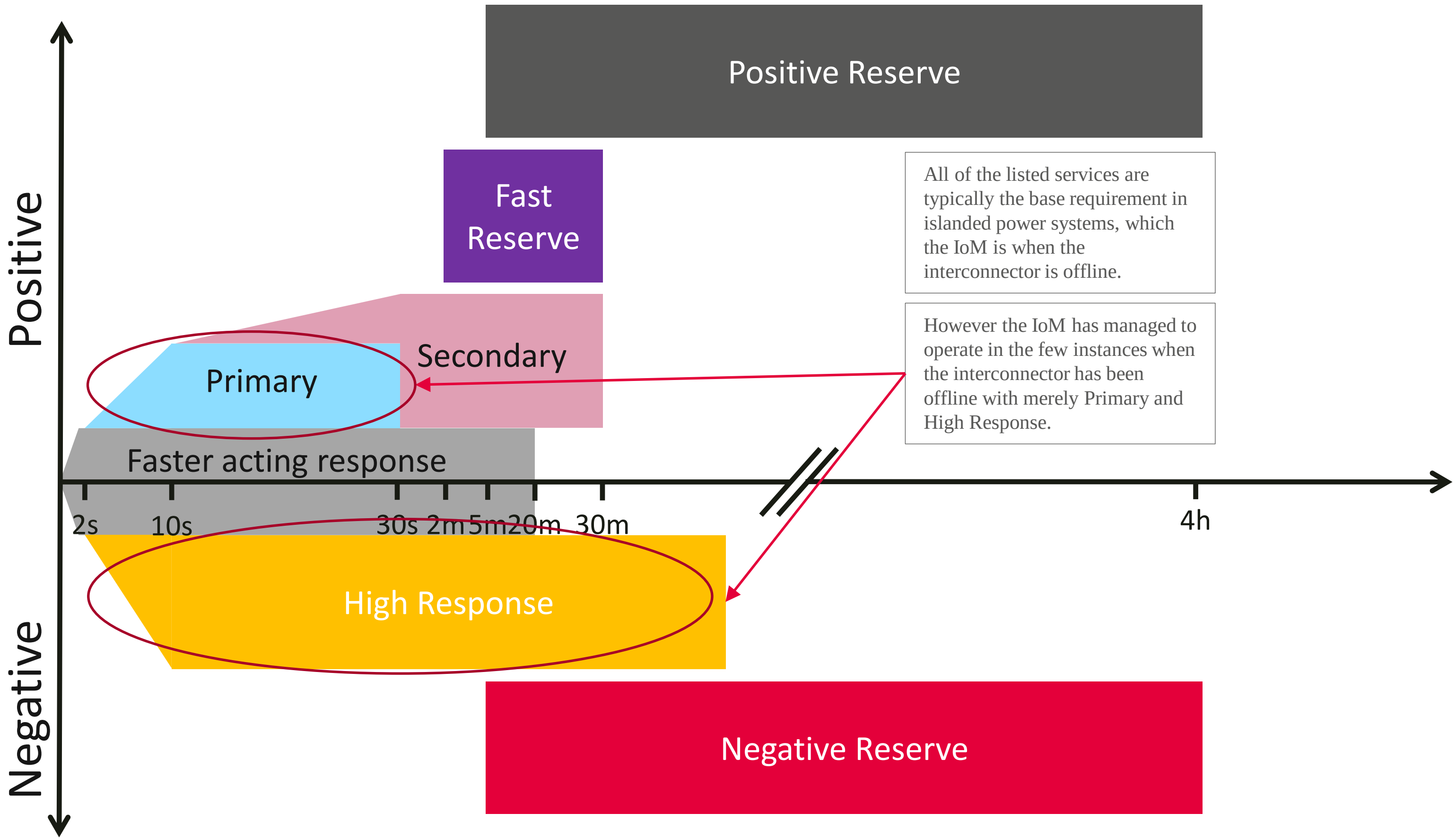
- Faster acting response – positive and negative response from 0.5 seconds for 20 minutes
- Primary – positive response to a low frequency event from 2 seconds and within 10 seconds, maintained for a further 20 seconds
- Secondary – positive response to a low frequency event from 10 seconds and within 30 seconds, maintained for a further 30 minutes
- High Response – negative response to a high frequency event from 2 seconds and within 10 seconds, maintained for at least 30 minutes

Secondary Control

- Fast Reserve – positive response from 2 minutes for 30 minutes

Tertiary Control

- Positive Reserve – positive response from 5 minutes for 4 hours
- Negative Reserve – negative response from 5 minutes for 4 hours



Fast, positive and negative reserve provision are recommended when a power system is islanded for a long period of time.

SOURCE: NATIONAL GRID ESO, ARUP ANALYSIS

Other considerations: Control Power (2)

If the AC interconnection is not maintained to GB, an on-island source would need to provide the full suite of control power. Some energy resources are better suited than others in their capability to provide different types of control power.

LEGEND

✓ Capable of providing the service

✗ Not capable of providing the service

BALANCING SERVICES

- **Primary Control (PC)** – Generator/demand side response within seconds either due to a deviation in the system frequency or a signal from the system operator.
- **Secondary Control (SC)** – An automatic centralised or decentralised service provided by the generator or a demand side responder to adjust the output of a unit if frequency deviation lasts for a longer period.
- **Tertiary Control (TC)** – An automatic or manual change of generator output, in order to restore reserve within minutes.

Energy resources	PC	SC	TC	Comments
Battery Storage	✓	✓	✗	Battery storage has been deployed across the main geographical markets in Europe and is active across DAM, IDM and IM/VB in GB and Germany in particular
Compressed Air Energy Storage (CAES)	✓	✓	✗	Currently there is only one operational CAES in Europe, at Huntorf in Germany, but CAES could have a broad role across multiple markets
Conventional	✓	✓	✓	Conventional generators are relatively high priced providers of ancillary services given the missed revenue from wholesale market needs to be recovered in ancillary services. Conventional generators such as: gas turbines (OCGT, CCGT) or Combined Heat and Power (CHP) systems and Biomass power plants
Demand Side Response (DSR)	✓	✓	✓	Aggregators pool DSR from Industrial and Commercial (I&C) and take them to the markets
Hydro	✓	✓	✓	Run-of-River and Seasonal-storage hydro across Europe compete in these markets
Flywheels	✓	✗	✗	There is very limited operational flywheel capacity in Europe, it is expected to focus on the Primary Control market
Nuclear	✓	✓	✓	In France, the nuclear power plants are operated flexibly. However, they are not operated this way in most other markets/countries. Nuclear power generation is generally sold out in the forwards/futures markets with DAM and IDM trading only used occasionally to manage planned and enforced outages
Peaking plant	✗	✓	✓	Expect the majority of trading to be in these markets given that they will largely be out-of-the-money in forward/futures market and will only come into-the-market during some peak hours. Given flexibility can support Voluntary Balancing Contribution in the Imbalance Market
Pumped Storage	✓	✓	✓	There is significant pumped storage hydro capacity in Southern Europe and Central Western Europe
Wind and Solar	✗	✗	✗	Although the generation output will be forward sold in the forward/futures market, price shape available in the DAM and IDM will be necessary to ensure a sculpted market output profile

DIMENSIONING / SIZING GUIDANCE

- **Primary Control (PC)** – Largest single infeed loss. Only required when there is no AC interconnector between IoM and GB; during planned maintenance and/or retirement of current AC interconnector. Currently equal to Pulrose CCGT in OCGT mode (circa. 40 MW) or Pulrose Diesel (50 MW) if operational.
- **Secondary Control (SC)** – Maximum volume equal to approx. 75% largest single infeed loss during demand ramps, down to 0 overnight.
- **Tertiary Control (TC)** – An automatic or manual change of generator output, in order to restore reserve within minutes. Approx. 4 times largest single infeed loss (positive) and 2.5 times largest single infeed loss (negative).

SOURCE: NATIONAL GRID ESO, ARUP ANALYSIS

Other considerations: Cost of providing GB level on ancillary services

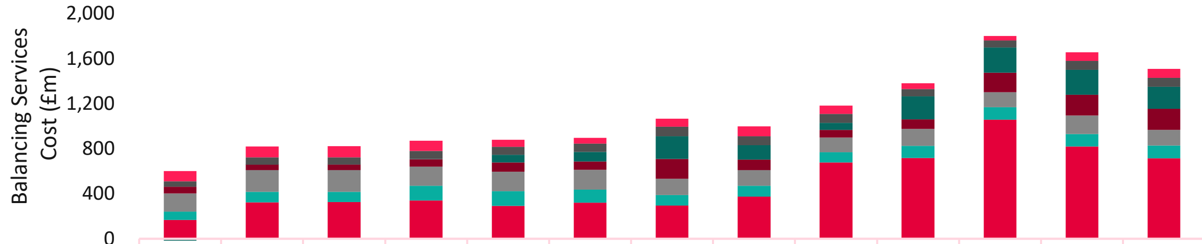
Significant investment and additional analysis will be required to provide the ancillary services through on-island provisions, instead of them being provided by GB.

Primary- Frequency response

Secondary- Fast reserve

Tertiary- Short- Term Operating Reserve and Operating reserve

ESTIMATED BALANCING SERVICES COST BREAKDOWN GB (2010-2021)



	2010/11 (A)	2011/12 (A)	2012/13 (A)	2013/14 (A)	2014/15 (A)	2015/16 (A)	2016/17 (A)	2017/18 (A)	2018/19 (A)	2019/20 (A)	2020/21 (F)	2021/22 (F)	2022/23 (F)
Short-Term Operating Reserve (STOR)	90	98	97	91	62	49	72	88	74	53	40	77	77
Reactive Power	48	64	64	70	72	76	86	79	81	65	63	81	81
Other Components	-17	1	1	3	68	84	200	129	62	205	224	219	196
Operating Reserve	61	49	50	65	81	75	176	92	67	83	173	186	186
Frequency Response	163	193	192	171	174	174	145	140	132	152	134	164	140
Fast Reserve	71	92	92	130	130	117	94	97	91	108	110	112	112
Constraint Management	169	324	326	340	293	321	295	374	677	717	1,058	819	716

- The chart above displays the annual spend for providing the required level of ancillary services on GB, important to note this is the price to the market from installed plants of providing that service and does not take into account the capital costs of installing that plant or the operational costs of running it.

Scaling the GB Ancillary costs to IoM

- If the IoM lost the existing AC interconnector, ancillary services provision is required on island to keep the grid operable.
- Currently the island manages to provide a minimal set of ancillary service and keep the grid operable, but this is by no means extensive.
- As demand increases and the generation mix evolves in the future become increasingly more complex, the quantity and diversity of ancillary services requirement will also increase.
- Arup have produced a high-level approximate estimation of what it would cost (assuming IoM already had the required plant capacity installed) to provide this services. As the GB has a more complex system, we have only done an estimate based on what **services we consider to be core to the IoM (primary, secondary and tertiary).** It would be important however to understand what other services are required (such as constraint management), but this would require more detailed analysis.
- GB has spent annually on average **£ 1.3m/TWh (electricity demand)** on these **services we consider to be core to IoM**. Similar cost may be incurred in IoM..

SOURCE: NATIONAL GRID AND ARUP ANALYSIS

While there are parties on the IoM who would like to explore community generation on the island, this requires further consideration to make this possible and assess its feasibility.

DEFINITION STATEMENT

"Community generation refers to renewable and alternative energy that is distribution system-connected and provides benefits to communities. Community generation allows communities and citizens to directly participate in energy projects through full or partial ownership of the projects."

- Alberta Community & Co-Operative Association (ACCA)

Community generation is a useful additional feature to give people equity in their energy generation and transition at large. However, other non-community generation approaches are likely to have a greater impact on the transition given that great funds are available from private companies and central governments.

Key Characteristic	
Funding and financing	• Much of the power generation assets across the globe are either government or privately owned, with well established ownership and operating models. Arguably, this makes it easier for the private sector to raise capital, and to fund and finance both existing and new assets. • Whilst community-based schemes may find it more difficult to gain access to private finance or public finance, communities can raise bonds from within. Such bonds or equity stakes can also enable the community to retain profits made from excess generation, if any.
Ownership and operation	• Community based generation assets can be owned under one of several models – co-operatives, partnerships, non-profit organisation, community trusts and housing associations. • However, technical and operational knowledge can often be a limiting factor in successful ownership operation of such assets. Building the necessary capacity and capability is therefore vital.
Resilience of supply	• Community based generation is often located close to the source of the demand (i.e. the community). This can often enable better deployment of distributed renewable generation. If the generation assets are sized to produce excess power, then this can provide additional resilience for the grid too. • For IoM, the potential to oversize biomass, onshore wind and solar PV is very limited. Hence, community based generation is unlikely to result in additional resilience for the grid • The scenarios developed in this study provide resilience predominantly through biomass and / or interconnection. Having several different smaller biomass plants will impact operations, land-use, efficiency and consequently have financial implications.
Implications for the network	• Typically, having generation assets at distribution level can reduce the need for large scale grid reinforcement. However, for smaller geographies, the benefits reduce as the disparity between good generation sites and demand sources reduces. • Island's network is designed around a handful of large generators, predominantly the diesel and gas. Greater number of distributed renewable assets may therefore result in more network reinforcements being required.
Regulatory considerations	• Policy and regulatory frameworks are typically designed around privately-owned or government-owned generation. These will need to be reviewed and appropriate changes will need to be introduced to support the growth of community based generation if deemed necessary. • A new operating model for the island's electricity network will also need to be developed. The network is currently managed by Manx Utilities as a vertically integrated entity. If community generation is pursued, then new entities, and associated regulatory and governance structures will also need establishing.
Implications for end consumer	• Community-owned generation is often located in close proximity to the source of demand. Consequently, the associated network and its management can be comparatively small, and therefore have the potential for lower energy cost for the community. • If the projects are designed to have surplus electricity, then excess power can be sold to the grid or other (e.g., via a power purchase agreement), resulting in an additional revenue stream. • However, it is possible that community based generation schemes , particularly on small islands such as IoM, may increase the cost for those who are not connected to the scheme.

6. NETWORK IMPLICATIONS

The IoM transmission and distribution network is owned and operated by Manx Utilities.

In future, it is likely that more generation will connect to the distribution network (11 kV and below). This is likely to be smaller capacity renewable generation such as solar and biomass plants.

The transmission network (33 kV) is designed to remain operational with the loss of any individual 33 kV circuit or substation due to maintenance or an unplanned outage. In this instance, it runs in a radial rather than meshed configuration.

Critical areas of the distribution network at HV are run in a meshed configuration e.g. in city centres. The HV network and urban LV networks have alternative in-feeds available in the event of maintenance or an unplanned outage, to minimise the risk of loss of supply.

Interconnector

- Connects to the Electricity North West 132 kV transmission network in the UK

Transmission (33 kV)

- Comprised of nine 33 kV substations and circuits (overhead lines and underground circuits) connected in a solid meshed configuration
- Interconnector, CCGT and diesel generators are connected to transmission network
- Transmission (33kV) circuit ratings have a nominal value of 20MVA

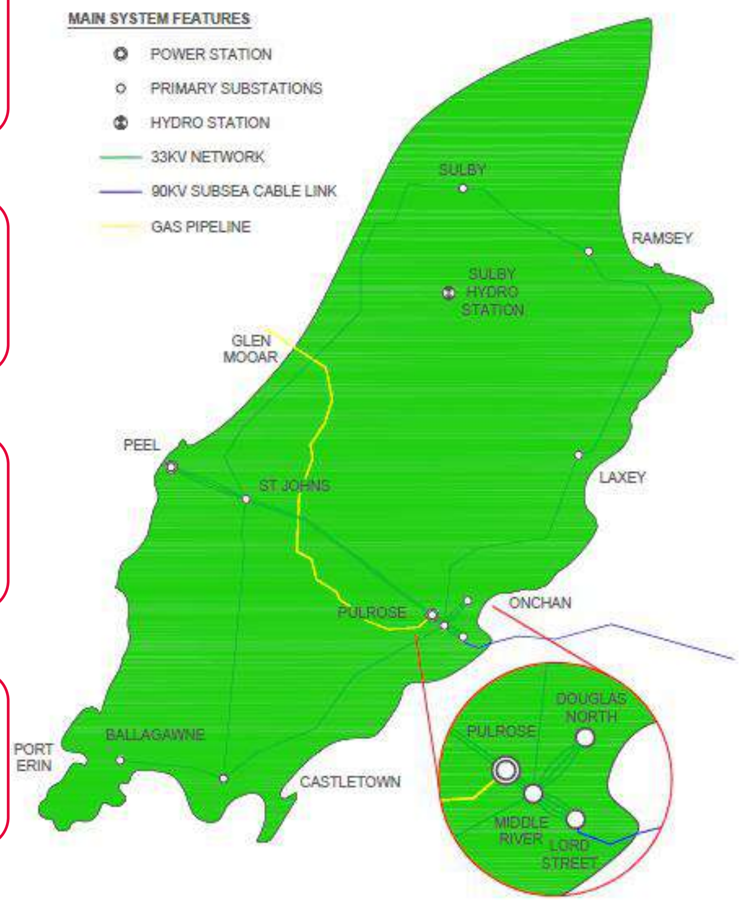
Distribution (HV)

- Transformers at 33 kV substations connect to the electricity distribution network
- Comprised of 11 kV and some legacy 3.3 kV circuits (overhead lines in rural areas and underground cables in more urban areas)
- Mostly run in an "open-ring" configuration with alternative in-feeds available

Distribution (LV)

- Distribution transformers connect the HV and LV networks
- Comprised of LV circuits – overhead lines in rural areas and underground cables in more urban areas
- Run in an "open-ring" configuration in urban areas with alternative in-feeds available , rural areas are spurs
- Most customers are connected to the LV network

MAP OF ISLE OF MAN GRID



The IoM electricity network has reasonable levels of capacity at present, at both transmission and distribution network level.

