Cap and Floor Window 3 and OHA pilot scheme Needs Case Assessment

ESO modelling report

March 2024

Contents

1. Executive Summary

Ofgem has developed the cap and floor regime to encourage investment in electricity interconnectors. Ofgem's third cap and floor application window ran from 1st September 2022 to 10th January 2023. Alongside this Ofgem ran an Offshore Hybrid Asset (OHA) application period from 1st September 2022 to 31st October 2022. In total nine projects are being assessed as part of the Needs Case Assessment for the Initial Project Assessment for the third window and the OHA pilot scheme.

Ofgem and ARUP developed a new needs case assessment framework for Cap and Floor Window 3 and the OHA pilot scheme. The assessment features a broad set of impact categories, including socio-economic welfare, system operability, constraint costs (balancing market impacts), decarbonisation, security of supply and hard to monetise impacts.

This analysis that the ESO has undertaken is broken down into five main assessment areas. These are:

- **Constraint costs** – quantifying the potential impact of the Window 3 and OHA pilot projects on constraints on the network. Also referred to as balancing market impacts.
- **Frequency Response** – the potential impact of the projects on system frequency.
- **Reactive Power** – the potential impact on system voltage.
- **Restoration** – the potential impact of the projects on restoring power to the system in the unlikely event of a power outage. Restoration was previously referred to as Black Start.
- **Curtailment** – the potential impact of the Window 3 and OHA pilot projects on renewable energy curtailment.

This report provides an explanation of the assessment methodologies that the ESO has used as well as the analysis and results. The analysis and results of this report, along with the work ARUP has undertaken as part of Ofgem's initial project assessments for the third window and OHA pilot will enable Ofgem to assess the potential impact to GB consumers of the various interconnectors and offshore hybrid assets.

2. Introduction

Window 3 and Offshore Hybrid Asset Pilot Projects

In August 2020, Ofgem launched a review of their regulatory policy and approach to new electricity interconnectors. Ofgem's interconnector policy review decision[1], published in December 2021, included an intention to launch a third cap and floor application window for electricity interconnectors, alongside a pilot window for offshore hybrid assets (OHAs, previously referred to as multi-purpose interconnectors). Ofgem opened the third application window for electricity interconnectors on 1st September 2022 and closed it on 10th January 2023. Seven projects are being assessed as part of the Window 3 Initial Project Assessment (IPA). The OHA pilot application period ran from the 1st September 2022 to the 31st October 2022, with two projects being assessed.

Project Name	Asset Type	Capacity (MW)	Connecting country	GB Connection	Assumed Operation date
Aminth	W3	1400	Denmark	Mablethorpe	01/01/2031
AQUIND	W3	2000	France	Lovedean	01/01/2027
Cronos	W3	1400	Belgium	Kemsley	01/10/2029
LirIC	W3	700	Northern Ireland	Kilmarnock South	01/01/2030
MaresConnect	W3	750	Ireland	Bodelwyddan	01/01/2030
NU-Link	W3	1200	Netherlands	Mablethorpe	01/01/2031
Tarchon	W3	1400	Germany	East Anglia	01/01/2030
Lionlink	OHA	1800	Netherlands	Friston	01/01/2030
Nautilus	OHA	1400	Belgium	Grain	01/01/2030

Table 1: Cap and Floor Window 3 projects and Offshore Hybrid Asset pilot scheme projects[2]

ARUP were employed by Ofgem to update the needs case assessment framework for the Window 3 and OHA pilot: they were then employed separately to undertake the CBA. The assessment includes an expanded set of impact categories, including:

- Socio-economic welfare
- Network costs
- System operability
- Constraint costs
- Decarbonisation
- Security of supply
- Hard to monetise impacts.

[1] Interconnector Policy Review - Decision | Ofgem

[2] Although Aminth is physically an OHA, it applied via Window 3, and hence for the purposes of this assessment it is classified as a W3 project.

The analysis that the ESO has undertaken is broken down into the five main assessment areas. These are:

- Constraint costs
- Frequency
- Reactive power
- Restoration
- Curtailment

Frequency, reactive power and restoration (formerly known as Black Start) are all elements of system operability.

This report provides an explanation of the assessment methodologies that the ESO has used as well as the analysis and results. This report, along with the analysis that ARUP has undertaken as part of Ofgem's Cap and Floor Window 3 and OHA pilot scheme assessment will enable Ofgem to assess the potential impact to GB consumers of the various interconnectors and offshore hybrid assets participating in the assessment.

The methodologies used for the ESO's analysis build on the work undertaken in previous Cap and Floor assessments and have been updated to reflect any developments, for example in markets or technologies.

Structure of report

This report is broken down into various sections.

Section 3 provides an overview of the methodology used and the modelling framework.

Sections 4 – 8 cover the five assessment areas covered within the report. These are:

- **Section 4 -** Constraint costs
- **Section 5 -** Frequency
- **Section 6 -** Reactive power
- **Section 7 -** Restoration
- **Section 8 -** Curtailment

Each of these sections provides a description and background on the indicator, the methodology used for the modelling and a summary of the results.

Sections 4 - 8 provide the results for each individual assessment area by W3 project and OHA pilot project.

Section 9 provides the results for each individual project by assessment areas. Hence it is possible to see the relative scale of the impact of the assessment areas for a particular project.

3. Overview of methodology

Introduction

The ESO has provided analysis in three main areas:

- **Constraint costs.** This indicator quantifies the constraint impact of the Window 3 and OHA pilot projects for Great Britain. These are also referred to as balancing market impacts.
- **System Operability.** This assesses the potential savings that an interconnector or OHA may provide to the grid through the provision of ancillary services, for example reductions in costs of procuring frequency response or reactive power services. The services considered are:
  - **Frequency response** – the potential impact of the projects on system frequency.
  - **Reactive power** – the potential impact of the projects on system voltage.
  - **Restoration** – the potential impact of the projects on restoring power to the system in the unlikely event of a power outage. Previously referred to as Black Start.
- **Avoided Renewable Energy Supply (RES) curtailment.** This is an assessment of the level of RES spillage or curtailment that would be avoided due to the addition of an interconnector or OHA.

A detailed description of each of the modelling methods used to obtain results for the above areas is included later in this report. The following section outlines the high-level modelling framework used for the analysis.

Modelling framework

As in previous Cap and Floor Windows, to quantify the widest range of potential impacts a particular interconnector or OHA may have, two project build cases were considered:

- **First Additional (FA).** The project is the only one of the C&F W3 or OHA pilot projects that is operational. Each project is analysed individually, alongside the base of window 1 and 2 projects.
- **Marginal Additional (MA)**. The project is the last, or marginal project to become operational. Each W3 project is analysed assuming all the other W3 interconnectors and OHAs are operational, as well as the window 1 and 2 projects.

It is assumed that by considering both the FA and MA cases they represent a credible outer envelope for the potential benefits or disbenefits that a project may provide. Within the FA – MA envelope there is a very large number of combinations of multiple interconnectors and OHAs that would result in outcomes that fall within the FA – MA range of results, but to consider all the possible permutations would be impractical.

To assess the possible range of impacts that each W3 or OHA pilot project might deliver, three market scenarios were selected. Each scenario represents a different set of market conditions more favourable or detrimental to additional cross-border capacity. The selection of FES used was based on the amount of cross-border interconnection capacity assumed in each scenario.

The three FES22 scenarios selected for the analysis are:

- **Leading the Way (LW):** it includes high levels of cross-border capacity between GB and connected countries and large volumes of renewable generation. **Leading the Way** represents the fastest credible pathway to decarbonisation. It requires significant lifestyle changes and consumers use a mixture of hydrogen and electrification for heating.
- **Consumer Transformation (CT):** it includes relatively lower levels of cross-border capacity and lower volumes of renewable generation. **Consumer Transformation** sees the rise of electrified heating, with consumers willing to change their behaviour. The scenario incorporates high energy efficiency and demand side flexibility.
- **Falling Short (FS):** it includes relatively low levels of cross-border capacity and low volumes of renewable generation. **Falling Short** represents the slowest credible pathway to decarbonisation, with minimal behaviour change. There is decarbonisation in power and transport but not in heat.

The fourth FES22 scenario System Transformation (ST) was not used because Consumer Transformation provided capacity levels closer to the middle point between Leading the Way and Falling Short.

The modelling assumes a 25-year life for each of the interconnector and OHA pilot projects: the operational life of the projects may well be longer. The start date was taken from each project submission and when no specific day or month was given, we have assumed the beginning of the relevant year. We have modelled each individual year: this is particularly important when considering constraint costs as there can be significant variations from year to year as supply, demand and network capability assumptions evolve over time. We are not able to model years beyond our normal twenty-year modelling horizon: for later years we take an average of the last three years.

We have used a single weather year for our modelling with our pan-European market model. 2013 is the standard weather year we use for our constraint cost modelling and represents a good average weather year. 2013 is the year that the ESO currently uses for its long-term network planning work.

Modelling strengths and limitations

The key aim of the assessments is to provide Ofgem with a credible and robust range of the potential impacts to GB consumers of the various interconnector and OHA projects.

The ESO has used its pan-European market model BID3 to undertake the constraint costs forecasting. The model has been used to support its long-term network planning work such as the Network Options Assessment (NOA) and the Transitional Centralised Strategic Network Planning (TCSNP).

Long-term forecasting of potential developments in ancillary services is challenging, due to the high uncertainty regarding long term developments in system operation, especially when considering the minimum 25-year lifespan of an interconnector or OHA. When assumptions have been made regarding how these services may develop, we have stated them.

The ESO has worked closely with ARUP to ensure wherever possible the underlying modelling assumptions used by both parties are aligned.

The strengths and limitations of each individual assessment area are expended on for each indicator.

4. Constraint costs

Introduction

This indicator quantifies the potential impact of the Window 3 and OHA pilot projects on constraints on the network. Constraint costs are also referred to as balancing market impacts.

The electricity network has a finite level of capacity. This means that at periods of high demand and supply there are limitations on how much electricity can flow from one part of the network to another. When the level of electricity is greater than the capability of the network, the ESO must take action to protect the network. These events are known as system constraints. The constraints occur when the system is unable to transmit power due to congestion at one or more parts of the network. At times, to ensure system security, the ESO must either reduce generation or increase demand behind a constraint, and either increase generation or decrease demand in front of the constraint to ensure generation and demand remain in balance. The ESO will need to pay generators not to produce electricity in areas behind constraints and pay other generators to increase in areas free of constraints. Constraint costs are the cost of the actions the ESO takes in the balancing market to ensure generation meets demand and the transmission network can operate safely.

There are several types of constraints but one of the most common on the network are thermal constraints. Thermal constraints refer to an area of the network where the power is congested due to the thermal capability of the equipment. If the system is unable to flow electricity in the way required, the ESO will take actions in the Balancing Market to increase and decrease the amount of electricity at different locations on the network.

There are two situations that can cause a transmission constraint:

- **Import:** The energy demand cannot be met by localised generation and the flow on the circuits into that area is limited by the capacity of the circuits.
- **Export:** The generation in the area is not offset by the localised demand and the flow on the circuits out of the area is limited by the capacity of the circuits.

Methodology

Pan-European market modelling

The ESO undertakes constraint cost forecasting with our pan-European market model BID3. The modelling is performed in two steps:

Dispatch (unconstrained)

The market first schedules generation so that supply meets demand at each point in time, assuming the transmission network is capable of sending power wherever it is needed i.e. unconstrained. We approximate this through our dispatch where we schedule generation to meet demand, whilst minimising cost (which is equivalent to a competitive market where generators charge their marginal cost). This can also be thought of as merit order dispatch. This provides us with a forecast of the market solution at gate closure where there are no transmission network bottlenecks.

Redispatch (constrained)

If the transmission network were unconstrained then the market would be allowed to dispatch as it saw fit. However, constraints on the transmission network mean that generation sometimes must be restricted in some areas of the network to satisfy boundary constraints and increased elsewhere to balance supply and demand. This duty is performed by the ESO at minimum cost, and it is this activity that we seek to approximate through the redispatch. BID3 therefore takes the unconstrained dispatch as a starting point and redispatches generation such that demand is met in all zones on the network, and all boundary constraints are respected. The solver adjusts the positions such that the cost of doing so is minimised. All of the usual constraints present in a dispatch run are also present in the redispatch, such as start-up and no-load times on generators.

Total constraint costs measure the cost of redispatching plant from the market equilibrium to a configuration which respects constraints on power flows within the network. BID3 performs this via a cost minimisation algorithm. Total constraint costs can then be compared to measure the effects of reinforcements and of changing generation or demand configurations. Forming this metric over the whole of the GB network and examining the problem as a whole, is essential since the Main Integrated Transmission System (MITS) is interconnected and relieving constraints in one area of the country may cause problems elsewhere. However, it is important to both ESO and our stakeholders to be able to identify where issues are on the grid, and therefore be able to provide a narrative, and the logic behind the results. To provide this an additional feature has been added to BID3 where constraint costs can be allocated by boundary. Sometimes constraint costs can never truly be attributed to a single boundary, for example where a zone is interconnected with many other zones in a group as opposed to radially. However, an indication of where constraints are occurring can be provided by allocating constraint costs by boundary.

Within BID3 the ESO specifies three boundary capability (MW) values for each time-period modelled and where applicable in both directions as determined by power system study. These are thermal capability, voltage capability and stability capability. This recognises that the capability of a boundary may be limited in different seasons and time periods by different electrical restrictions. Practically BID3 will only accept the minimum of these three numbers as the limiting capability in the optimisation, in a particular direction. For avoidance of doubt the ESO models the defined and reverse capability of a boundary, where it exists as two separate boundaries each with their own minimum in the optimisation function.

The total constraint cost used to solve a transmission congestion issue is associated with the bid and offer components within the balancing mechanism. The 'bid' is a volume of energy at a £/MWh to reduce generation in an area; and the 'offer' is the associated £/MWh to replace the energy in another area of the system.