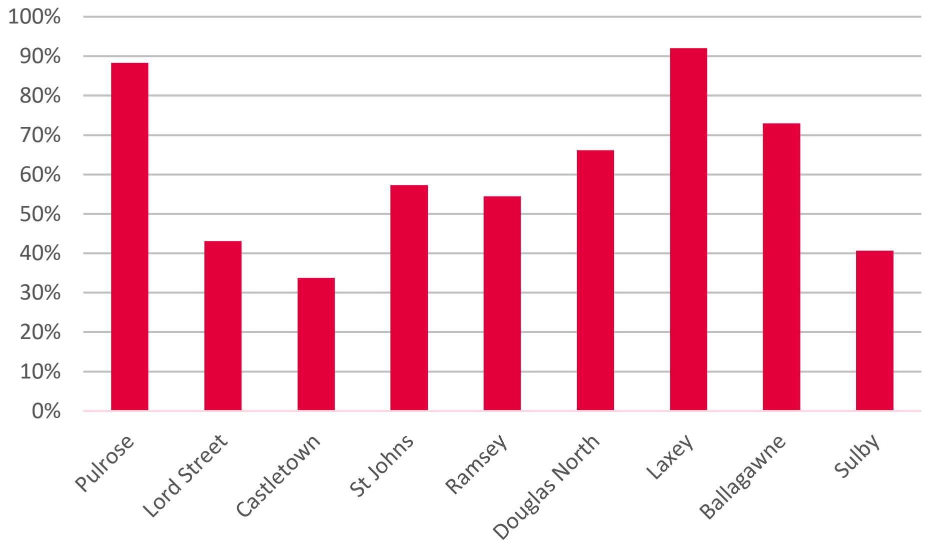
Electricity networks are designed to operate under peak load (worst-case) conditions. These are typically associated with cold winter evenings.

When network power flows approach or exceed asset ratings, these assets are replaced by assets of a higher rating and/or new assets are added to the network to share the load. This is also required when voltage limits along circuits are exceeded.

When new generation or demand customers are connected to the network, new assets are required for expansion or upgrades to allow more capacity.

The extent of these depends on the capacity of the new connection and its location in the distribution or transmission network.

TRANSMISSION SUBSTATION UTILISATION AT PEAK DEMAND IN 2019



DISTRIBUTION SUBSTATION UTILISATION AT PEAK DEMAND

	No.		Rating	Ave Max Utilisation 2020/21
Urban	600	Ground mounted	315-1000 kVA	40%
Rural	420	Pole mounted	16-100 kVA	20%

Network Monitoring

- All primary transformers and HV feeders are feeders are monitored.
- Monitoring has been deployed at one third of secondary substations to date with plans to implement for all. This is connected on the LV side of the transformer and monitors the transformer only.
- Customer smart meter rollout in progress and will be completed over the next 4 years. SMETS2 type meters for electricity only.

Voltage control

- Primary substations have automatic voltage control.
- No voltage control in the distribution network.

Asset Condition

- Some asset age/condition related investment is likely to be required over the next 5-10 years, the following investment needs have been identified by Manx Utilities:
- Several transmission substations need renewal.
- Refurbishment of large sections of transmission overhead lines.
- Replacement of HV distribution ‘oil filled ‘ switchgear with modern switchgear.
- Gradual replacement of LV overhead ‘open wire’ circuits with ABC (aerial bunch conductor) for improved safety and resilience.

The need for investment in the network is triggered by a series of factors across both demand and generation side. This investment enables the necessary strengthening and operability of the network.

WHY NETWORK UPGRADES ARE REQUIRED

Electricity networks are designed to operate safely under worst-case peak demand conditions. As demand increases, the network needs to be strengthened to ensure security and quality of electricity supply to all customers.

New generation and interconnectors may also require network strengthening to ensure that generators can supply electricity to demand across the island. The network must be able to cope with maximum output from each generator although, in reality, not all generators would be operating at maximum output at the same time. This is due to the need for redundancy in generation

NETWORK INVESTMENT TRIGGERS

New generation

New generation – renewables

Interconnectors

New generation – biomass

New demand

Electric Vehicles

Electric Heating

New Industry

New Housing

New Commercial

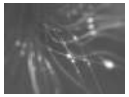
NETWORK OPERATION INVESTMENT

More ancillary services

Wider monitoring and control

NETWORK STRENGTHENING INVESTMENT

New overhead lines



New underground cables

New substations and transformers

Source: IEMFG

Network investment requirements, triggered by demand evolution, are highest for the Consumer Transformation scenario, which has the highest demand growth.

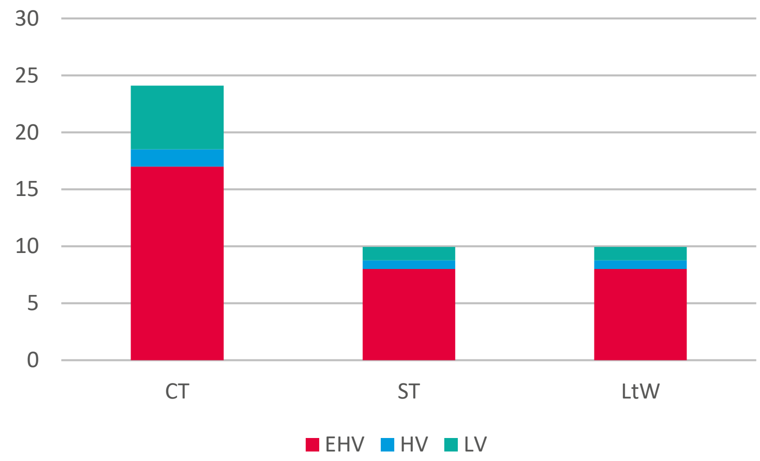
METHODOLOGY

Manx Utilities carried out power flow modelling to identify capacity and voltage constraints on the transmission and 11 kV distribution network using peak demand from Arup demand scenarios. They then estimated corresponding capital investment requirements. It was assumed that demand load growth is distributed fairly evenly across the network. In reality, there will be some clustering which will most impact the LV network.

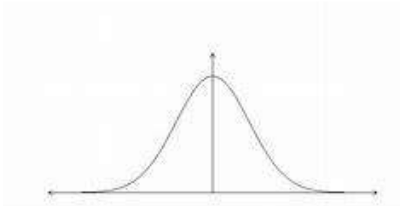
Generation supply was based on existing generation locations with output scaled up to match the demand requirements in each demand scenario. Please note that generation investment requirements are relatively decoupled from demand investment requirements.

Arup estimated the levels of investment required on the LV network for each scenario using high-level statistical desktop modelling.

NETWORK INVESTMENT TO 2050 FOR EACH DEMAND SCENARIO IN £M



Scenario	Peak Island Demand (MVA)
CT	131
ST	115
LtW	115



Normal distribution model of LV circuit peak utilisation across the population of LV circuits on the Isle of Man

SOURCE: IOM AND ARUP ANALYSIS

All demand scenarios trigger investment on both the transmission and distribution network, as expected.

Transmission Network (33 kV) Network

- Power systems modelling carried out by Manx Utilities indicated that there were a number of locations on the transmission network that needed reinforcement due to exceedance of circuit or transformer ratings or the limit of acceptable voltage drop.
- These reinforcements were triggered at various peak island demand thresholds in the Arup demand scenarios to 2050. Reinforcements requirements are lower for ST and LtW demand scenarios which follow a lower demand growth trajectory to 2050.

Distribution Network (HV)

- Power systems modelling carried out by Manx Utilities indicated that there were a small number of locations on the HV distribution network (including HV/LV substations) that were either close to circuit capacity or on the limit of acceptable voltage drop under maximum peak island demand for the CT scenario; however, these could all be resolved through conventional network interventions.
- The need for reinforcement of the HV network is expected to be proportionally somewhat less under the ST and LtW demand scenarios compared to the CT demand scenario, similar to the transmission network.

Distribution Network (LV)

- Desk-top modelling was carried out by Arup to estimate the levels of reinforcement and thus, investment needed for LV networks under each Arup demand scenario.
- It was assumed that there is a normal distribution of LV circuit demand around a mean of the average existing peak utilisation of LV rural and urban networks (provided by Manx Utilities). This distribution shape was based on the demand diversity characteristics of LV customers from the Customer Led Network Revolution innovation project.
- Overlaying Arup's demand scenarios enabled identification of the approximate magnitude of rural and urban LV circuits that may to exceed their rating up to 2050. Corresponding investment costs for new/upgraded circuits were then estimated based on typical urban and rural circuit lengths and unit costs..

Network investment triggered by new generation connections

Network investment requirements, triggered by generation mix evolution, are highest for Scenario 2, which requires the grid integration of two new 140MW interconnectors.

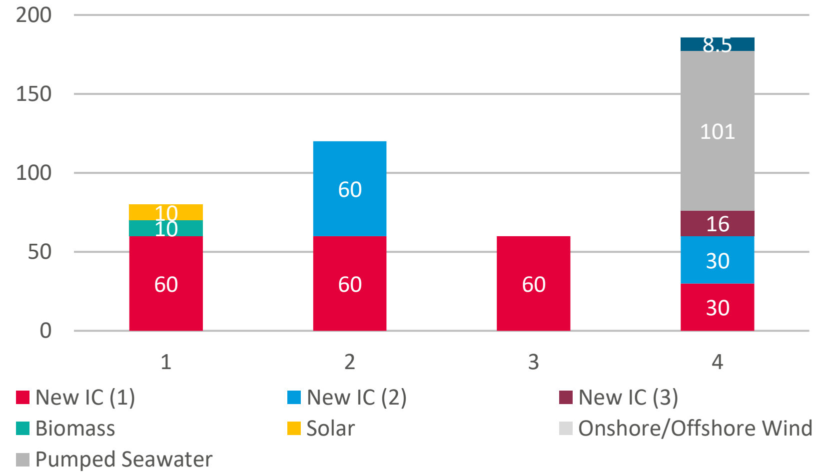
METHODOLOGY

Generation connections of up to approximately 20MW (in aggregate) can connect to a number of locations in the transmission network with minimal implications for network investment. Larger generators will trigger the need for wider network reinforcement. The scale of reinforcement to the transmission network will depend on the capacity needed and the location of connection as well as wider system implications.

Arup collaborated with Manx Utilities to identify transmission network upgrades and approximate corresponding capital investment requirements for new generation and interconnectors in the four scenarios.

We have assumed that private generation developers would cover a material proportion of any wider network reinforcement costs due to their generation connections.

NETWORK INVESTMENT TO 2050 FOR EACH GENERATION SCENARIO IN £M



TRANSMISSION NETWORK REINFORCEMENT TRIGGERS DUE TO GENERATION CONNECTION

Scenario	140MW IC	140MW IC	Large Biomass Connection	Large Solar Connection
1	2041		2031	2039
2	2028	2041		
3	2028			

Scenario	70MW IC	70MW IC	70MW IC	Large Onshore Wind	Large Offshore Wind	Large Pumped Seawater
4	2028	2028	2032	2040	2030, 2040	2050

Other technical considerations for generation connections:

- Voltage issues can arise for distributed generation particularly where they are connected to rural networks with long circuits.
- The AC interconnector cable currently provides high levels of inertia and fault current capability. Inertia enables a power system to stabilise itself under sudden changes such as in the event of a fault which results in the loss of a large generator. Fault current contributes to system strength and ability of a system to “ride through” a fault.
- New synchronous (rotating) generators can also provide both inertia and fault current capability.
- Converter-based generators such as solar PV and wind are not able to supply much fault current in the event of a fault do not provide a necessary inertia. Similarly, DC interconnectors are also limited in this respect. Inertia contributions can be increased through emulation.
- Converter-based generation such as solar PV and wind can also contribute to increased levels of harmonics (and thus, reduced power quality) in a power system.
- It is important to understand the impact of new generation connections on the performance, security and safety of the power system, ensuring grid code compliance at the point of connection and maintaining the overall performance of the system. Technical and operation solutions exist to help mitigate some of the issues described above.

SOURCE: IOM AND ARUP ANALYSIS

The deployment of "smart" solutions and flexibility services can help to defer, or in some cases, avoid costly network reinforcement.

Smart solution – network asset based solution that can be deployed by the electricity network owner.

Flexibility service – market based solution that uses price signals or contracted services for demand/generation changes. Can be local or system wide.

These can often be deployed much more quickly than large reinforcement schemes and can help address rapid load changes due to clustering in areas of the network.

Some of the more commercially viable options are presented in the table here.

Smart Solution	Applicability	Commercial Readiness	Advantages/ Disadvantages
Dynamic thermal ratings	Works on the principle that thermal asset ratings are fundamentally temperature-based. Peak demand coincides with low ambient temperatures for transformers, high wind generation coincides with high wind cooling of overhead lines.	Deployed commercially at scale in GB	Relatively low cost, increase in thermal capacity of around 10%+
Advanced voltage control	Can be installed on primary and secondary substation transformers and along circuits (voltage regulators). Addresses voltage drop or rise across the network and/or along lengthy circuits.	Deployed commercially at scale in GB	Relatively low cost, does not address thermal issues
Active Network Management	Manages output of generation for multiple generation connections in a constrained part of the network to avoid high reinforcement costs. Typically based on modified connection agreements.	Deployed commercially at scale in GB	Relatively low cost, requires increased monitoring and control
Network reconfiguration and meshing	Transfer or share loading more equally across the network, can be implemented dynamically. Some networks are already meshed for these benefits. Depends on network configuration and connectivity.	Deployed commercially at scale in GB	Relatively low cost, dependent on specific networks

Flexibility Services	Applicability	Commercial readiness	Advantages/ Disadvantages
Smart EV charging	Aggregated monitoring and control of EV charging.	Not deployed at scale yet	Low cost once EV uptake increases
Demand side response	Customers respond to price signals during peak demand or off-peak times to change usage of network. Customer and supplier needs to have visibility of demand use through smart meters.	Not deployed at scale yet	Low cost, requires half-hourly settlement
Flexibility services – DNO	Distributed energy resource (can be demand or generation) contracted by DNO to provide specific change in load to resolve a network constraint.	Deployed commercially at scale in GB	Needs sufficient market confidence and liquidity to be efficient

SOURCE: ARUP ANALYSIS

7. FINANCIAL CONSIDERATIONS

Arup has modelled four key cost components for the financial considerations analysis. These include capex, opex, fuel cost and network cost.

- *Costs presented here are benchmark costs based on similar projects Arup has completed in GB. Additionally these have been sense-checked against the BEIS cost of generation report 2020.
- **It is worth noting there may be slight differences between these standard costs for the exisiting technologies and the IoM actual costs, especially as the IoM electricity sector is government owned. However, these should be insignificant given the main cost of the future energy scenarios is the new technology installations and the existing technology evolution is practically the same in all scenarios, so will be immaterial on a cost comparison basis as well as a total cost level.

MODELLING METHODOLOGY

Modelled Cost	Components modelled
Capex	• The construction and pre-development cost of new technologies. • Interconnection capex.
Opex	• Fixed and variable operational cost of existing and new technologies • Annual operating costs for the interconnectors.
Fuel	• Fuel consumption costs of new and existing technologies (gas, diesel and biomass).
Network	• Capital costs for new network assets.