The model then considers the power flow restrictions on the network and redispatches generation where necessary to relieve instances where power transfer is greater than capability. The costs associated with moving away from the economic dispatch of generation is called the operational constraint costs and is calculated using the bid price and offer price (£/MWh).

The Present Value (PV) of constraint costs attributable to the new interconnector or OHA is calculated by subtracting the system-wide constraint costs without the new interconnector or OHA from the constraint costs with the new interconnector or OHA. The interpretation of a negative number here means that the interconnector or OHA reduces constraints on the network whereas positive numbers represent an increase in constraint costs.

- We modelled each of the nine interconnector and OHA projects for the First Additional and Marginal Additional cases, for each of the three FES22 scenarios used for the analysis.
- For FES22 the last year we are able to model is 2042: for any years after 2042 we used an average of the last three years, i.e. the average of 2040, 2041 and 2042. This is our standard approach for long term constraint cost modelling.
- By undertaking runs with the interconnector or OHA present (the factual), and an identical run except the interconnector or OHA is not present (the counterfactual), we are able to quantify the impact on constraint costs of each interconnector or OHA project.

Limitations of constraint cost modelling

To undertake the constraint cost analysis requires the ESO to have the relevant suite of network reinforcements that form an output of the Transitional Centralised Strategic Network Plan (TCSNP) process. Although the FES23 were released in mid-2023, it was not possible to use them for this analysis as the TCSNP process output would not be available until early 2024. Hence the modelling undertaken by the ESO for this report has used three of the FES22 scenarios: Leading the Way, Consumer Transformation and Falling Short, and the optimal network from HND1 / NOA 2021/22 Refresh[3]. These represent the best available source of data at the time the analysis was undertaken.

The constraint cost results in this section represent a view of future constraint costs based on the FES used and the associated reinforcements that are currently scheduled to be constructed and non-network solutions that will become operational. An increase in constraint costs provide a signal for the need for further network reinforcements, or non-network solutions. Our future planning processes will provide an assessment of when such solutions would deliver economic benefit, whilst considering the impact on community, environmental and operability. The cost of reinforcing the network is expected to be lower than the additional constraint costs shown but estimating the required reinforcement costs to mitigate the additional constraint costs attributable to the W3 and OHA projects is difficult as each reinforcement is unique in terms of cost, network capability and timing.

Results

This section shows the results for the constraint cost modelling.

FA Constraint costs results			
NPV, real 2022, £bn, +ve = additional costs	**LW**	**CT**	**FS**
Aminth	1.68	1.97	0.48
AQUIND	7.22	6.33	2.26
Cronos	6.25	7.07	2.99
LionLink	1.92	1.61	0.31
LirIC	0.22	-0.05	0.20
MaresConnect	0.53	0.66	0.35
Nautilus	4.40	5.20	2.40
NU-Link	1.90	2.08	0.57
Tarchon	1.95	0.52	0.04

Table 2: change in constraint costs due to the addition of each interconnector and OHA for the First Additional case.

The table above shows the change in constraint costs in Present Value[4] (PV) terms for each of the nine projects for the First Additional case, for each of the three FES scenarios. Positive numbers represent an increase in constraint costs and negative numbers represent a constraint saving. The figure below shows the same results but in chart format.

[3] The Holistic Network Design (HND) provides a recommended offshore and onshore design for a 2030 electricity network, that facilitates the Government's ambition for 50GW of offshore wind by 2030. The NOA 2021/22 Refresh is an update to the NOA 2021/22 that was published in January 2022 in accordance with standard condition C27 of the NGESO transmission licence. It integrates the HND's offshore network and confirms the wider onshore network requirements.

[4] Present Value, also known as present discounted value, is the value today (or some other specified date) of a future amount of money. For example, the PV constraint costs shown in this report show the present value of 25 years of constraint costs in 2022 GB pounds.

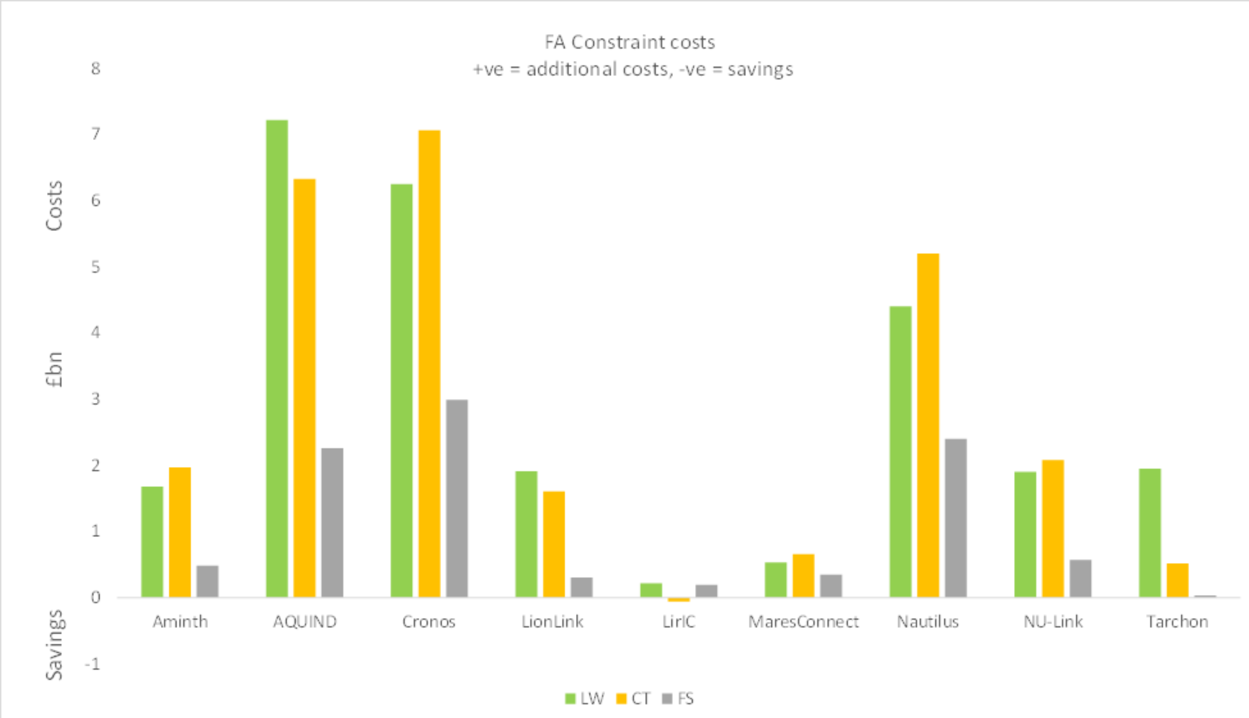

Figure 1: change in constraint costs due to the addition of each interconnector and OHA for the First Additional case, PV, 25 years, real 2022, £bn.

The figure above shows that there is a wide variation in the change in constraint costs. Only one project results in a constraint saving: LirIC for the Consumer Transformation scenario. All the other interconnector and OHA pilot projects result in an increase in constraint costs. There is considerable variation in the increase in constraint costs from one project to another. Differences in constraint costs will be due to a range of factors. Firstly, the location of the interconnector in GB is important, as certain locations will be in more constrained parts of the network. Secondly, the magnitude and direction of flows across the interconnector will have a direct impact on the scale of the constraint actions that need to be taken to achieve a supply demand match that conforms to network capabilities.

Increases in constraint costs are highest in the Leading the Way and Consumer Transformation scenarios. These are driven by the higher levels of renewable generation in these two scenarios resulting in higher price differentials in the two connected markets driving higher flows across the interconnector or OHA and consequently higher constraint management actions.

The highest increase in constraint costs is approximately £7bn. This represents approximately a 17% increase in total constraint costs over the 25-year period compared to total constraint costs when the project is not included.

The flow patterns across interconnectors will vary depending on the connecting country, driven by the market fundamentals in GB and the connected country. Export flows across the W3 interconnectors or OHA pilot projects may lead to increased flows in constrained parts of the GB network, leading to an increase in constraint management actions.

Previous analysis undertaken by the ESO, such as the analysis to support Ofgem's third Cap and Floor Window and OHA pilot regulatory framework[5] has highlighted how the location of an interconnector or OHA and the import and export flows for the project can have a significant impact on whether a project will cause an increase or decrease in total constraint costs. The analysis has shown that only interconnectors connecting to Northern England or Scotland and that

[5] https://www.ofgem.gov.uk/sites/default/files/2022-08/ESOTargetingAnalysis.pdf

are exporting for the majority of the time will reduce overall constraint costs, as they will be helping to reduce north to south flows across GB and hence reduce balancing actions. Any interconnector or OHA that connects in the Midlands or southern England and that is exporting for most of the time is likely to lead to increased constraint costs as more balancing actions will need to be taken to relieve constraints across various boundaries.

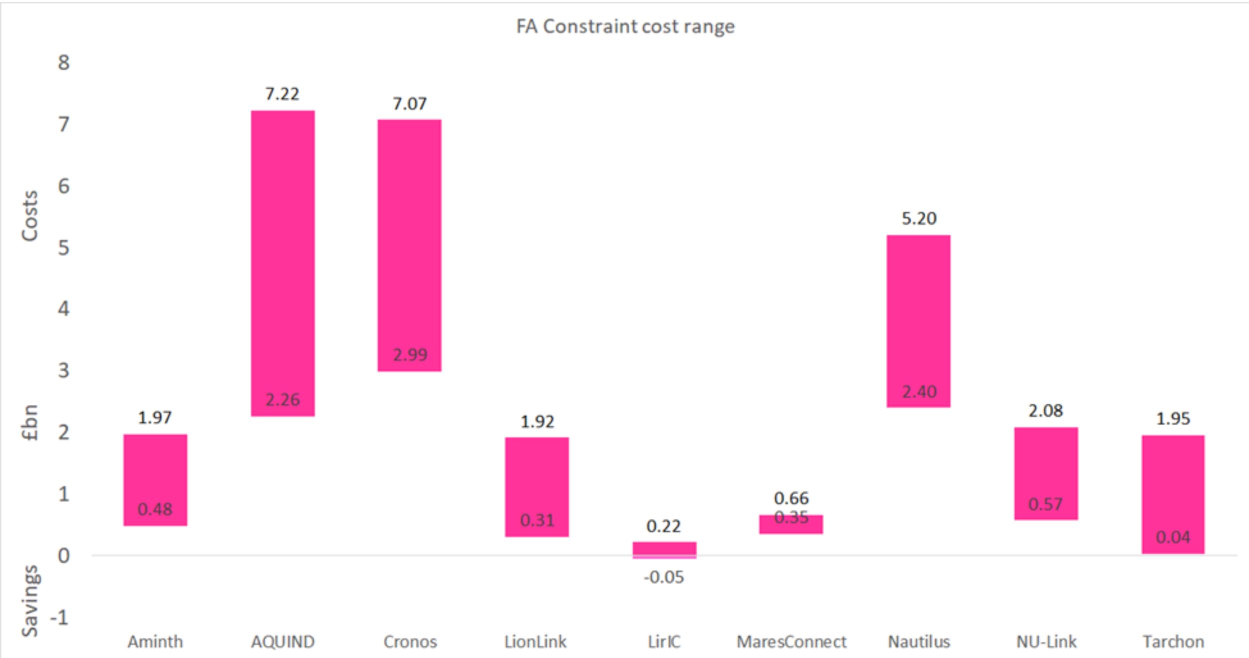

Figure 2: range of change in constraint costs across the three scenarios due to the addition of each interconnector and OHA for the First Additional case, PV, 25-years, real 2022, £bn.

The figure above shows the range across the three scenarios (LW, CT and FS) of change in constraint costs for each interconnector and OHA. The size of the range varies significantly between projects.

MA Constraint costs results

NPV, real 2022, £bn, +ve = additional costs	LW	CT	FS
Aminth	0.50	0.89	0.07
AQUIND	3.54	3.41	0.40
Cronos	3.52	4.59	1.30
LionLink	1.16	1.13	0.04
LirIC	-0.01	-0.23	0.30
MaresConnect	0.27	0.52	0.35
Nautilus	2.80	3.33	1.27
NU-Link	0.79	1.25	0.01
Tarchon	1.30	0.19	-0.18

Table 3: change in constraint costs due to the addition of each interconnector and OHA for the Marginal Additional case.

The table above shows the change in constraint costs in Present Value (PV) terms for each of the nine projects for the Marginal Additional case, for each of the three FES. Positive numbers represent an increase in constraint costs and negative numbers represent a constraint saving. The figure below shows the same results but in chart format.