COST INPUTS

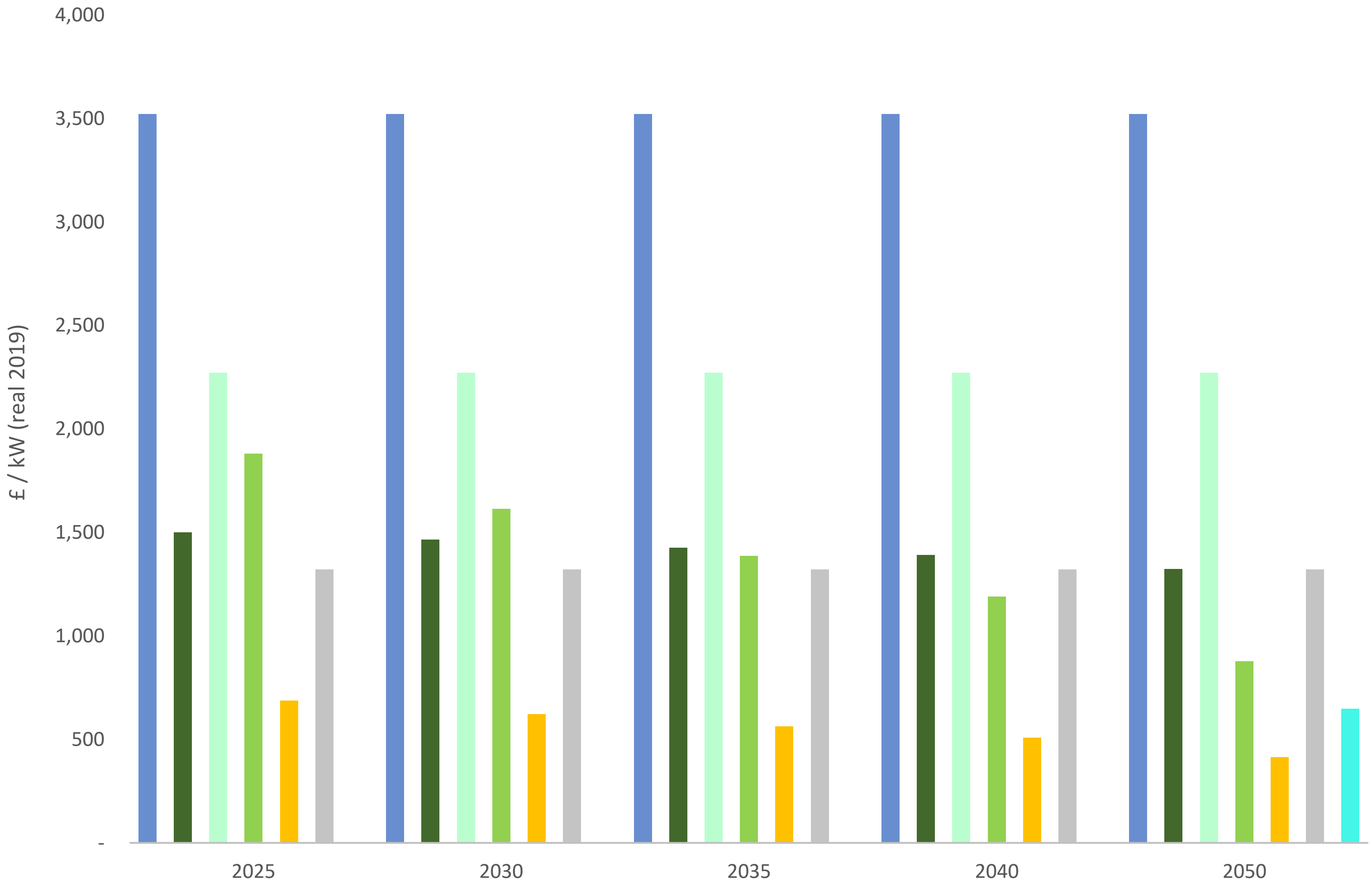
Cost Component	Cost inputs	
New Technology costs (Opex and Capex)	See new technology costs in this section	
Fuel Costs	See fuel costs in this section	
Interconnector Costs	See interconnector slide in this section	
Network Costs	Provided by MUA, see network slide in this section	
Technology types	**Value**	**Units**
**Fixed O&M Cost Existing Technology on IoM		
CCGT	24,500	£ Real 2019/MW/yr
Diesel	11,000	£ Real 2019/MW/yr
Hydro	11,700	£ Real 2019/MW/yr
EfW	139,460	£ Real 2019/MW/yr
**Variable O&M Cost Existing Technology on IoM		
CCGT	1	£/MWh
Diesel	7	£/MWh
Hydro	5	£/MWh
EfW	24	£/MWh

SOURCE: BEIS AND ARUP ANALYSIS*

In terms of capex, offshore wind sees the largest improvements, while solar PV (undistributed) and onshore wind see moderate reductions. No improvments expected for other technologies.

LEGEND

- ONSHORE WIND (>1MW)
- ONSHORE WIND (<1MW)
- OFFSHORE WIND
- BIOMASS
- HYDROGEN CCGT
- SOLAR (UNDISTRIBUTED)
- SOLAR (DISTRIBUTED)



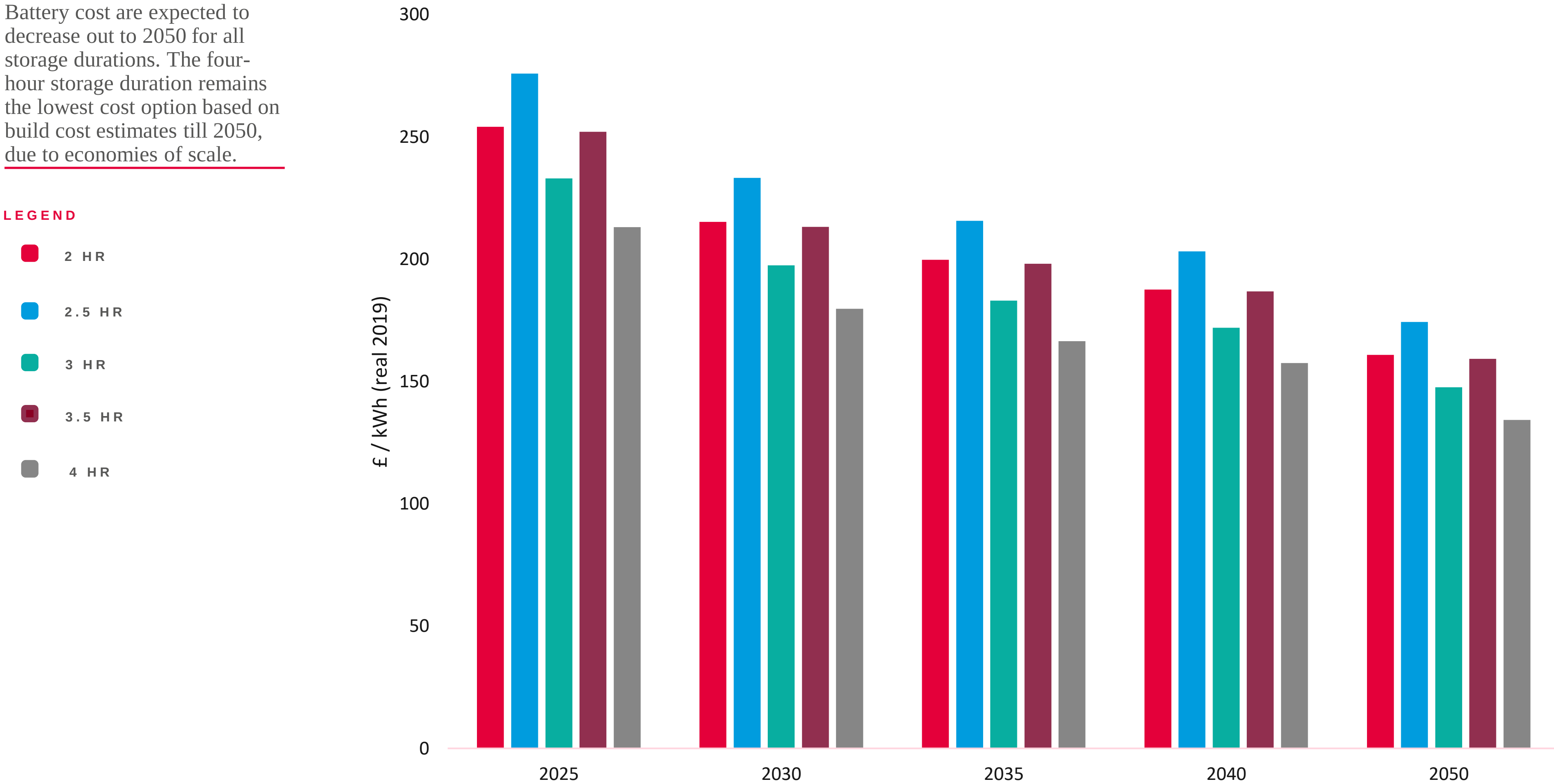
SOURCE: BEIS AND ARUP ANALYSIS

Hydrogen is competitive on capex terms against other renewable technologies, however when assessed on a total LCoE basis the fuel and carbon components make it much less competitive, additionally hydrogen only displayed in 2050, as blended quantities not high enough in GB grid until late post 2045, however this date could be earlier or later depending on how this technology develops.

Capex: includes pre-development and build cost.

Energy storage capex by energy storage duration

Battery cost are expected to decrease out to 2050 for all storage durations. The four-hour storage duration remains the lowest cost option based on build cost estimates till 2050, due to economies of scale.



SOURCE: NREL 2018 US UTILITY SCALE PHOTOVOLTAICS PLUS ENERGY STORAGE SYSTEM COSTS BENCHMARK (FOR 2018 COSTS), NREL COST PROJECTIONS FOR UTILITY-SCALE BATTERY STORAGE (FOR LEARNING RATES)

Other than offshore wind and solar PV, renewable technologies see no improvement in terms of fixed and variable operational and maintenance cost between now and 2050, according to BEIS.

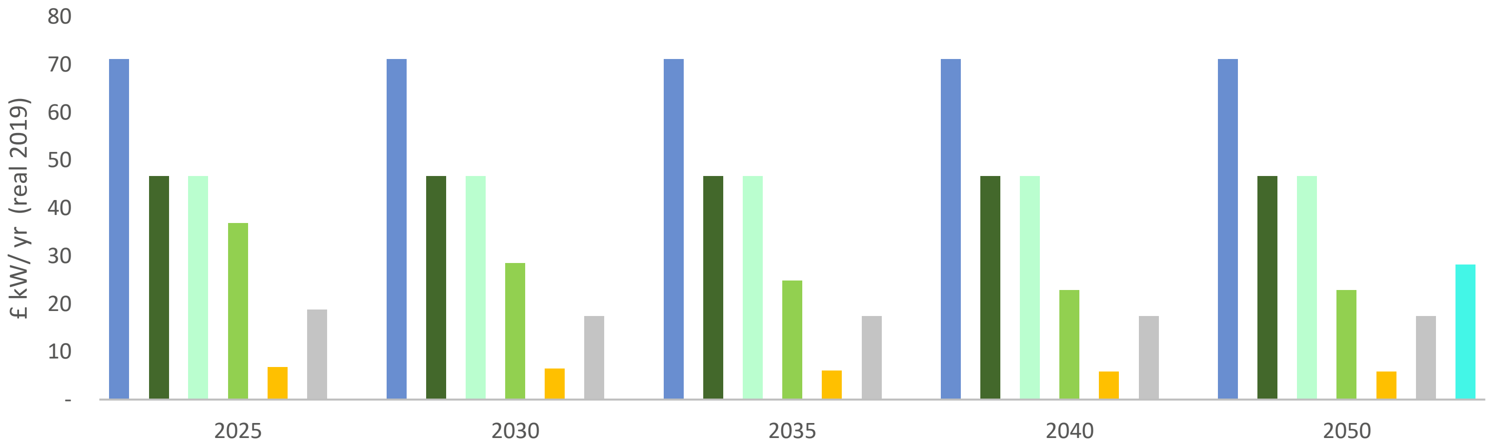
LEGEND

- ONSHORE WIND (>1MW)
- ONSHORE WIND (<1MW)
- OFFSHORE WIND
- BIOMASS
- HYDROGEN CCGT
- SOLAR (UNDISTRIBUTED)
- SOLAR (DISTRIBUTED)

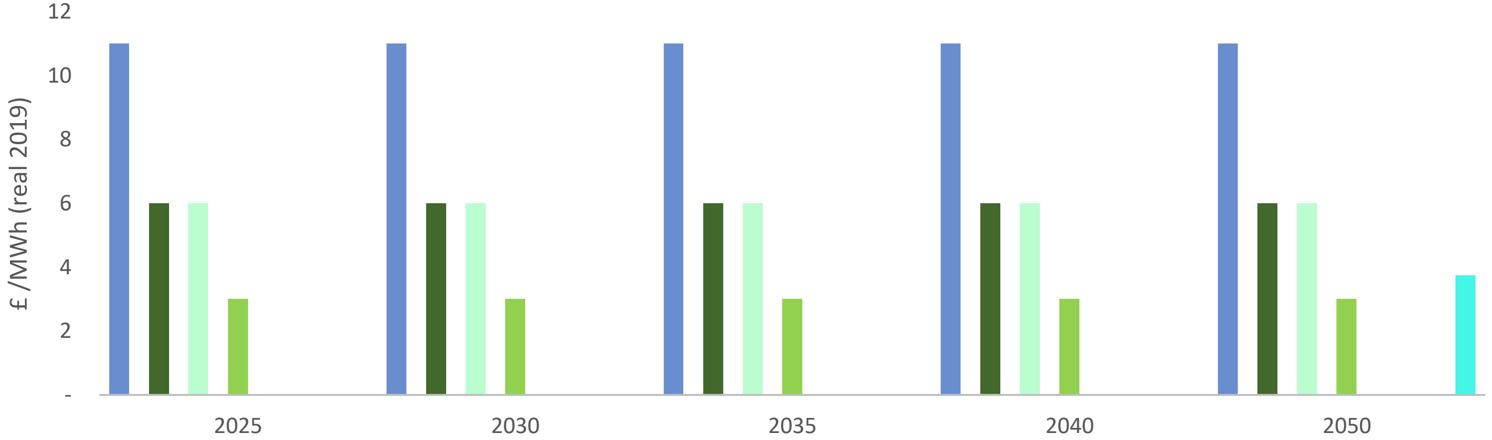
Hydrogen is competitive on opex terms against other renewable technologies, however when assessed on a total LCoE basis the fuel and carbon components make it much less competitive, additionally hydrogen only displayed in 2050, as blended quantities not high enough in GB grid until late post 2045, however this date could be earlier or later depending on how this technology develops.

Note: There are no variable O&M costs associated with solar generation.

EVOLUTION OF FIXED OPERATIONAL & MAINTENANCE COSTS



EVOLUTION OF VARIABLE OPERATIONAL & MAINTENANCE COSTS

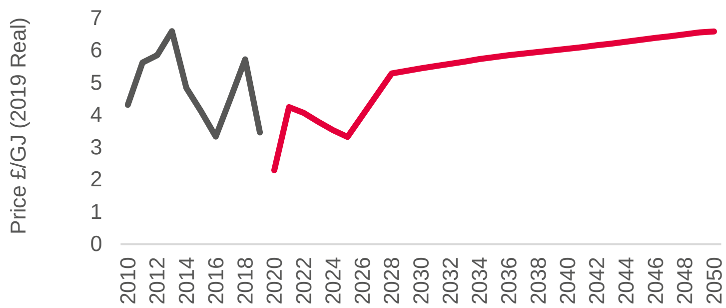


SOURCE: BEIS

G Fuel prices

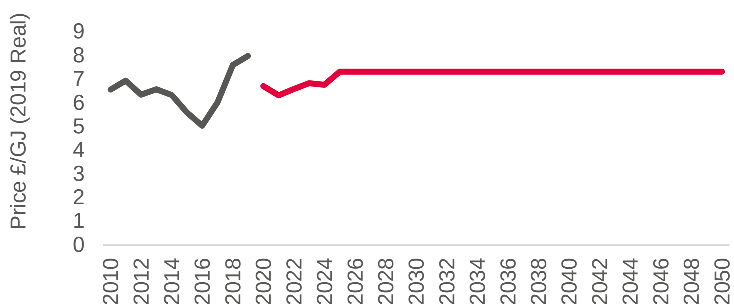
Commodity prices are one of the key inputs in Arup's model. Natural gas is expected to retain its prominence in the UK energy market. While there are limited market views on the future price of biomass, there are diverging views for future prices of gasoil and fuel oil. Green hydrogen is expected to lower the cost differential with blue hydrogen as these new technologies evolve.

NATURAL GAS PRICE EVOLUTION*



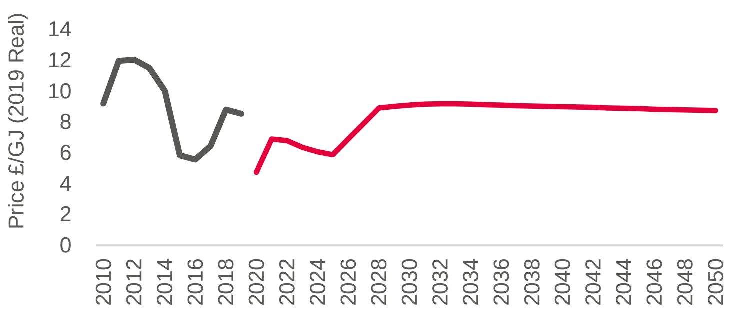
In the short term, our forecast is based on the historical forward curve, as it reflects all current information of players on the gas market. Our longer term forecasts are based on DECC and IEA views on future natural gas price development. By 2030, gas prices are set by the long run marginal cost of US LNG. Interpolation is used to create the price curve between long and short term.

WOOD PELLETS PRICE EVOLUTION



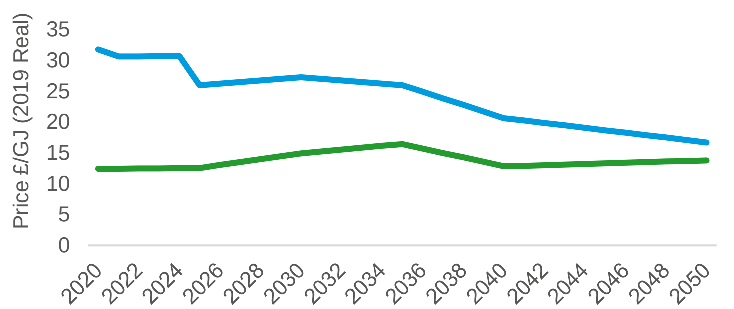
Arup used the 'forward curve' and extrapolated this to forecast the price of biomass up to 2050. We expect the influence of biomass to become more significant in the post-subsidy period (i.e., beyond 2028) when the commodity will be traded purely based on market dynamics.

BRENT CRUDE PRICE EVOLUTION



Our analysis indicates a strong historical correlation between the Brent crude price and the price of gasoil and fuel oil. To estimate the future price of gasoil and fuel oil, we have taken a combination of the forward curve and the National Grid ESO central forecasts for the Brent crude price.

HYDROGEN PRICE EVOLUTION



Arup's hydrogen price forecast is based on projected future hydrogen production costs in the UK and Europe in 5 yearly intervals, sampled from a number of sources. Arup has interpolated the results between the 5 year periods. Costs are currently very uncertain, and depend on a number of factors.

LEGEND

- Historical
- Central Forecast
- Blue Hydrogen
- Green Hydrogen

* The natural gas price when inputted into the electricity system model as a fuel cost for the CCGT has a 10% uplift applied to factor in local IoM cost inputs.

SOURCES: NATIONAL GRID ESO, BEIS, ICE NATURAL GAS FUTURES AND FES 2020 REPORT, ARGUS MEDIA FUTURES AND ARUP ANALYSIS

There is very little difference in terms of cost between AC and DC interconnectors. However, DC generally has lower electrical losses, failure rates and higher power quality than AC, but can deliver significantly fewer types of ancillary service.

NOTE

- Confidence range should be -5% to +15% .
- 103.7 KM is the current length of the IoM's existing 60MW interconnector. Arup have used this to assess cost implications so cost can be compared fairly and difference will be down to capacity and interconnector type rather than length, but also because identifying new interconnection sites is not the focus of this study.

INTERCONNECTOR OPEX AND CAPEX

Length	Capacity (MW)	Type	Opex per year (£ m 2019 Real)	Construction Cost* (£ m 2019 Real)
103.7 km	140	AC	0.70 - 0.85	120 – 148
103.7 km	140	DC	1.40 - 1.70	122 - 150
103.7 km	70	AC	0.50 - 0.60	103 - 124
103.7 km	70	DC	0.90 - 1.15	103 - 125
103.7 km	60	AC	0.50 - 0.60	102 - 124
103.7 km	60	DC	0.90 - 1.15	103 - 125
Refurbishment cost of the existing 60MW AC cable are estimated to equate to 7 - 9 m capex (Real 2019) and a 10% uplift in opex.				

- These are high level cost benchmarks based on Arup's experience. Each costs have high level ranges due to changing cost from various suppliers/contractors and depends on the project specific requirements. The final cost might be even lower and higher than the range provided, depending on the project specific conditions.
- The DC and AC projects have very similar costs at this length (~100km). This is because DCs have lower cable cost than AC, but higher substation compound costs due to converter additions. Lower cable and higher converter costs almost compensates each other around 100km threshold. However, it is possible there might be a higher cost difference within the range.
- O&M cost for within the Opex for DC projects is typically higher.
- ***Interconnector capital costs factor in the full system cost land to land (e.g one converter station is on the UK side and one on the IoM side).**

SOURCE: ARUP ANALYSIS

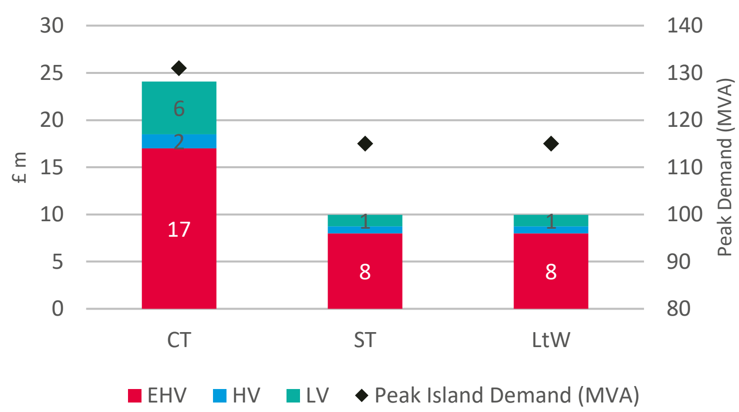
As demand increases and new generation is installed, the existing IoM network will need to be strengthened to accommodated this. Arup outline the costs and methodology behind these upgrades.

WHY NETWORK UPGRADES ARE REQUIRED

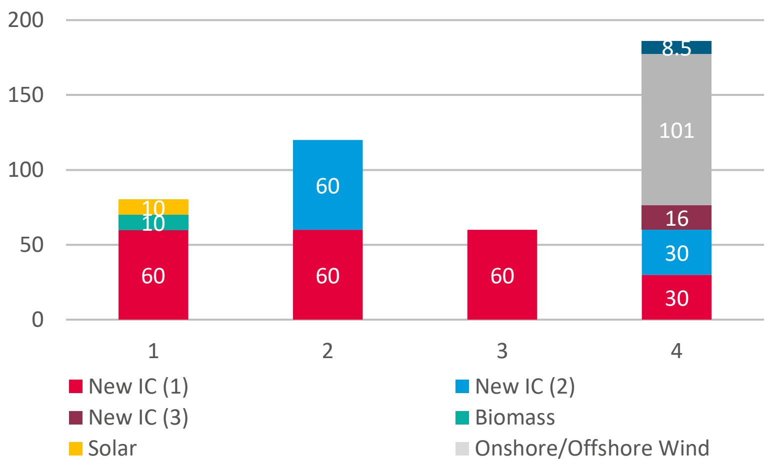
Electricity networks are designed to operate safely under worst-case peak demand conditions. As demand increases, the network needs to be strengthened to ensure security and quality of electricity supply to all customers.

New generation and interconnectors may also require network strengthening to ensure that generators can supply electricity to demand across the island. The network must be able to cope with maximum output from each generator although, in reality, not all generators would be operating at maximum output at the same time. This is due to the need for redundancy in generation.

NETWORK INVESTMENT BY 2050 FOR EACH DEMAND SCENARIO IN £M



NETWORK INVESTMENT BY 2050 FOR EACH GENERATION SCENARIO IN £M



SOURCE: MUA AND ARUP ANALYSIS

DEMAND RELATED NETWORK UPGRADE SUMMARY

- Network strengthening and investment requirements are highest for the CT scenario, which has the highest demand growth. Investment is required at all network voltage levels (EHV, HV and LV).
- Manx Utilities provided detailed power systems modelling results and investment estimates to support this assessment. Results were reviewed and verified by Arup.
- Non-network solutions e.g. demand side response based on price signals, can be implemented to help manage rapid growth in demand, providing more time to establish the need for large investments.
- Increased network visibility, through rollout of monitoring at lower voltage levels and smart metering, will also support continuous improvements in network planning & investment

GENERATION RELATED NETWORK UPGRADE SUMMARY

- Generation scenarios were developed based on meeting the needs of the CT demand scenario
- Network strengthening requirements depend on a number of factors such as where the generation/interconnector is being connected into the electricity network and the maximum output of the generation/interconnector.
- Network investment requirements are highest for S2, which requires the grid integration of two new 140MW interconnectors.
- Scenario 1 has a higher capacity of biomass and solar than the other generation scenarios. The total total size of biomass and solar generation capacity required explains the need for strengthening the network for for biomass and solar in S1, but not S2 and S3.
- Manx Utilities helped to identify transmission network upgrades and corresponding investment estimates for new generation and interconnectors.

Overall, scenario 4 is estimated to be the most expensive due to it having the largest installed capacity, driven by the desire for maximum on-island generation and highest resilience.

NOTE

The annual opex, capex, fuel and network costs have been discounted to provide a comparison of the overall costs of each scenario in NPV terms.

Discount rate of 5% has been use as advised by IoM.

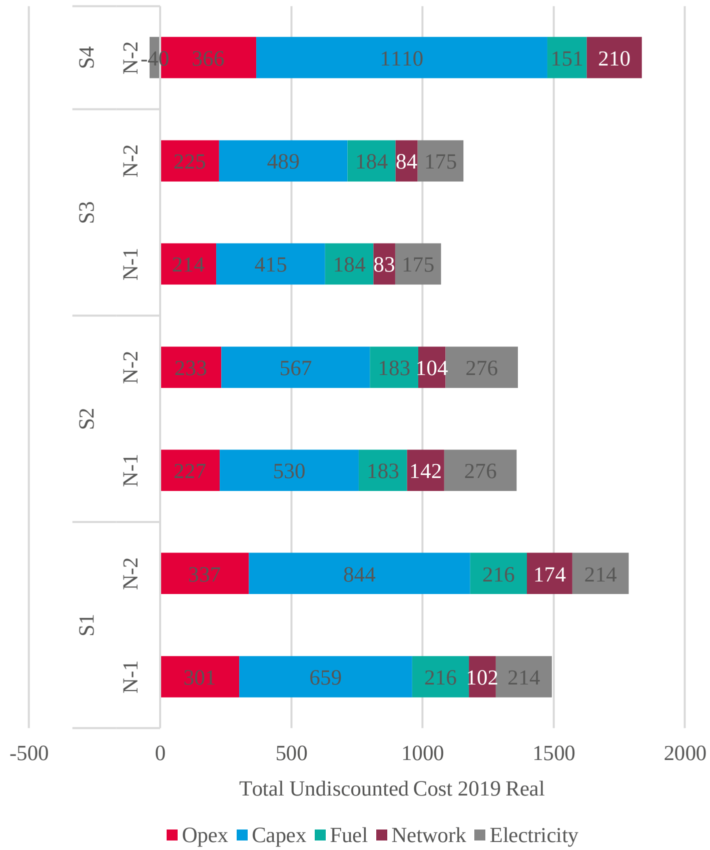
It is important to note this analysis is based on a high level indicative cost estimate to provide a cost comparison between scenarios.

KEY OBSERVATIONS

- The cost implications for a scenario are typically driven by the relationship between three key factors:
    - The level of resilience
    - The technology mix, including that required for resilience
    - The extent of on-island generation
- Scenario 4 has the maximum on-island generation. Consequently, it has the highest installed capacity across all scenarios, and is therefore estimated to be the most expensive.
- The higher the installed capacity, the more reinforcement is required on the network to accommodate the additional generating units.
- This further exacerbates the cost implications. As a consequence, the network implications cost are also estimated to be the highest for Scenario 4 compared to other scenarios.
- However, increasing on-island generation also minimises the need for importing energy from overseas markets (e.g., Great Britain). Consequently, the cost of importing energy is the lowest in Scenario 4.
- In summary, the benefits of increased on-island generation need to be weighed against the risk of importing power.
- Similarly, the benefits of increased resilience also need to be weighed against the potential risk and consequences of power outages.

Across scenario 1-3, the generation from biomass decreases over time as interconnector capacity increases. Subject to further analysis, there may be an opportunity to reduce overall costs across the four scenarios by brining forward the operation of new interconnectors. However, this will need to be weighed against potentially higher electricity import costs in earlier years.

ESTIMATED TOTAL COST BY SCENARIO AND RESILIENCE LEVEL (2021-2050)(£ MILLIONS), 2019 REAL



Net Present Cost
£898m
£606m
£552m
£681m
£663m
£887m
£707m

The electricity costs shown on the chart above are the net costs after accounting for both the estimated import and estimated export.

SOURCE: ARUP ANALYSIS

On a p/kWh basis, Scenario 4 is also estimated to be the most expensive.

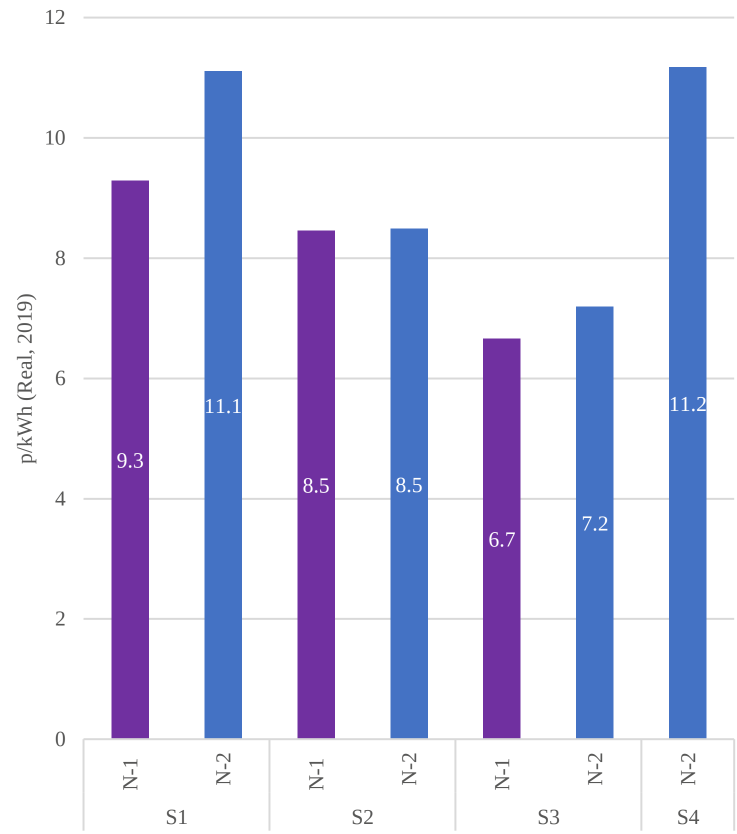
ASSUMPTIONS

- **Calculation methodology:** The estimated cost in p/kWh has been calculated by dividing the sum of the annual costs by the sum of the annual demand over the transition period from 2020-2050.
- The estimated annual demand is based on the consumer transformation scenario.
- The estimated annual costs, annual demand and the resulting cost in p/kWh presented on this page have not been discounted.

KEY POINTS:

- The estimated costs in p/kWh presented on this page for various scenarios are not consumer tariffs, i.e. these are not retail prices. Hence, these estimates do not reflect what consumers on the IoM will pay for the electricity in the future.
- It is likely that the retail price paid by end consumers will be higher. This is because the retail price is expected to include other items such as operational costs for MUA, potential taxes and levies and supplier margins.
- Additionally, the wholesale price estimates developed for these scenarios may also evolve over the long term with evolving supply and demand dynamics across the whole of north west Europe, and its interconnection with the GB market.
- Whilst this analysis gives a relative comparison of the costs of individual scenarios, the impact on end consumer price will depend on how the Isle of Man choses to fund and finance the transition over the long term.
- The IoM have estimated the cost for MUA at 5.4p/kWh, however Arup have not reviewed this calculation or validated this figure.

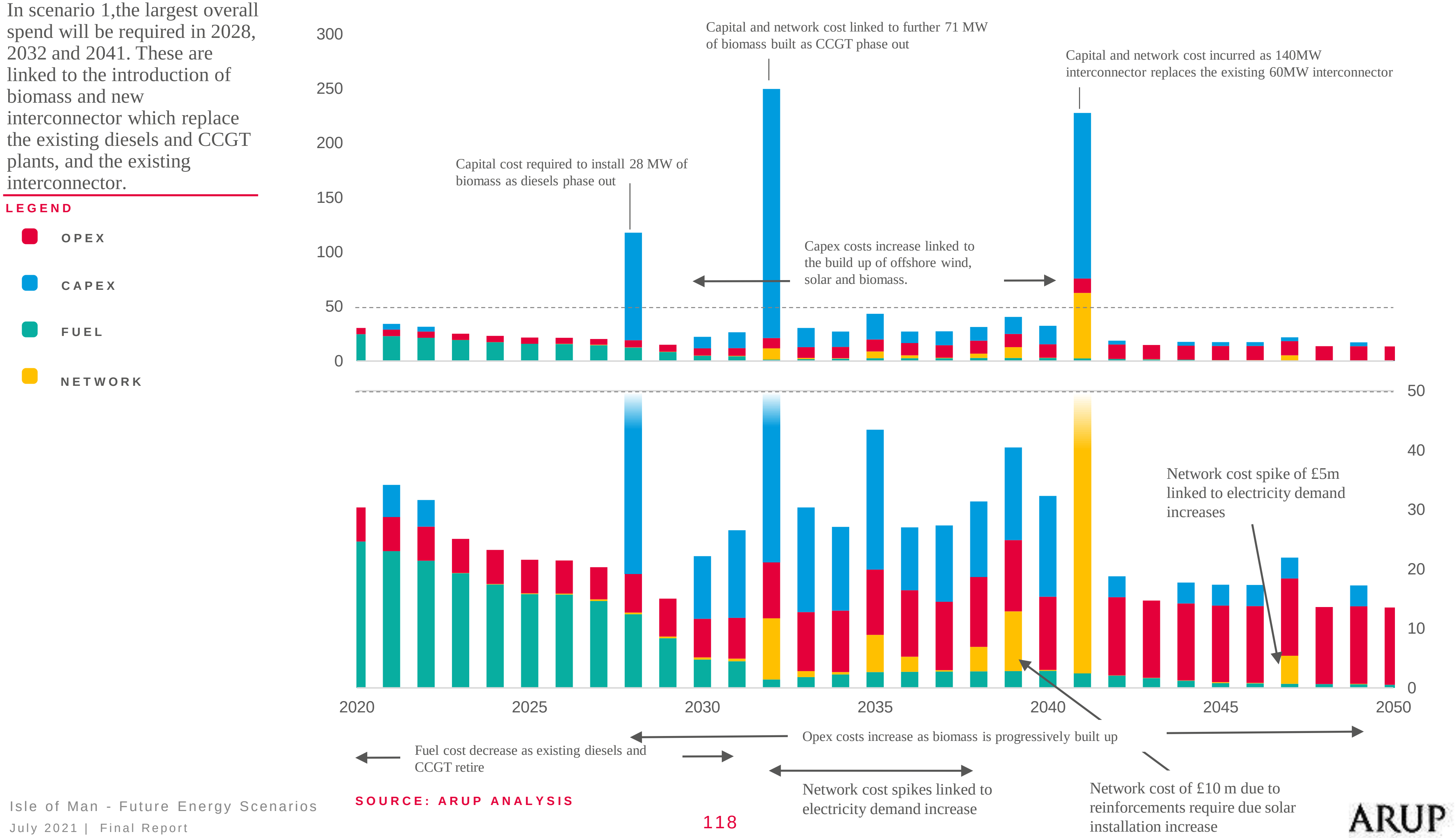
TOTAL ESTIMATED UNDISCOUNTED SCENARIO COSTS, P/KWH (REAL, 2019)



SOURCE: ARUP ANALYSIS

In scenario 1,the largest overall spend will be required in 2028, 2032 and 2041. These are linked to the introduction of biomass and new interconnector which replace the existing diesels and CCGT plants, and the existing interconnector.