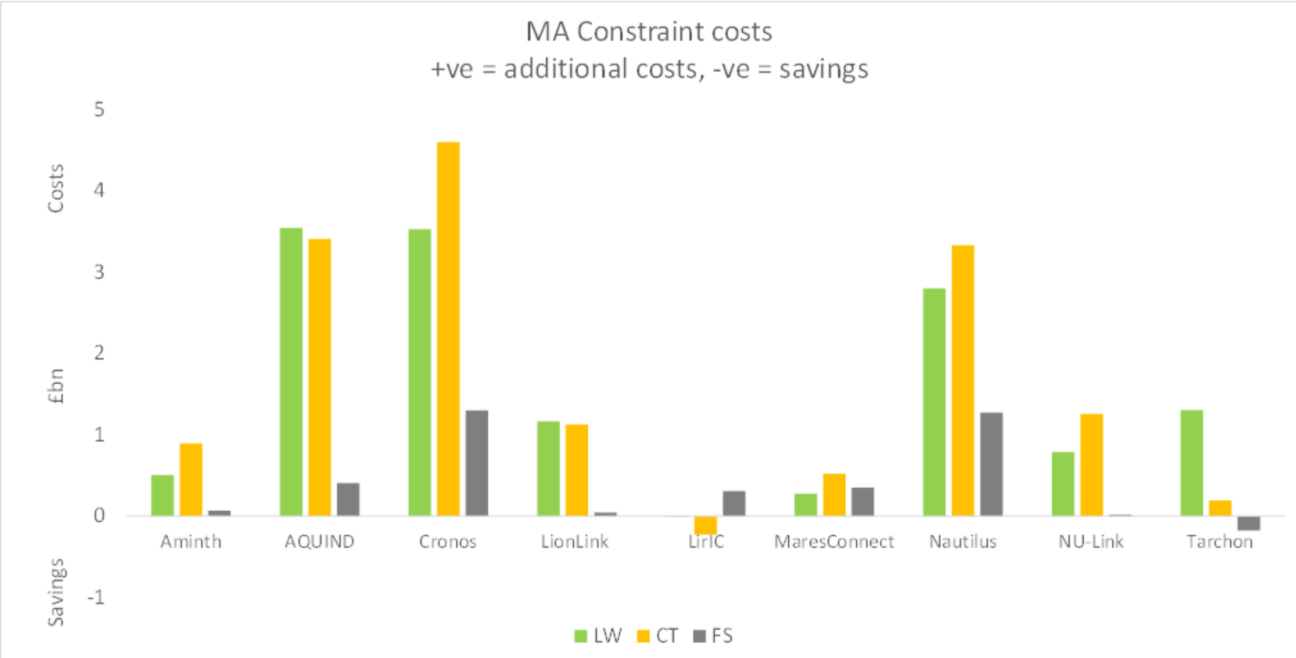

Figure 3: change in constraint costs due to the addition of each interconnector and OHA for the Marginal Additional case, PV, 25-years, real 2022, £bn.

The figure above shows that there is a wide variation in the change in constraint costs. There are only three instances where a project results in constraint savings: LirIC for the Leading the Way and Consumer Transformation scenarios and Tarchon for the Falling Short scenario. All the other interconnector and OHA pilot projects result in an increase in constraint costs. There is considerable variation in the increase in constraint costs from one project to another.

Compared to the First Additional case, in general the Marginal Additional case results in lower increases in constraint costs. This is because the inclusion of all the other Cap and Floor Window 3 and OHA pilot projects within the supply demand mix reduces the impact of any one interconnector or OHA on constraint costs.

The highest increase in constraint costs is approximately £4.5bn. This represents approximately a 7% increase in total constraint costs over the 25-year life of the project.

Care should be taken when interpreting the results of Figure 1 and Figure 3. The charts represent the difference in constraint costs of adding a particular W3 interconnector or OHA project, that is the difference in constraint costs between when the project is included and when the project is excluded. Whilst the levels of additional constraint costs in the Marginal Additional case are lower than in the First Additional case, total constraint costs, that is all the balancing market actions taken in any given year, are higher in the Marginal Additional case. This is because the MA case includes all the W3 interconnectors and OHA projects. The total additional constraint costs for any one scenario shown in Figure 3 (Marginal Additional) effectively represents the total additional constraint costs of including all nine projects. For example, for Leading the Way, the inclusion of all nine W3 interconnector and OHA project results in an increase in constraint costs in PV terms of approximately £14bn over the 25-year period.

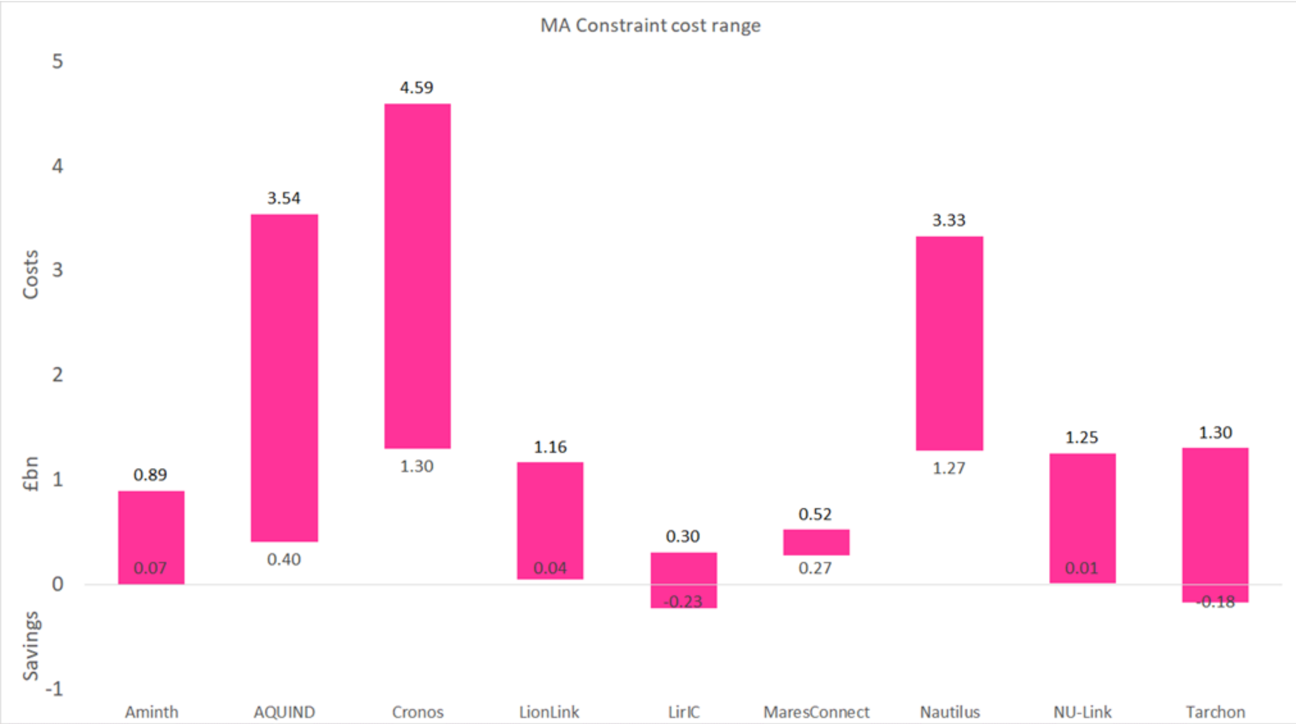

Figure 4: range of change in constraint costs across the three scenarios due to the addition of each interconnector and OHA for the Marginal Additional case, PV, 25-years, real 2022, £bn.

The above figure shows that although the absolute level of additional constraint costs is reduced in the Marginal Additional case, the range, that is the variation across the three scenarios remains high.

5. Frequency response

Introduction

This indicator assesses the potential savings that an interconnector or OHA may provide to the grid through the provision of frequency response services which are necessary to ensure system frequency remains at acceptable levels.

Frequency response is the first of the system operability assessment areas covered in this report. All UK appliances and electrical equipment are designed to work at 50Hz. If the frequency is not 50Hz then appliances and equipment will not work. The tolerance is very small, meaning that the ESO has to keep the frequency within a tight window either side of 50Hz.