COST EVOLUTION SCENARIO 1 (£m Real 2019)



SOURCE: ARUP ANALYSIS

Scenario 2 also see largest total spend in 2028, 2032 and 2041 for similar reasons. A new 140 MW interconnector is installed earlier in this scenario to replace the diesel generators, with biomass replacing the CCGT in 2032. An additional 140MW interconnector replaces the existing interconnector in 2041.

LEGEND

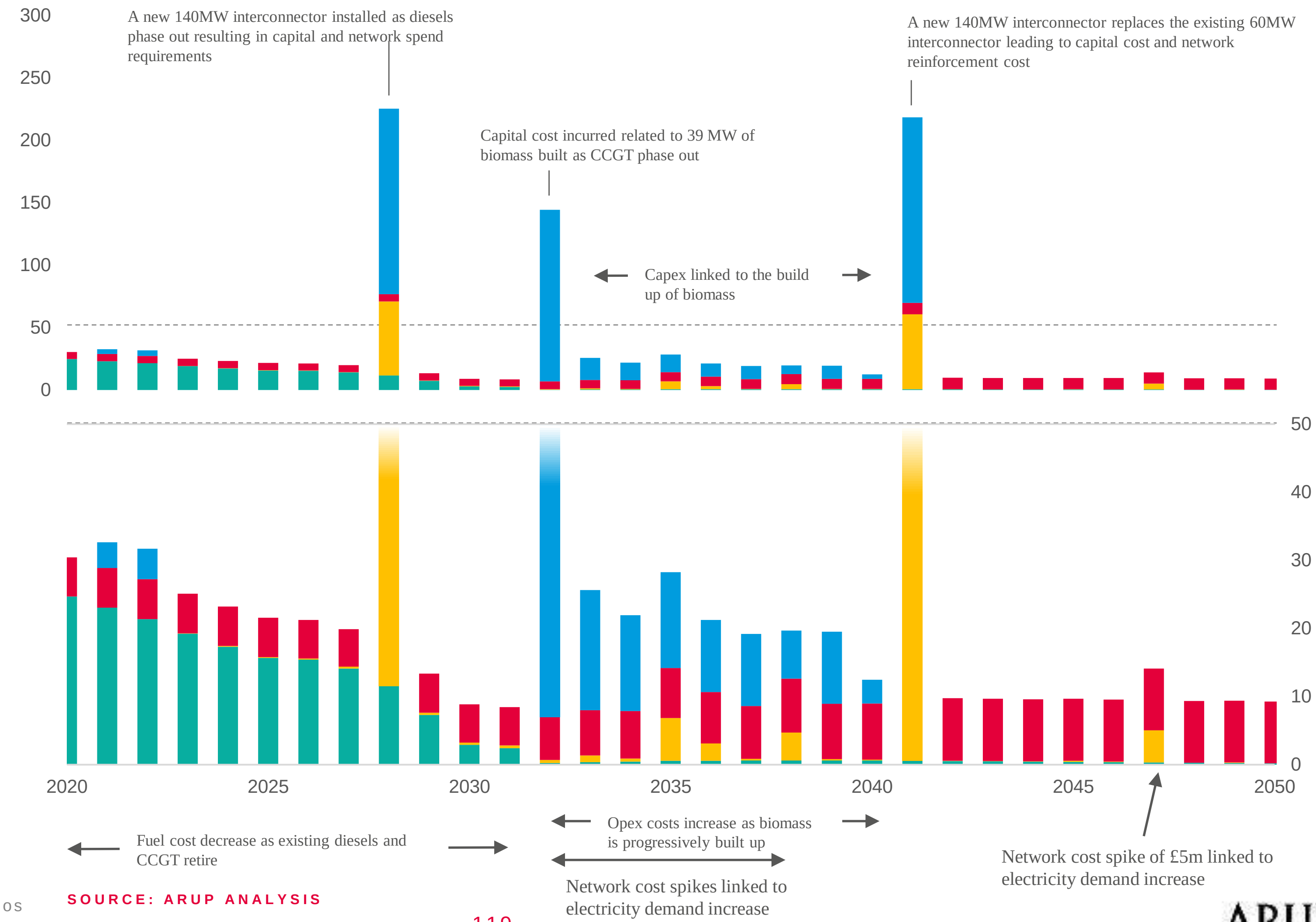
OPEX

CAPEX

FUEL

NETWORK

COST EVOLUTION SCENARIO 2 (£m Real 2019)



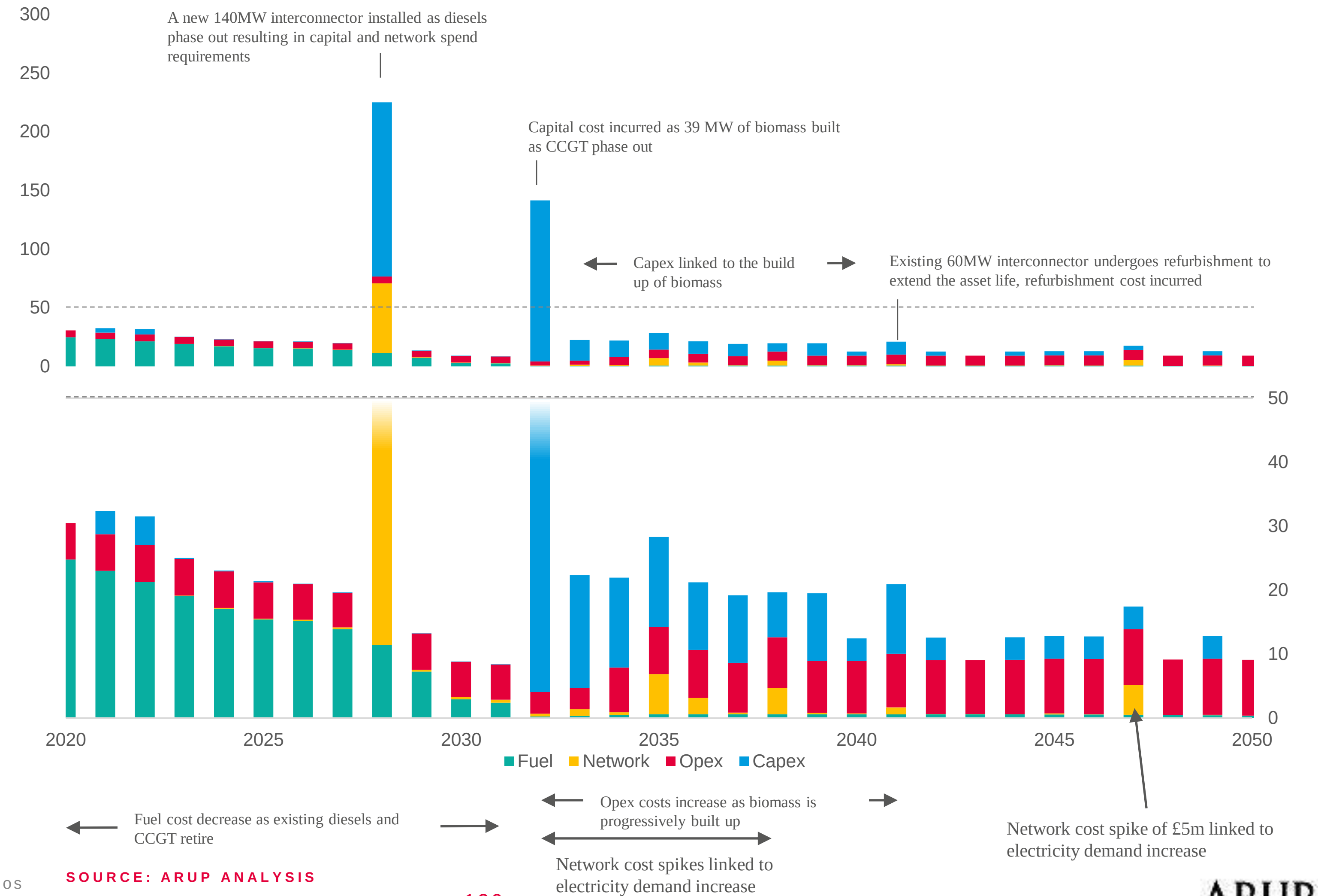
SOURCE: ARUP ANALYSIS

In Scenario 3, the largest total spend is in 2028 as retiring diesel generators are replaced by a new 140MW interconnector, and in 2032 when the existing CCGT is retired and replaced with 39MW of biomass. Unlike scenarios 1 and 2, the existing 60MW interconnector is refurbished in 2041 and extended out till at least 2050.

LEGEND

- OPEX
- CAPEX
- FUEL
- NETWORK

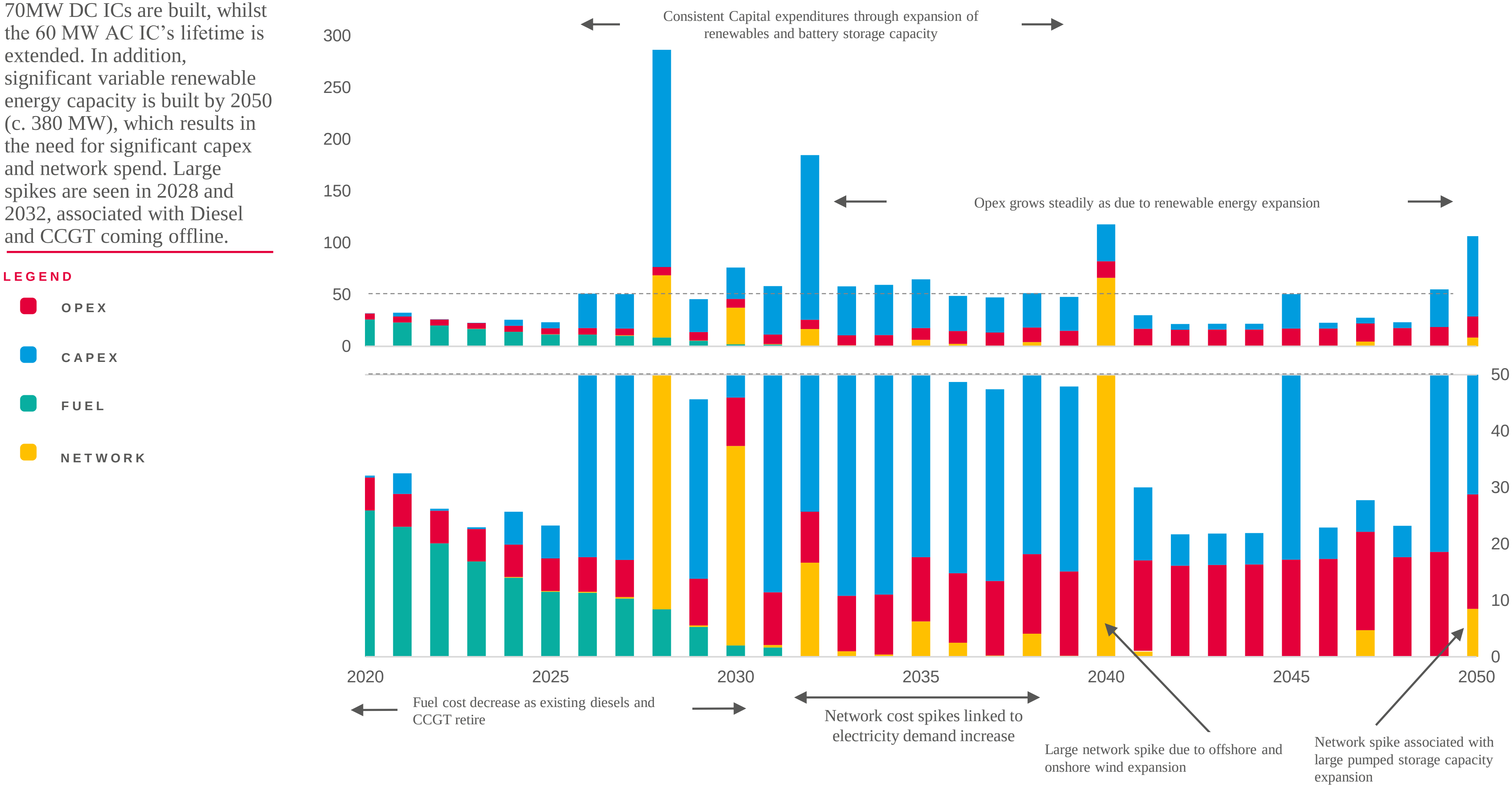
COST EVOLUTION SCENARIO 3 (£m Real 2019)



SOURCE: ARUP ANALYSIS

In Scenario 4, three additional 70MW DC ICs are built, whilst the 60 MW AC IC's lifetime is extended. In addition, significant variable renewable energy capacity is built by 2050 (c. 380 MW), which results in the need for significant capex and network spend. Large spikes are seen in 2028 and 2032, associated with Diesel and CCGT coming offline.

COST EVOLUTION SCENARIO 3 (£m Real 2019)



SOURCE: ARUP ANALYSIS

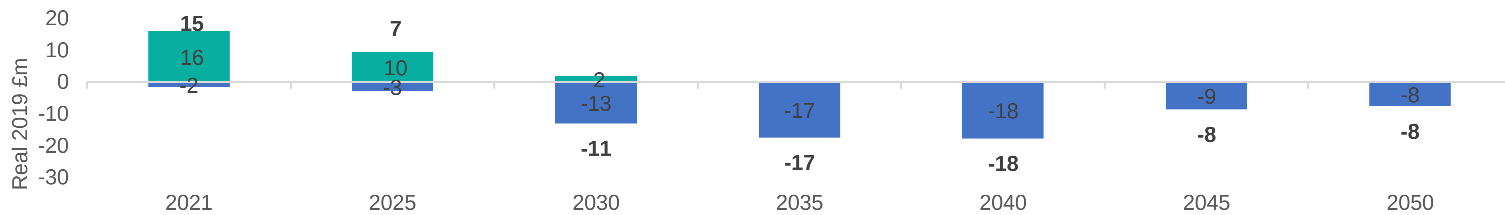
Electricity export revenue and import cost comparison

There is little difference in the export revenue/import costs across Scenarios 1-3. Scenario 4 has comparatively less imports and shows the potential for net exports, albeit a small amount, by 2050.

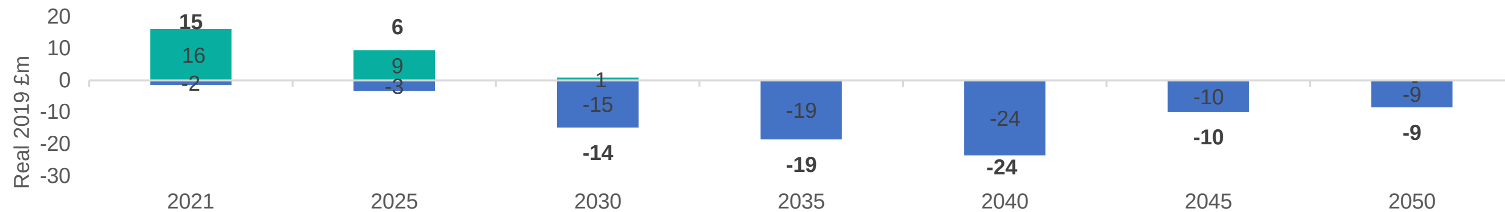
LEGEND

- EXPORT REVENUE
- IMPORT COST

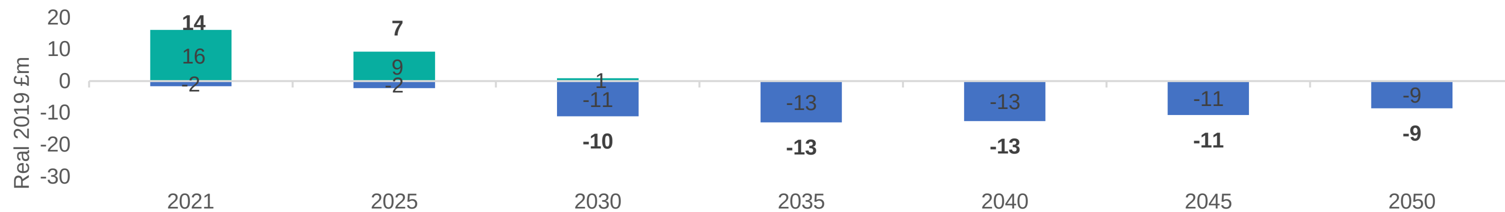
SCEANRIO 1 REVENUE / COST (REAL 2019 £M)



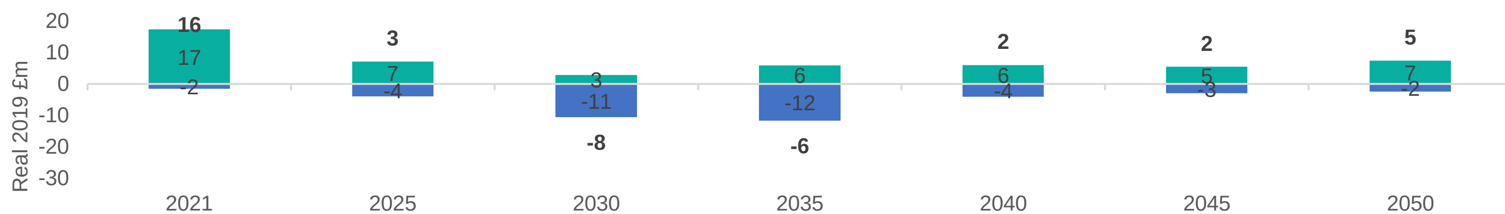
SCEANRIO 2 REVENUE / COST (REAL 2019 £M)



SCEANRIO 3 REVENUE / COST (REAL 2019 £M)



SCEANRIO 4 REVENUE / COST (REAL 2019 £M)



SOURCE: ARUP ANALYSIS

Financial Considerations

Scenario cost comparisons: summary results

Across all four scenarios, the most significant capital expenditure is incurred between 2028-2032 driven by the retirement of existing diesel and CCGT plants. Additional interconnector capex is also incurred in scenarios 1 and 2 in early 2040s.

Definitions:

Import: Electricity costs from importing electricity from GB to IoM.

Export: Electricity revenues from excess electricity exported to GB from the IoM. Export revenues are shown as negative value.

Note: Column and row totals may not align due to rounding.

COST EVOLUTION SCENARIO 1 (£m 2019 Real)

	2020	'21	'22	'23	'24	'25	'26	'27	'28	'29	'30	'31	'32	'33	'34	'35	'36	'37	'38	'39	'40	'41	'42	'43	'44	'45	'46	'47	'48	'49	'50	Total
Opex	6	6	6	6	6	6	6	5	7	6	6	7	9	10	10	11	11	11	12	12	12	13	13	13	13	13	13	13	13	13	13	**301**
Capex	-	5	4	-	-	-	-	-	99	-	11	15	229	18	14	24	11	13	13	16	17	152	4	-	4	4	4	4	-	4	-	**659**
Fuel	25	23	21	19	17	16	16	15	12	8	5	4	1	2	2	3	3	3	3	3	3	2	2	2	1	1	1	1	1	1	1	**216**
Import	1	2	2	2	3	3	5	7	9	11	13	14	15	16	17	17	17	17	18	18	18	16	14	12	10	9	8	8	8	8	8	**324**
Export	(18)	(16)	(14)	(13)	(11)	(10)	(8)	(6)	(5)	(3)	(2)	(2)	-	-	-	(0)	(0)	(0)	(0)	(0)	-	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	**(109)**
Network	-	-	-	0	0	0	0	0	0	0	0	0	10	1	0	6	3	0	4	10	0	60	0	0	0	0	0	5	-	0	-	**102**
Total	14	20	19	14	15	15	18	21	122	23	33	39	264	46	44	61	44	45	49	58	50	244	33	27	28	26	26	30	22	25	21	**1493**

COST EVOLUTION SCENARIO 2 (£m 2019 Real)

	2020	'21	'22	'23	'24	'25	'26	'27	'28	'29	'30	'31	'32	'33	'34	'35	'36	'37	'38	'39	'40	'41	'42	'43	'44	'45	'46	'47	'48	'49	'50	Total
Opex	6	6	6	6	6	6	6	6	6	6	6	6	6	7	7	7	8	8	8	8	8	9	9	9	9	9	9	9	9	9	9	**227**
Capex	-	4	4	-	-	-	-	-	148	-	-	-	137	18	14	14	11	11	7	11	4	148	-	-	-	-	-	-	-	-	-	**530**
Fuel	25	23	21	19	17	16	15	14	12	7	3	2	0	0	0	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	**183**
Import	1	2	2	2	3	3	6	8	10	13	15	16	16	17	18	19	20	21	22	23	24	21	18	15	13	10	10	9	9	9	9	**380**
Export	(18)	(16)	(14)	(13)	(11)	(9)	(8)	(6)	(4)	(3)	(1)	(1)	-	-	-	-	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-	**(104)**
Network	-	-	-	0	0	0	0	0	59	0	0	0	0	1	0	6	3	0	4	0	0	60	0	0	0	0	0	5	-	0	-	**142**
Total	14	18	19	15	15	15	19	22	231	23	23	23	161	43	40	47	41	40	41	42	36	239	28	25	22	20	19	24	18	18	18	**1359**

COST EVOLUTION SCENARIO 3 (£m 2019 Real)

	2020	'21	'22	'23	'24	'25	'26	'27	'28	'29	'30	'31	'32	'33	'34	'35	'36	'37	'38	'39	'40	'41	'42	'43	'44	'45	'46	'47	'48	'49	'50	Total
Opex	6	6	6	6	6	6	6	5	6	6	6	6	3	3	7	7	8	8	8	8	8	8	8	8	9	9	9	9	9	9	9	**214**
Capex	-	4	4	0	0	0	0	0	149	0	0	0	137	18	14	14	11	11	7	11	4	11	4	-	4	4	4	4	-	4	-	**415**
Fuel	25	23	21	19	17	15	15	14	11	7	3	2	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	**184**
Import	1	2	2	2	2	2	4	6	8	9	11	11	12	12	13	13	13	13	13	13	13	12	12	11	11	11	10	10	9	9	9	**278**
Export	(18)	(16)	(14)	(13)	(11)	(9)	(8)	(6)	(4)	(3)	(1)	(1)	-	-	-	-	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-	**(103)**
Network	-	-	-	0	0	0	0	0	59	0	0	0	0	1	0	6	3	0	4	0	0	1	0	0	0	0	0	5	-	0	-	**83**
Total	14	18	19	14	14	14	17	20	228	20	19	19	153	35	35	41	34	32	32	32	25	33	24	21	24	23	23	27	19	22	18	**1071**

COST EVOLUTION SCENARIO 4 (£m 2019 Real)

	2020	'21	'22	'23	'24	'25	'26	'27	'28	'29	'30	'31	'32	'33	'34	'35	'36	'37	'38	'39	'40	'41	'42	'43	'44	'45	'46	'47	'48	'49	'50	Total
Opex	6	6	6	6	6	6	6	7	8	8	9	9	9	10	11	11	12	13	14	15	16	16	16	16	16	17	17	17	18	19	20	**366**
Capex	-	4	0	0	6	6	33	33	252	32	30	47	159	47	48	47	34	34	33	33	36	13	6	6	6	33	6	6	6	36	78	**1110**
Fuel	25	23	20	17	14	12	11	10	8	5	2	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**151**
Import	1	2	2	3	3	4	5	7	8	9	11	11	11	11	11	12	10	9	7	6	4	4	4	3	3	3	3	3	3	3	2	**177**
Export	(18)	(17)	(15)	(12)	(10)	(7)	(6)	(5)	(5)	(4)	(3)	(3)	(4)	(5)	(5)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(5)	(6)	(6)	(7)	(7)	(7)	**(217)**
Network	-	-	-	0	0	0	0	0	60	0	35	0	17	1	0	6	3	0	4	0	66	1	0	0	0	0	0	5	-	0	9	**210**
Total	14	17	14	14	19	20	50	52	332	51	84	66	192	65	66	71	53	50	53	48	116	28	20	20	20	48	20	24	19	51	102	**1796**

SOURCE: ARUP ANALYSIS

Export and import electricity wholesale pricing

IoM exploits arbitrage opportunity to export when GB market price is higher (subject to having enough local generation to meet its load) and to import when the situation is reversed.

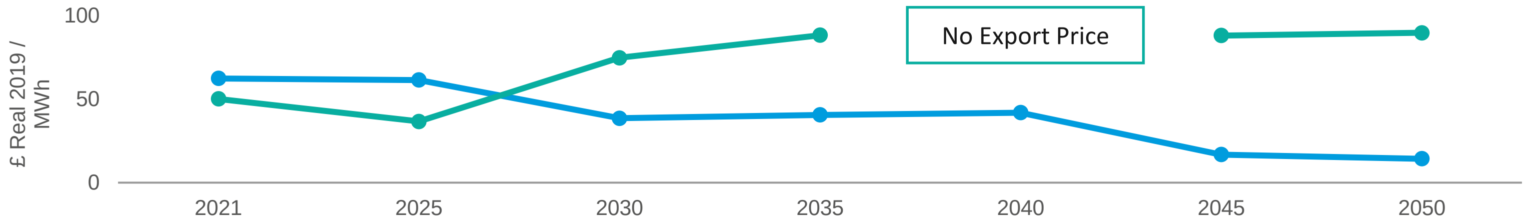
LEGEND

- WEIGHTED VOLUME EXPORT PRICE
- WEIGHTED VOLUME IMPORT PRICE

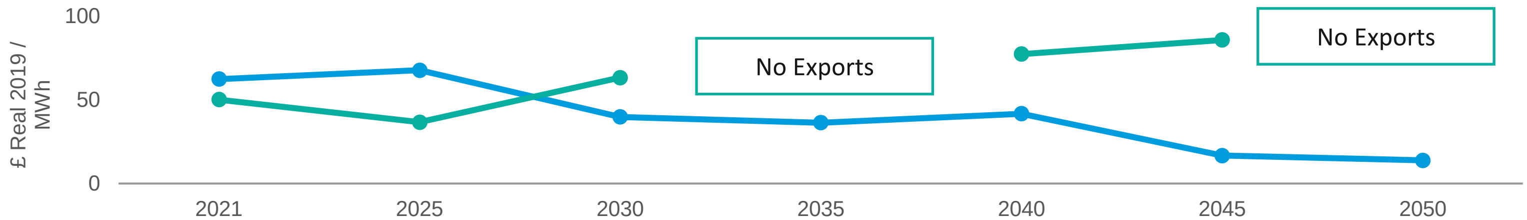
The prices presented reflect the import and export price in scenarios 1-3 only when IoM is importing or exporting and do not represent the average annual wholesale price.

The information on this chart is not intended to show the profitability or loss associated with exporting/importing energy for each scenario. This analysis solely shows the estimated price/cost of export/import.

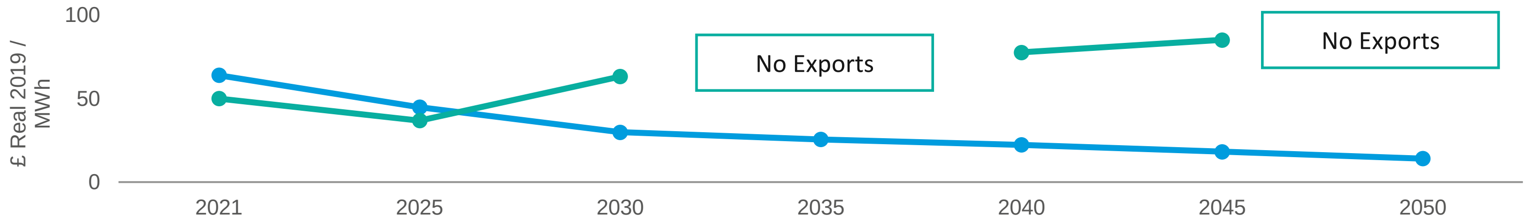
SCEANRIO 1 EXPORT / IMPORT PRICE (REAL 2019 £M)



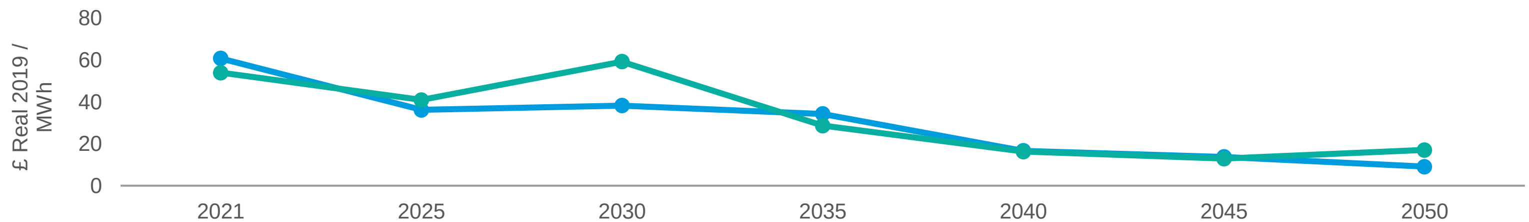
SCEANRIO 2 EXPORT / IMPORT PRICE (REAL 2019 £M)



SCEANRIO 3 EXPORT / IMPORT PRICE (REAL 2019 £M)



SCEANRIO 4 EXPORT / IMPORT PRICE (REAL 2019 £M)



SOURCE: ARUP ANALYSIS

8. CONCLUSIONS AND NEXT STEPS

Given the nature of the energy trilemma, each scenario scores differently for the individual aspects of the trilemma. Nevertheless, all scenarios ensure security of supply and reach net zero by 2050.

LEGEND AND NOTES

Scenarios

Best

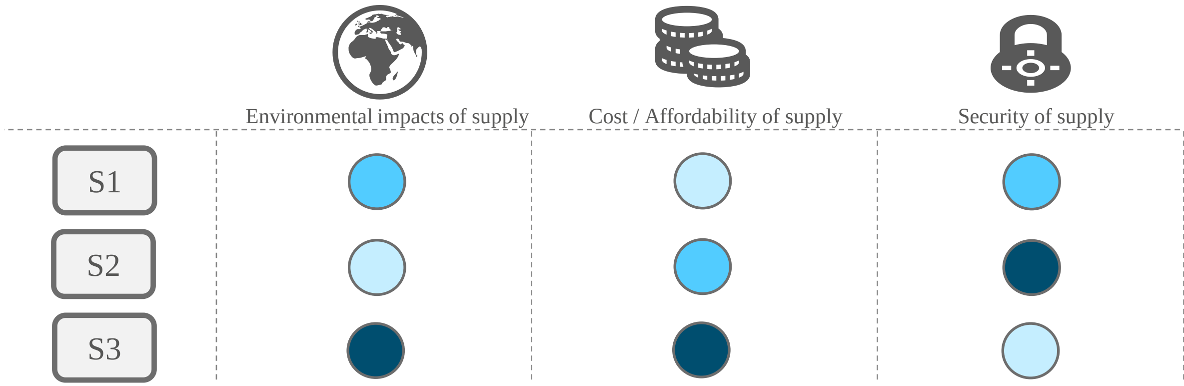
Middle

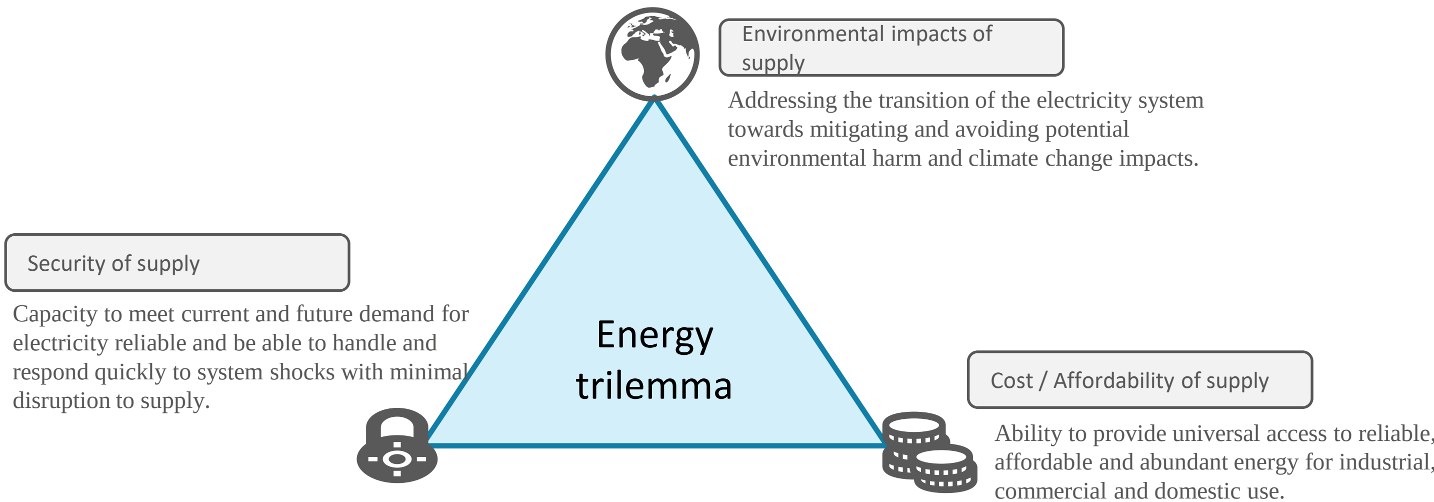
Worst

***Note- best, middle and worst is relative to each other**

This relative high level scoring is based on the scenarios as currently presented in the future energy scenarios section, but if changes were made, such as splitting interconnector, this may change the relative positions.