Frequency control is achieved through two types of service: response and reserve. Frequency response services are automatically activated using a measurement of frequency to determine an appropriate change in active power. Reserve is dispatched manually by a control room operator following an observed event or in anticipation of a system need. Both response and reserve can deliver a change in active power, provided by a source of either generation or demand. The fundamental aim of our frequency control strategy is to maintain system frequency at the target of 50Hz. While maintaining the frequency, we must also balance the costs and impacts of our actions against the residual level of risk and benefits delivered to the end consumer.

To maintain a stable system frequency of around 50Hz, (set by the Security and Quality of Supply Standard), the ESO procures a range of response services. These services automatically react to changes in system frequency (increases or decreases, triggered by changes in generation or demand), which can happen in both normal operational scenarios and in post-fault situations. As we transition to net zero and a greater proportion of renewable generation capacity, we will have to manage more frequent and faster frequency fluctuations, and we will need to procure services from zero carbon technologies.

In the last decade the average annual system inertia has fallen by around 40%. Lower inertia means that system frequency is less resistant to change, so it will change more quickly when subject to an event, like a sudden loss of generation or demand. The combination of lower inertia and larger losses due to larger loads means that frequency can move quickly.

Each future energy scenario assumes a different level of inertia on the network, with each scenario projecting less inertia than is currently on the system. Inertia levels largely impact the volume of response that is required on the network, with lower inertia systems requiring more and faster frequency response. Stability support to the grid has traditionally been supplied as an inherent by-product of synchronous generators. More asynchronous generation and variable sources of generation create uncertainty in generation and demand forecasts and increased fluctuations in frequency within steady-state limits. Scenarios with more asynchronous and variable sources of generation will likely require more reserve and response.

Currently most asynchronous generation such as renewables, batteries and interconnectors use power electronic convertors which are insensitive to changes in system voltage, frequency and phase: these are known as grid following. Interconnectors and OHAs that are equipped with voltage source convertors (VSC) have the technical potential to provide grid forming services, such as voltage regulation and frequency response.

Methodology

This section describes the methodology for assessing the potential effects on frequency response, both in terms of provisions and requirements. It covers the evaluation of the potential for interconnectors and OHAs to provide frequency response, and the potential value.

The following assumptions are made for the methodology:

- An interconnector or OHA may not be able to reserve capacity to provide a frequency response service because the interconnector or OHA does not decide their operating profile. Unless they withhold capacity from the day-ahead market, they will not be able to guarantee firm capacity. An alternative is to assume that the interconnector can participate in frequency response provision because the frequency response service takes place post-gate closure, i.e. within-day. This would enable interconnectors to provide certainty regarding capacity reservation and availability. Hence flows from the redispatch, or constrained runs are used for the analysis. This simulates the post-gate closure, or within-day supply-demand match taking account of network constraints.

- Agreements are in place with neighbouring TSOs to ensure the impact of providing the service for the GB market is acceptable to the neighbouring TSO. An interconnector delivering frequency response services at one end will see an approximately equal and opposite change in power at the other end. This impacts the neighbouring TSO (and other TSOs in the same synchronous area), their control area and potentially their system frequency and use of response and reserve services. No attempt has been made to attempt to quantify any additional costs that may be incurred by the neighbouring TSO.
- All other technical, regulatory and commercial challenges are overcome.
- There is no repositioning of flows across the interconnector, that is the interconnector continues to import or export or remains at float.
- For each interconnector or OHA, the maximum loading level of frequency response is assumed to be 10% of available capacity. In theory the interconnector or OHA may be able to provide a higher level but this may cause issues with the connected foreign system.

To calculate the potential savings associated with interconnectors providing frequency response, we used the constrained redispatch from the ESO's pan-European market model, BID3, to calculate the potential MWh of frequency response available for each of the interconnectors in turn, for each modelled year, for each of the three scenarios for both the FA and MA cases.

Frequency response requirements were calculated using ESO's in-house tool, which can calculate the total requirement for frequency response based on a range of inputs, including system demand and the largest loss on the system.

To calculate the potential savings, we have used publicly available frequency response costs. Total monthly response costs are published in the Monthly Balancing Services Summary (MBSS) reports[6]. Costs for the new frequency response services of Dynamic Containment (DC), Dynamic Modulation (DM) and Dynamic Regulation (DR) are also available via the ESO Data Portal[7]. We have used data from the MBSS and DC/DM/DR data from the Data Portal to calculate the potential benefit of interconnectors providing frequency response. By assuming that interconnectors provide a frequency response service at a cost equivalent to current DC, DM and DR services, the saving from interconnectors providing the service is equivalent to the difference in average costs observed for frequency response and the average cost observed for DC, DM and DR services.

Limitations of analysis

There are many challenges in quantifying the potential benefits of interconnectors providing frequency response services. The frequency response requirements landscape will change considerably over the next quarter of a century. There will be many revisions and developments as the energy system continues to go through a period of unprecedented change.

The analysis assumes that all technical, regulatory and commercial challenges are overcome, such as the frequency response service taking place post-gate closure, agreeing frequency exchange rules with the connected foreign system and ensuring effective energy transfer settlement. Rather than provide a range of outcomes for each combination of FA/MA and FES, a single result is produced for each project for each scenario and case.

If all the challenges and issues listed above are not overcome, then the level of service that an interconnector or OHA may be able to provide will be lower than that forecast. However, reform of the ESO's ancillary service and balancing markets is crucial to ensuring that we can operate a zero-carbon electricity system by 2025, and fully decarbonise by 2035. These reforms are designed to make markets more efficient, accessible, and liquid, which may potentially lead to even greater levels of participation from interconnectors and OHAs than assumed within this analysis.

[6] https://www.nationalgrideso.com/data-portal/mbss

[7] https://www.nationalgrideso.com/data-portal

Results

The following figures show the savings for frequency response in present value (25-year, 2022 £m) for each of the Cap and Floor Window 3 projects and OHA pilot projects.