RELATIVE SCENARIO SCORES IN TERMS OF ENERGY TRILEMMA*

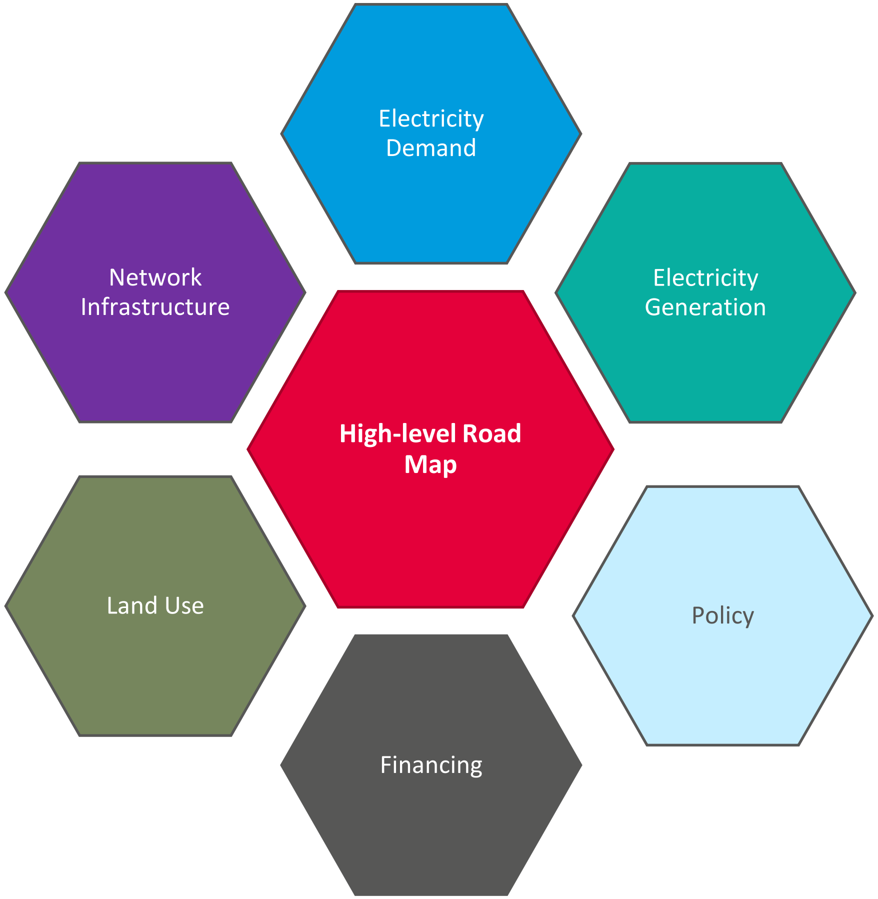




SOURCE: ARUP ANALYSIS; WORLD ENERGY COUNCIL

A high-level road map focusing on the six key areas, highlighted adjacent, has been developed to help transition the island's electricity network to achieve net zero emissions by 2050.

KEY FOCUS AREAS OF THE HIGH-LEVEL ROAD MAP



High level Road map until 2035: Electricity demand

To enable refinement of the demand evolution scenarios, IoM should continue improving data collection and finalise heating, transport and energy efficiency strategies.

Electricity Demand

IoM climate targets

2035 - 75% generation from renewable or carbon neutral sources
2050 - Net-Zero greenhouse gas emissions

Electricity Demand	Immediate short term (0-5 years)	Medium term (5-10 years)	Long term (10-15 years)
Data gathering	• Improve electricity consumption data gathering through smart meter rollout. • This will enable better insights on consumption patterns by key user groups including residential, industrial and commercial and transport-related use of electricity.		
Heating Strategy	• Finalise and implement policy changes associated with heating strategy (e.g., launch incentives for supporting transition away from fossil-fuel based heating).	• Depending on outcome of heating strategy, installation of heat pumps starts to take effect and electricity demand increases.	
Building and appliance efficiency	• Finalise and implement policy changes associated with building and appliance efficiency standards (e.g., potential building regulation or energy performance certification (EPC) changes).	• New-builds and appliances become more energy efficient and start to lower electricity demand	
Transport	• Finalise and implement policy changes associated with 'green mobility' (e.g., phase-out of petrol and diesel cars)	• EV penetration increases on the island. • Rollout of charging infrastructure (public and private) • Finalise smart charging tariffs and policies (subject to technological evolution)	• EVs dominate majority of private vehicles. • Smart charging becomes increasingly common.

SOURCE: ARUP ANALYSIS

High level Road map until 2035: Electricity generation

IoM should also review and finalise its resilience requirements, and undertake detailed assessment to finalise the requirements for new interconnector(s).

* The existing diesel generators and CCGT retire by end of 2027 and 2031 respectively – this is based on information provided by the client team and is reflected in the model. Options for extending the asset life of these generators, and operating them at reduced capacity should be considered. This will enable IoM to delay certain investment decisions, whilst continuing to reduce emissions from electricity generation.

Electricity Generation

IoM climate targets

2035 - 75% generation from renewable or carbon neutral sources
2050 - Net-Zero greenhouse gas emissions

	Immediate short term (0-5 years)		Medium term (5-10 years)	Long term (10-15 years)
Data gathering	• Improve electricity generation data gathering for better assessment of emissions and actual generation capacity. • Prepare and keep up-to-date a detailed emissions inventory for each generation plant to inform future assessments.			
Resilience	• Undertake an evidence-based assessment to determine the required level of resilience in the future system. • This should include cost benefit analysis and clear recommendation on required level of resilience (e.g., N-1, N-2 etc.) • Assess and identify a suitable pool of technologies (e.g., biomass, biogas, biodiesel, interconnector, renewable and storage etc.) required to achieve the necessary resilience level. • This should include an assessment of fuel availability, infrastructure requirements, processing, transportation and storage requirements and rules for offsetting and importing of fuel.			
Future Energy Scenarios	• Update existing scenarios or generate additional scenarios, based on the outcome of the resilience study.	• Perform further detailed analysis of selected generation scenarios to assess detailed costs, funding and financing requirements, and environmental implications. • Quantify the on-island size of the ancillary service requirement, including primary but secondary and tertiary.	• Start engaging technology providers and delivery partners. • Develop outline and strategic business cases for near-term solutions (e.g., site identification, concept design / FEED, high-level EIA for the development of solar PV farm, onshore / offshore wind or interconnector. • New renewable generation begins to be installed on the IoM and fossil fuels begin to phase out.*	
Interconn-ection	• Undertake a full feasibility study and cost benefit analysis to decide on type (AC vs DC), size and location of the interconnector. • Engage relevant parties (e.g., National Grid) to inform the detailed feasibility study and finalise technical, commercial and contractual parameters.		• Commence interconnector planning, design, construction and commissioning activities.	• Interconnector operational. • Assess the need for second interconnector.

SOURCE: ARUP ANALYSIS

High level Road map until 2035: Policy

A number of key policy initiatives will be required to enable the transition from the existing fossil fuel generation system to a net zero system by 2050.

IoM climate targets

2035 - 75% generation from renewable or carbon neutral sources
2050 - Net-Zero greenhouse gas emissions

Policy | Immediate short term (0-5 years) | Medium term (5-10 years) | Long term (10-15 years)

Heating Strategy

- Finalise heating strategy, assessing potential synergies with Future Energy Scenarios.
- Identify initiatives required to implement heating strategy (e.g., subsidies for alternative technologies such as heat pumps)

Building and appliance efficiency

- Finalise policy and legislation for future building and appliance efficiency standards (e.g., EPC requirements).
- New appliance and building efficiency standards come into force, with incentive support where necessary.

Transport

- Finalise transport strategy (EV and hydrogen)
- Draft legislation and policies for phase-out of petrol and diesel vehicles.
- Identify mechanism(s) required to support uptake of EVs and wider implementation of transport strategy

- Implement recommendations from the findings of transport strategy.
- Rollout of public EV charging stations.
- Assess the role of hydrogen in the island's future transport system and related policy and infrastructure requirements. .

- Phase out the sale of new petrol and diesel vehicles comes into force.
- First few hydrogen refuelling stations built to service public transport and HGVs etc.

Waste

- Finalise future waste strategy and waste management policies.
- Asses future waste volumes available to the EfW and implications for the Future Energy Scenarios.

Clean Air Act

- Draft air quality legislation targeting reduction of non-carbon emissions such as NOx and SOx.

Carbon

- Introduction of carbon tax to discourage investment in new fossil fuel based technologies and incentivise phase out of existing fossil fuels.
- Introduce carbon budgets to ensure transition to net zero is on-track.

- Carbon tax comes into force.
- First carbon budget milestone met, and budget for subsequent period is finalised.

Electricity Act

- Amend the Electricity Act (if necessary) to ensure it can enable energy transition and is aligned with the Climate Change Bill (e.g., review and remedy the conflict between needing to generate from cheapest source vs transitioning to net zero).

Electricity market

- Electricity market structure review in lieu of attracting private funding or public and private partnerships to support deployment of new technologies.

Renewable incentives

- Conduct a renewable policy support study to assess if government support mechanisms are required enable future generation (e.g., support for on-island production of biomaterial).

SOURCE: ARUP ANALYSIS

High level Road map until 2035: Financing and Land Use

The IoM should also identify and ring-fence funding and financing sources for short to medium term actions. Additionally, it should review land use and associated policies in lieu of the net zero transition.

IoM climate targets

2035 - 75% generation from renewable or carbon neutral sources
2050 - Net-Zero greenhouse gas emissions

	Immediate short term (0-5 years)	Medium term (5-10 years)	Long term (10-15 years)
Financing	• Identify options for ownership and operation of new generation assets. • Accordingly, determine options for financing and funding of new generation assets. • Undertake more detailed financing and funding assessment for short and medium term actions.	• Identify financing and funding sources • Develop strategic and outline business cases as necessary • Ring-fence short, medium and long-term requirements as appropriate.	• Review and adjust long-term requirements.
Land use	• Identify suitable land areas for new generation assets • Identify land areas for biomaterial production and processing. • Update long-term land development plans reflecting the energy transition.	• Commence procurement, planning and enabling works to accommodate new generation and network-related assets associated with short to medium term actions. • Commence afforestation and land restoration where feasible.	• Commence biomaterial production and storage

SOURCE: ARUP ANALYSIS

Conclusions and Next Steps

High level Road map until 2035: Network infrastructure

A number of key actions associated with resilience, smart solutions, technology innovation and data gathering have also been identified to support the evolution of the IoM's electricity network.

Network Infrastructure

IoM climate targets

2035 - 75% generation from renewable or carbon neutral sources
2050 - Net-Zero greenhouse gas emissions

Immediate short term (0-5 years) | Medium term (5-10 years) | Long term (10-15 years)

Resilience

- Assess the risk of climate change for assets and network resilience.
- Identify measures to mitigate the key risks.

- Update system wide stability studies.
- Monitor the ability of technology developments for power electronics to enable greater contribution to system operational performance and resilience.

Network Infrastruc-ture

- Develop improved tools for decision making under uncertainty as energy system changes.
- Increase frequency of network planning as demand and generation mix evolve more rapidly.

- Investigate potential for smart/flexibility solutions on the IoM and understand implications for investment enablers.

- Coordinate increasing load related and asset age/condition related investment to improve efficiency, where possible.
- Review effectiveness of various reinforcement measures and smart /flexibility solutions from a planning, investment and operational perspective.
- Develop a sophisticated operational and control room strategy as system operation becomes more complex.

Data

- Continue roll out of smart meters to support improved data gathering.

- Develop digitalisation strategy that supports integration of increasing monitoring data from the distribution network into network planning, asset management and network operation.

SOURCE: ARUP ANALYSIS

Arup has identified seven key recommendations to inform the transition of the island's electricity network, and to support decision making over the longer term (1 of 2)

1 Assess future system resilience requirements

- The resilience level required for the future electricity system needs to be reviewed and agreed, as it has significant impacts on the amount and type of installed electricity generation capacity required in the future.

2 Identify suitable pool of technologies required to meet future resilience

- Based on current discussions with the IoM Climate Change Transformation Team, it is understood that the island will need to have a dispatchable and carbon neutral electricity source to provide the necessary level of resilience by 2050.
- For the purpose of this study and as agreed with the IoM team, biomass and interconnectors have been implemented in the model as the most suitable dispatchable and carbon neutral sources. However, biodiesel, biogas or other suitable biomaterial can be considered as alternatives.
- When making this decision the feasibility of each option needs to be carefully assessed, such as understanding on island fuel availability, import rules and infrastructure requirements such as fuel processing facilities, transportation and storage.
- For biogas, as an example, farming subsides may need to be introduced so farmers grow the crop, large areas of land will need to be identified for this purpose and anaerobic digestion plants will need to be built, as well as gas storage and transport systems.

3 Undertake detailed interconnector feasibility study

- Based on the outcome of this study and discussions with IoM, adding more interconnection is a no-regret/low-regret solution.
- It will give the IoM greater resilience capacity, and is a compatible solution with any further generation installations that may take place on the IoM.
- It also provides greater long-term flexibility in deciding between on-island generation vs import of electricity.
- IoM should perform a full feasibility study and cost benefit analysis to decide on type and size of interconnection that should be pursued.
- IoM should also engage with relevant parties (e.g., National Grid) to inform the procurement of a new interconnector.

SOURCE: ARUP ANALYSIS

Arup has identified seven key recommendations to inform the transition of the island's electricity network, and to support decision making over the longer term (2 of 2)

4 Finalise waste strategy

- The Island's waste strategy needs to be developed. It has implication for future waste volumes accessible to the EfW.
- Arup's understanding is that the island's waste management strategy is striving for a reduction in waste volumes – this is consistent with the general trends and policy direction across the UK and Europe. We therefore envisage EfW generation to decline in the future.
- If the EfW generation capacity is maintained at its current level, or increased, in the future, then this may help with some reduction in other on-island renewable generation. However, the reduction is envisaged to be minimal, given the EfW is a small 5MW plant, operating at c.60% capacity.
- Additionally, it allows certain investment decisions to be delayed. However, this is dependent on the future waste volumes and the associated biogenic content.

5 Finalise heating strategy

- The heating strategy will have significant impacts on the island's electricity demand, which will ultimately impact amount of generation capacity required in the future. Therefore, finalising this strategy is a key step before other non-interconnector technology development on the island is considered.
- The IoM should also evaluate during this process whether there are any potential synergies with future the electricity generation that can be leveraged or any foreseen issues between heating and electricity supply (e.g biomass fuel constraints).

6 Finalise transport strategy

- The evolution of transport on the IoM is a key driver of demand and therefore the level of future generation required. The transport strategy needs to be finalised to inform the evolution of the electricity demand. This strategy also needs to address requirements, if any, for phasing out of ICE (petrol and diesel) vehicles and incentives required to support the up-take of EVs. Additionally, it needs to present pathways for alternative fuels for public transport and larger vehicles.

7 Introduce policy changes

- A number of policy drivers including clean air act, carbon tax, incentives for energy efficiency and uptake of alternative fuel vehicles need to be developed to enable the transition.

SOURCE: ARUP ANALYSIS

APPENDIX

The UK has implemented a number of laws and regulations to address harmful pollutants being emitted into the air. Similar initiatives may be necessary on the Isle of Man to compliment the Climate Bill.

UK CLEAN AIR POLICY

- The clean air act was introduced in the UK in 1956 to tackle air pollution problems highlighted by ‘lethal fog’ which descended on London for a period of c. one week. The act has been amended multiple times to incorporate new regulations (e.g.,1993).
- Essentially the clean air act sets a number of specific regulations for releasing emissions from combustion in the industrial, commercial, residential and transport sectors.
- The wide range of regulations largely cover the control of smoke emissions, height of chimneys, smoke-free zones and the content and composition of motor fuels. It is actually an offense, punishable by conviction to break the conditions of the clean air act.
- Since the act was introduced a number of other air quality improvement measures have been introduced to further address air quality, specifically addressing emissions of particular pollutants such as NOx and Sox, such as:
    - Part VI of the Environment Act 1995.
    - The 2008 Ambient Air Quality Directive (2008/50/EC).
    - Air Quality Standards Regulations 2010.

SOURCE: DEFRA AND MID DEVON DISTRICT COUNCIL

Background and Historical carbon pricing, The EU ETS, €/tCO2 Real 2020

Carbon (CO2) prices are currently trading near all time highs. The Market Stability Reserve (MSR) introduced in 2019 has resulted in scarcity by curbing fresh auction supply. IoM may want to introduce similar carbon tax.