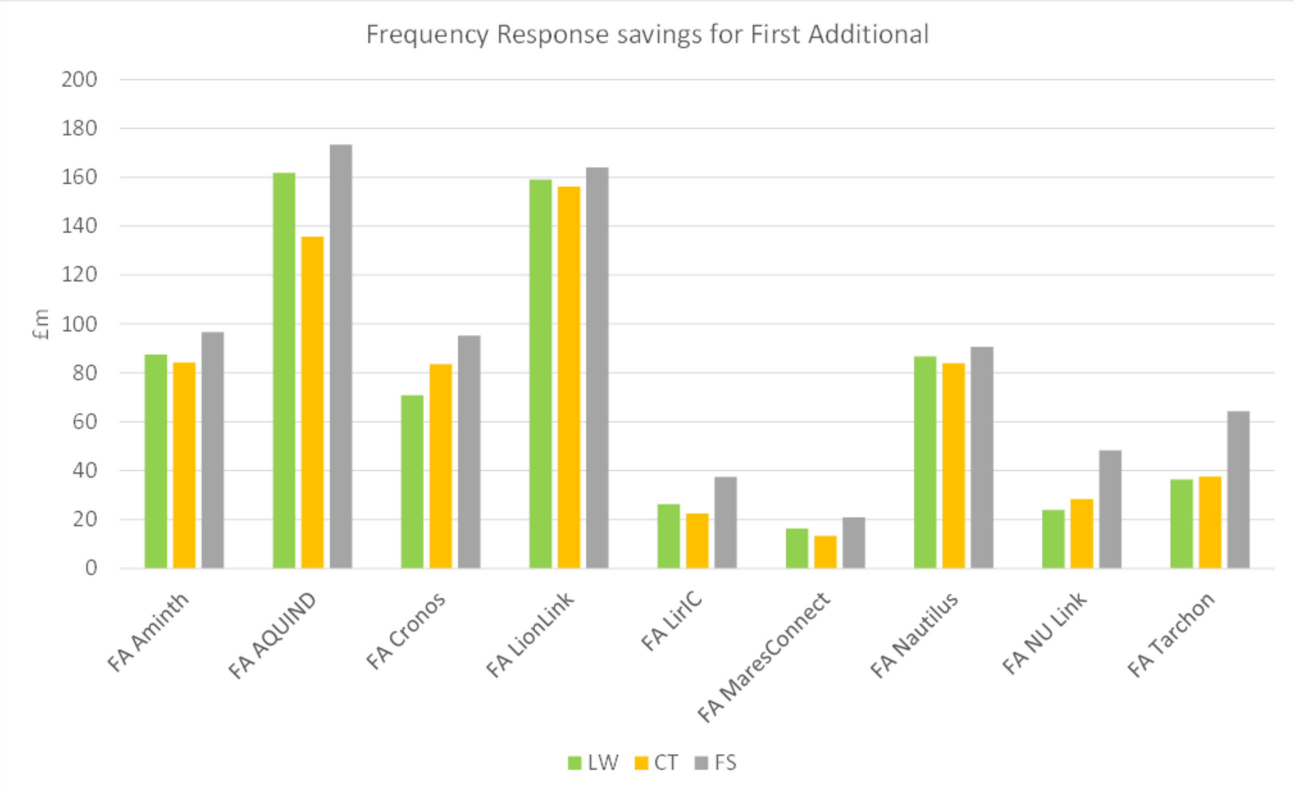

Figure 5: Frequency Response savings for all interconnectors and OHAs for First Additional case, Present Value 25-year, real 2022, £m.

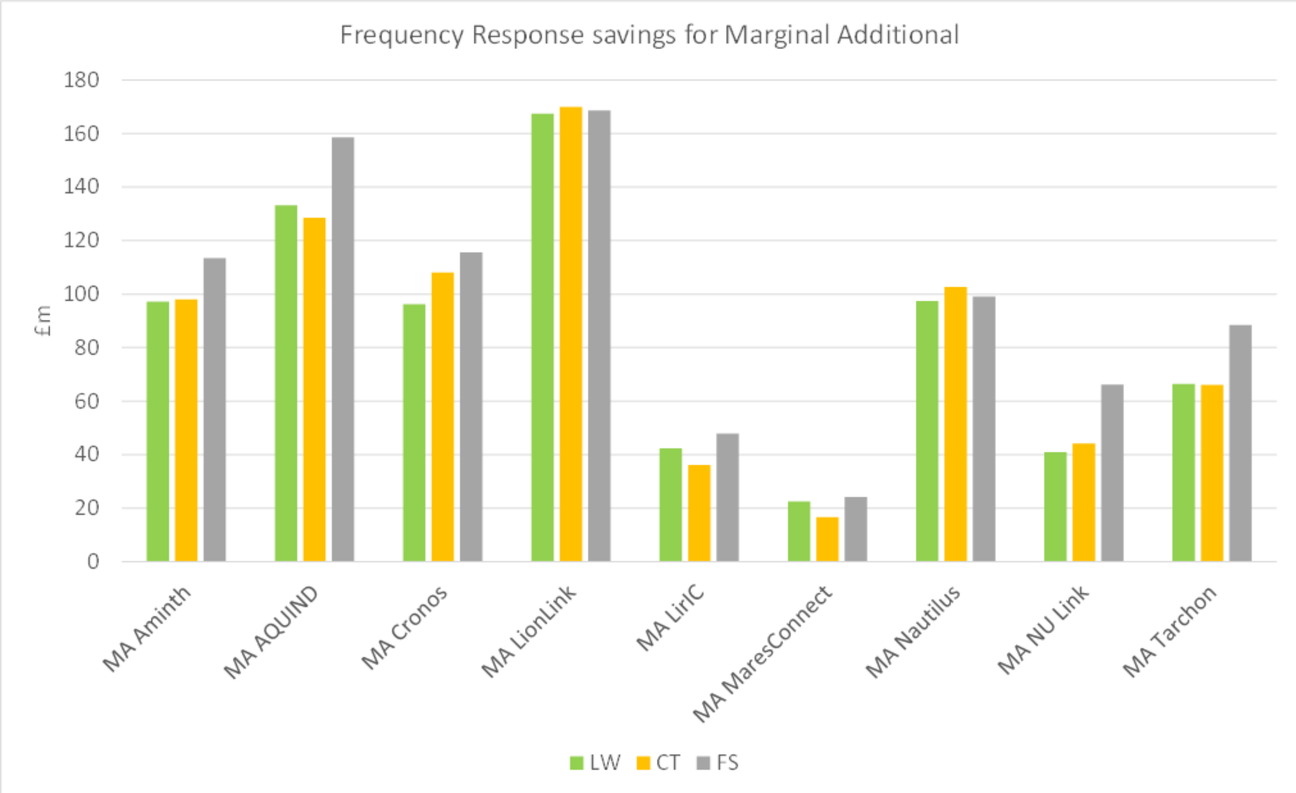

Figure 6: Frequency Response savings for all interconnectors and OHAs for Marginal Additional case, Present Value 25-year, real 2022, £m.

The above figures show the high variation in frequency response savings across projects. This is primarily driven by flow patterns across each project and the resultant availability of capacity for frequency response services.

It is important to note that there is considerable uncertainty around these forecasts. The analysis assumes that the interconnector's potential frequency response provision is provided at costs similar to those experienced in the DC, DR and DM products: this may be overly optimistic if costs do not reach those seen for DC, DR and DM. The interconnector may also decide to not provide frequency response services. Alternatively, it may be possible for interconnectors and OHAs to provide more than 10% of their capacity for frequency response, potentially leading to higher savings.

6. Reactive power support

Introduction

This indicator assesses the potential savings that an interconnector or OHA may provide to the grid through the provision of reactive power services which are necessary to maintain voltage on the transmission system.

Reactive power is the second of the system operability assessment areas covered in this report. Reactive power describes the background energy movement in an alternating current (AC) system arising from the production of electric and magnetic fields. Devices that store energy through a magnetic field produced by a flow of current are said to absorb reactive power; those that store energy through electric fields are said to generate reactive power. Reactive power services are how the ESO makes sure voltage levels on the system remain within a given range. We instruct generators or other asset owners to either absorb reactive power (decreasing voltage) or generate reactive power (increasing voltage).