EU ETS BACKGROUND

The EU Emissions Trading Scheme (EU ETS) is one of the largest cap and trade schemes in the world, covering CO2 emissions from large installations and aviation.

Market participants in the sectors covered by the EU ETS are required to at the end of each year submit allowances (EUAs) to cover their CO2 emissions. Trading of allowance is encouraged so the least cost of abatement of CO2 for the whole of the EU is discovered.

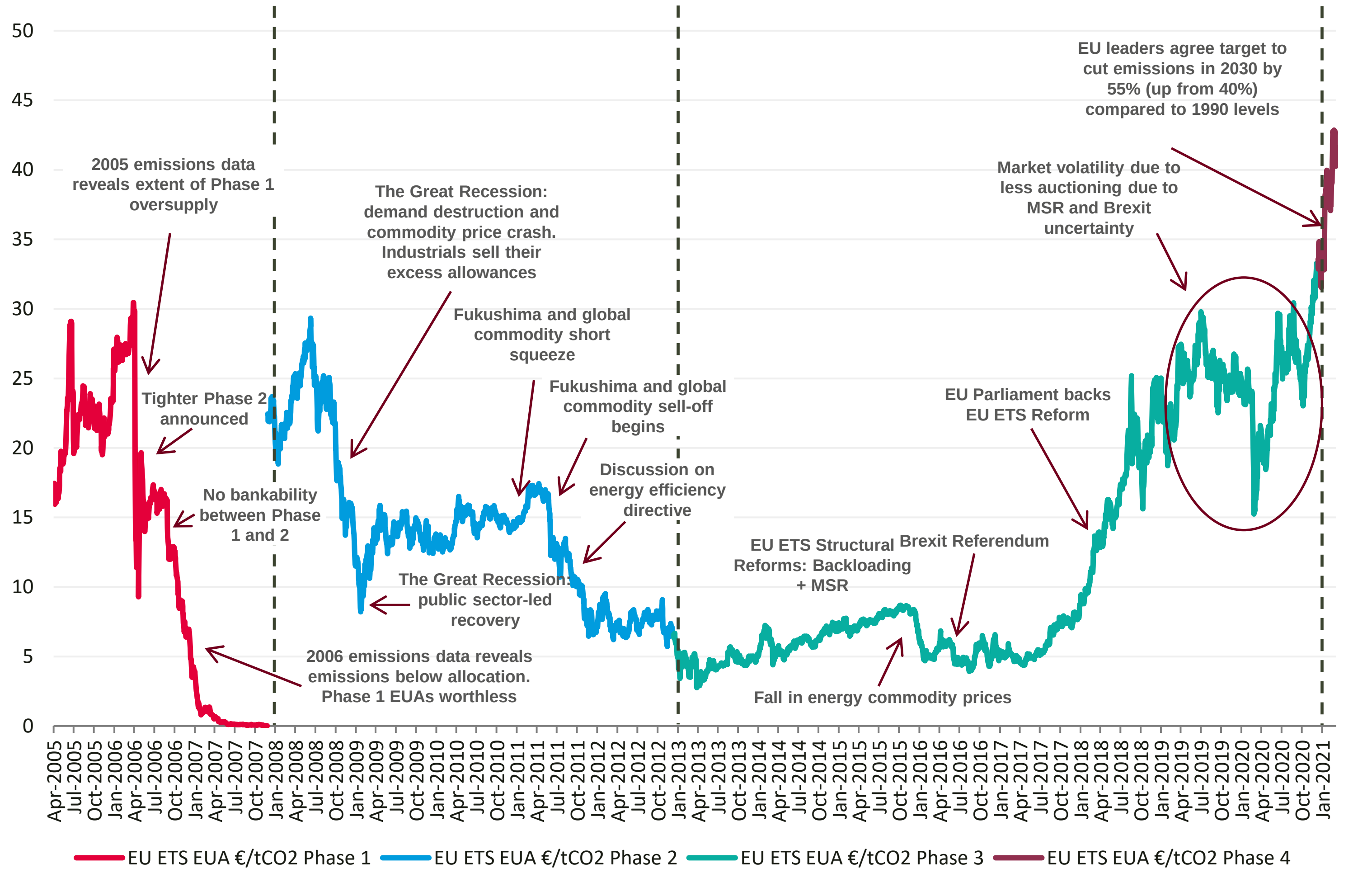
The UK as of the 1st of January 2021 sits outside of the EU ETS and is currently developing its own Emissions Trading Scheme, UK ETS.

Phase I – running for three years from 2005 to 2007, this was a essentially a trial period, allowing market participants, largely those in the power sector

Phase II – running for five years from 2008 to 2012

Phase III – running for eight years from 2013 to 2020

Phase IV – running from ten years from 2021 to 2030



SOURCE: THE INTERCONTINETAL EXCHANGE (ICE), ARUP ANALYSIS

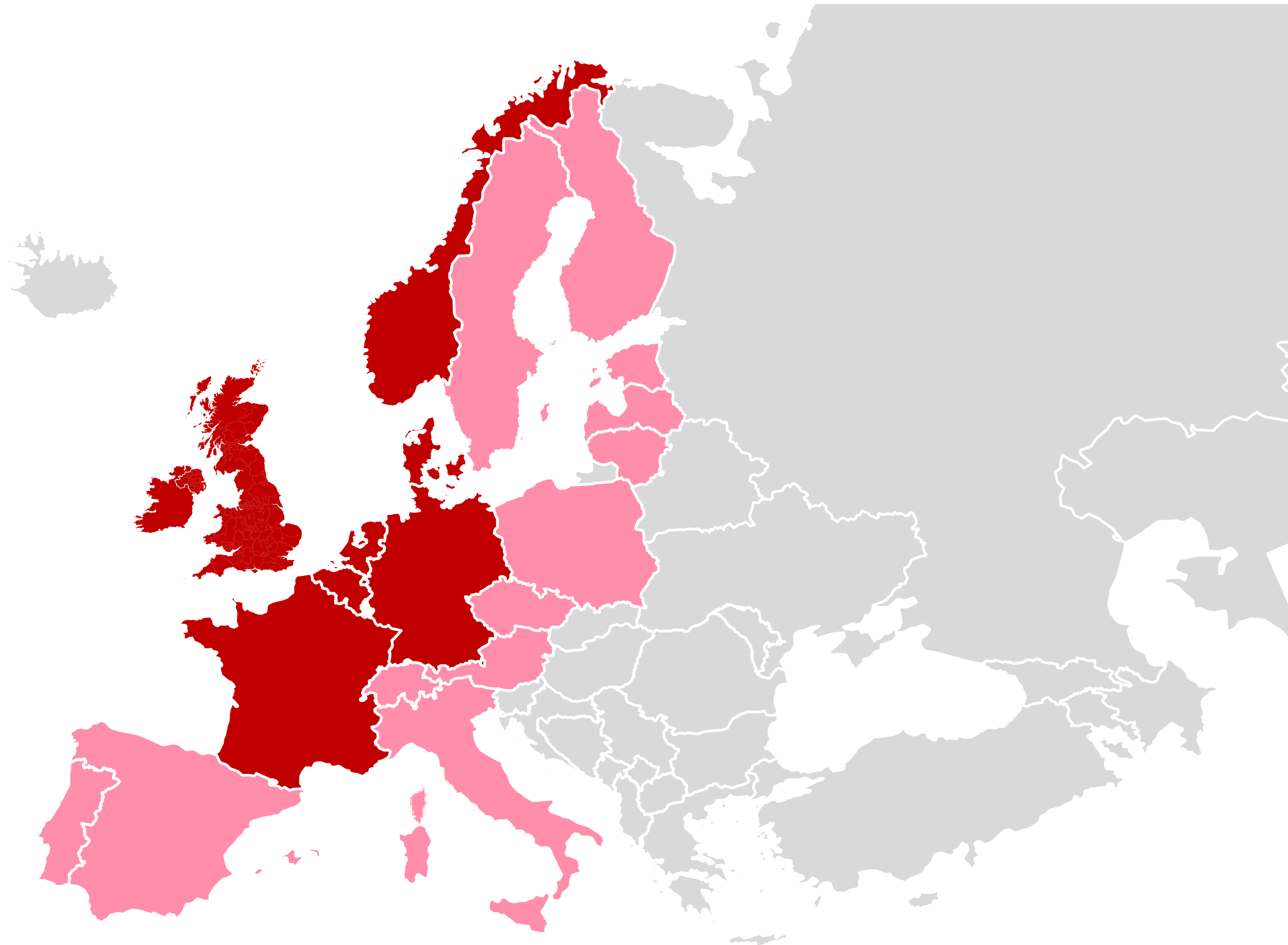
Arup has built its European power market model to cover Western and some of Central Europe. The model allows us to investigate the impact of different factors on the development of the European power sector.

OUR MARKET MODELLING

The core focus of the model has been on the Isle of Man and GB power markets. It has also included a number of North-western European including: Belgium, Germany, Denmark, France, Island of Ireland, Holland and Norway.

For the purposes of modelling the IoM power market, Arup has constrained interconnector volumes between GB and Europe to be consistent with the consumer transformation National Grid FES scenario, but has not constrained interconnector volumes between IoM and GB.

ARUP'S POWER MARKET MODELLING COVERAGE MAP



SOURCE: ARUP

Modelled in this study

Covered by Arup's power model

Delphi market modelling: Delphi integrated modelling framework and map

Arup's Delphi modelling framework fosters excellence in power infrastructure and policy appraisal. It facilitates understanding of asset's commercial feasibility in the technical, regulatory and market context.

WHAT IS DELPHI?

Delphi is Arup's framework for understanding complex infrastructure projects & policies.

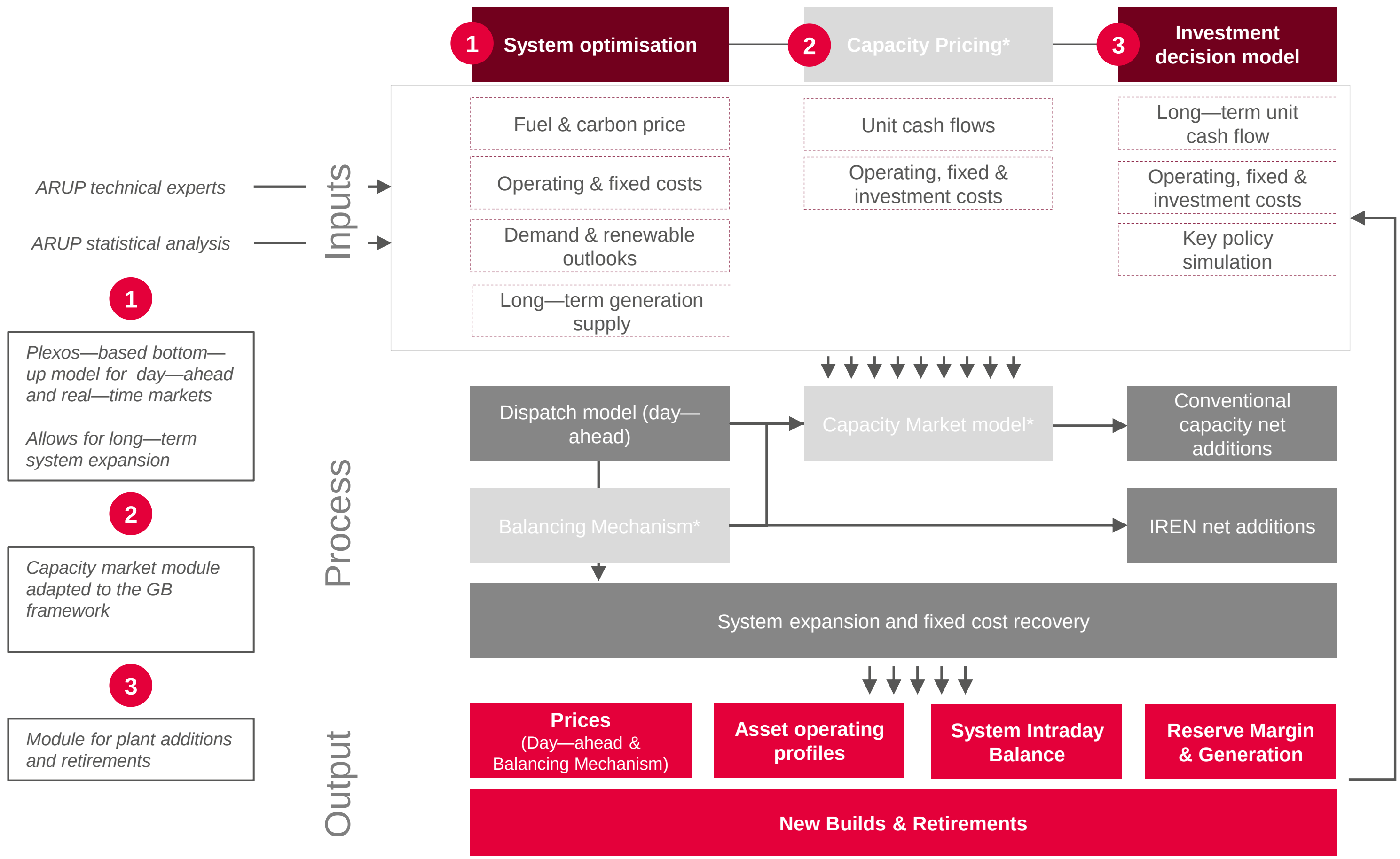
Delphi is a modelling framework comprising optimisation, capacity pricing and system expansion modules. It can be applied to assets and markets globally.

Delphi is built in Energy Exemplar's market leading PLEXOS Market Simulation Software.

The modelling is rooted in economic principals of power markets and structured around unit commitment optimisation, price formation and long-term system expansion.

Delphi is integrated in nature, which allows us to model the links between international electricity markets, in addition to the causality between short-term market dynamics and fixed cost recovery.

DELPHI FRAMEWORK MAP: INDIVIDUAL COMPONENTS ARE INTERLINKED TO PROVIDE A COHERENT MARKET OUTLOOK

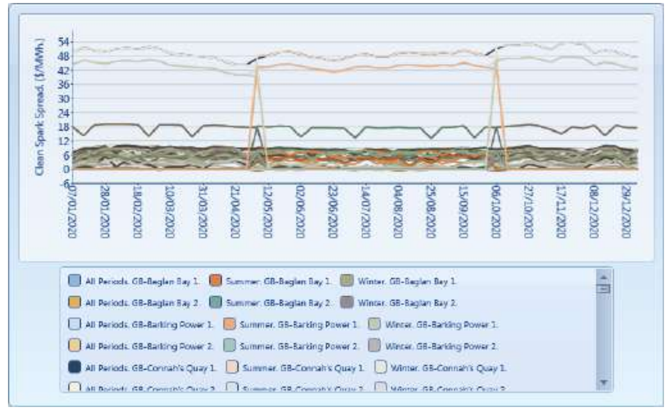


SOURCE: ARUP

*Capacity pricing, capacity market model & balancing mechanism have not been used for purposes of modelling IoM Power Market

PLEXOS is a leading power market simulation software used for forecasting and assessing market dynamics, and informing investment decisions.

EXAMPLES OF PLEXOS AT WORK



PLEXOS AT WORK

PLEXOS is only one part of Delphi comprising:

- Dispatch and balancing market model;
- Balancing markets can be co-optimised with the dispatch model;
- Stochastic modelling capability;
- High time granularity (hourly);
- Modelling of any gas and power market in the world;
- Dynamic integration of interconnected markets;
- Several ways to model long term expansion and thus the capacity market income.
- Arup is using the latest production version of PLEXOS as of January 2021 – version 8.3

SOURCE: ARUP ANALYSIS

A.7

Appendix

Simulation and Analysis tools in PLEXOS

The PLEXOS energy market model has a number of different simulation and analysis tools which are used to model the future energy scenarios on the IoM.

Each phase occurs sequentially with the prior phase feeding inputs into subsequent phases.

There are a number of functionality/granularity options available to us to manage the 'problem size' and balance the resolution against time it takes to get a result

LT Plan – Optimal Investment/Retirement Plan for the Power System

PASA – Projected Assessment of System Adequacy

MT – Energy Storage Optimisation and Multi-Step Constraints Decomposition

ST – Generator Commitment and Generator Dispatch Level

Phase	Primary Function & Analysis	Main Output	Horizon
LT Schedule	Generation/Transmission Expansion, Resource Planning, Project viability, Investment analysis, renewable integration	Builds and Retirements	10-50 years
PASA	System Outage Scheduling, (Convergent or classical) Monte-Carlo random outages, Regional capacity share	Maintenance Schedule & reliability indices	1-10 years
MT Schedule	MT schedule decomposes medium-term constraints and objectives into a set of equivalent short-term constraints and objectives which can be applied in the ST schedule (e.g., Energy storage/ fuel supply/emission constraints)	Operating schedule pass	1 year
ST Schedule	Day/Week/Hour market simulation, optimal bidding, CCGT analysis, ST risk management, Energy & Ancillary Service optimisation, OPF	Detailed Chronological Operation	Sub-Hourly– 1 week

SOURCE: ENERGY EXEMPLAR

ARUP

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