The flows of reactive power on the system will affect voltage levels. Unlike system frequency, which is consistent across the network, voltages experienced at points across the system form a 'voltage profile', which is uniquely related to the prevailing real and reactive power supply and demand. We must manage voltage levels on a local level to meet the varying needs of the system. The energy transition and decarbonisation of the electricity system continues to affect voltage management across the transmission network. More reactive power capability and utilisation is required as the reactive power requirement continues to increase and available capacity decreases.

VSC (Voltage Source Converter) technology is a type of high-power electronic converter that allows the provision of reactive power. This means that interconnectors and OHAs using this technology can be used to assist with voltage control. This section summarises the reactive power impact analysis considering the seven third window interconnectors and two OHA pilot projects.

Methodology

Our analysis considered interconnectors and OHAs to be connected between 2027 to 2031. To analyse the system operability impact with respect to reactive power response, we have analysed a scenario with system minimum demand (hence summer minimum case) corresponding to high system voltage conditions.

This modelling was undertaken using a detailed power system model of the GB electricity network that uses power system analysis software. This enables load flow analysis including active and reactive power modelling. It is separate to the BID3 model used for constraint costs analysis.

To develop the network model for this analysis, the starting point was the 2030 network. The impact of additional interconnectors or OHAs is analysed by including them within this network model. All projects connecting before or after 2030 are analysed within the single 2030 model because the connection dates are all close to 2030. The key assumptions are:

- The Future Energy Scenarios (FES) 2022 Leading the Way scenario is used. Due to time constraints, it was not possible to create the necessary network model to be able to use either Consumer Transformation or Falling Short.
- Minimum System demand of 16,110 MW and 13,725 MVAr for England and Wales for a 2030 network.
- 90% availability scaling factors applied for fixed reactors, SVCs and STATCOMs.
- All future reactors which are either in tender stage or under-construction have been assumed in the background.
- Voltage control circuits are also used to resolve voltage profiling.

For each spot year model, multiple scenarios have been simulated to capture the interconnectors and OHA pilot project maximum benefit. We have considered the extremes, Full Import (the interconnector or OHA is at maximum import at all times), Full Export (the interconnector or OHA is at maximum export at all times) and Float (i.e. the interconnector or OHA does not import or export at any time, i.e. 0MW) conditions as summarised below for each interconnector and OHA.

Project name	Asset Type	Connecting Country	GB Substation	Scenarios	Import (MW)	Export (MW)
Aminth	W3	Denmark	Mablethorpe 400kV	Base + Aminth	1400	-1400
AQUIND	W3	France	Lovedean 400kV	Base + AQUIND	2000	-2000
Cronos	W3	Belgium	Kemsley 400kV	Base + Cronos	1400	-1400
LirIC	W3	Northern Ireland	Kilmarnock South 400kV	Base + LirIC	700	-700
MaresConnect	W3	Ireland	Bodelwyddan 400kV	Base + MaresConnect	750	-750
NU-Link	W3	Netherlands	Mablethorpe 400kV	Base + NU-Link	1200	-1200
Tarchon	W3	Germany	East Anglia 400kV	Base + Tarchon	1400	-1400
LionLink	OHA	Netherlands	Friston 400kV	Base + LionLlink	1800	-1800
Nautilus	OHA	Belgium	Grain 400kV	Base + Nautilus	1400	-1400

Table 4: Import/export scenarios considered for each interconnector and OHA.

Reactive power support capabilities of the proposed interconnector or OHA are analysed by carrying out pre-fault voltage studies for the network without the proposed W3 interconnector or OHA and then the network with the proposed W3 interconnector or OHA.

- The network is studied with all existing and under-construction/tendered reactive power support devices.
- For full-import and full-export cases, the system is re-balanced with generators which are further away from the local area. We have endeavoured to ensure power flow direction on all interconnectors and OHAs is the same for all countries i.e. all are in importing or exporting.

Each interconnector or OHA is studied independently by keeping other interconnectors disconnected. But, in real time operation, the reactive power will be shared by nearby active interconnectors.

Due to non-availability of actual reactive capability of proposed Voltage Source Converter (VSC) interconnectors, we have assumed a conservative figure of reactive capacity @0.95 power factor based on past project data. Also, as the reactive capacity of VSC based HVDC is independent of active power flow, the maximum reactive power support is kept constant for all three cases (float, full-import and full-export).

As reactive power is a local problem in its nature, the voltage studies focus on the local areas where the interconnectors are to be connected. All substations within a two-substation range of the connection points to be considered are studied.

Limitations of analysis

Reactive Power generation and absorption requirements for voltage control are regional and vary significantly across the electricity system. System requirements are driven by many factors including demand, generation, and system conditions. Interconnectors are located on the periphery of the network and may not be in the optimal location for providing reactive power services. In addition, long term forecasts for reductions in reactive power costs may be over-optimistic, as recent geopolitical events have caused increased volatility in reactive power costs.

Results

Below is a summary of the indicating reactive power benefit for interconnectors and OHAs across the scenarios analysed. The results show an estimate of reactive support benefits assuming Voltage Source Converter (VSC) based technology. It is important to note however, that there is ongoing work to understand the future voltage requirements across Great

Britain and if any reactive power support is procured as a result, the indicated benefits from interconnectors or OHAs might be reduced.

Project Name	Asset Type	Capacity (MW)	UK Connected Node	MVAr_Float	MVAr_Import	MVAr_Export
Aminth	W3	1400	Mablethorpe 400kV	-460	-460	-460
AQUIND	W3	2000	Lovedean 400kV	-660	-540	-360
Cronos	W3	1400	Kemsley 400kV	-460	-460	-460
LirIC	W3	700	Kilmarnock South 400kV	-230	-230	-230
MaresConnect	W3	750	Bodelwyddan 400kV	-250	-250	-250
NU-Link	W3	1200	Mablethorpe 400kV	-400	-400	-400
Tarchon	W3	1400	East Anglia 400kV	-460	-460	-450
LionLink	OHA	1800	Friston 400kV	-590	-590	-590
Nautilus	OHA	1400	Grain 400kV	-460	-460	-460

Table 5: Reactive power benefit for each interconnector and OHA.

To calculate the potential savings associated with interconnectors and OHAs providing reactive power, we used the constrained redispatch flows from the ESO's pan-European market model BID3 to calculate the potential MVAr available for each of the interconnectors in turn, for each modelled year, for each of the three scenarios[8] for both the First Additional and Marginal Additional cases. Historic reactive power volumes and expenditures are available via the ESO's Monthly Balancing Services Summary reports[9] which provide a historic cost per MVArh. As the reactive power market evolves over the coming decades, we have assumed a percentage reduction in voltage costs[10] which is applied to the theoretical MVAr provided by each interconnector and OHA.

The following figures represent the potential savings if all the potential reactive power benefit that could be provided by each interconnector is actually required: this may not be the case. Hence the values for potential reactive power savings represent an upper estimate.

[8] The reactive power benefits from Table 5 were applied to Leading the Way, Consumer Transformation and Falling Short.

[9] https://www.nationalgrideso.com/data-portal/mbss

[10] Based on economic modelling undertaken for the ESO.

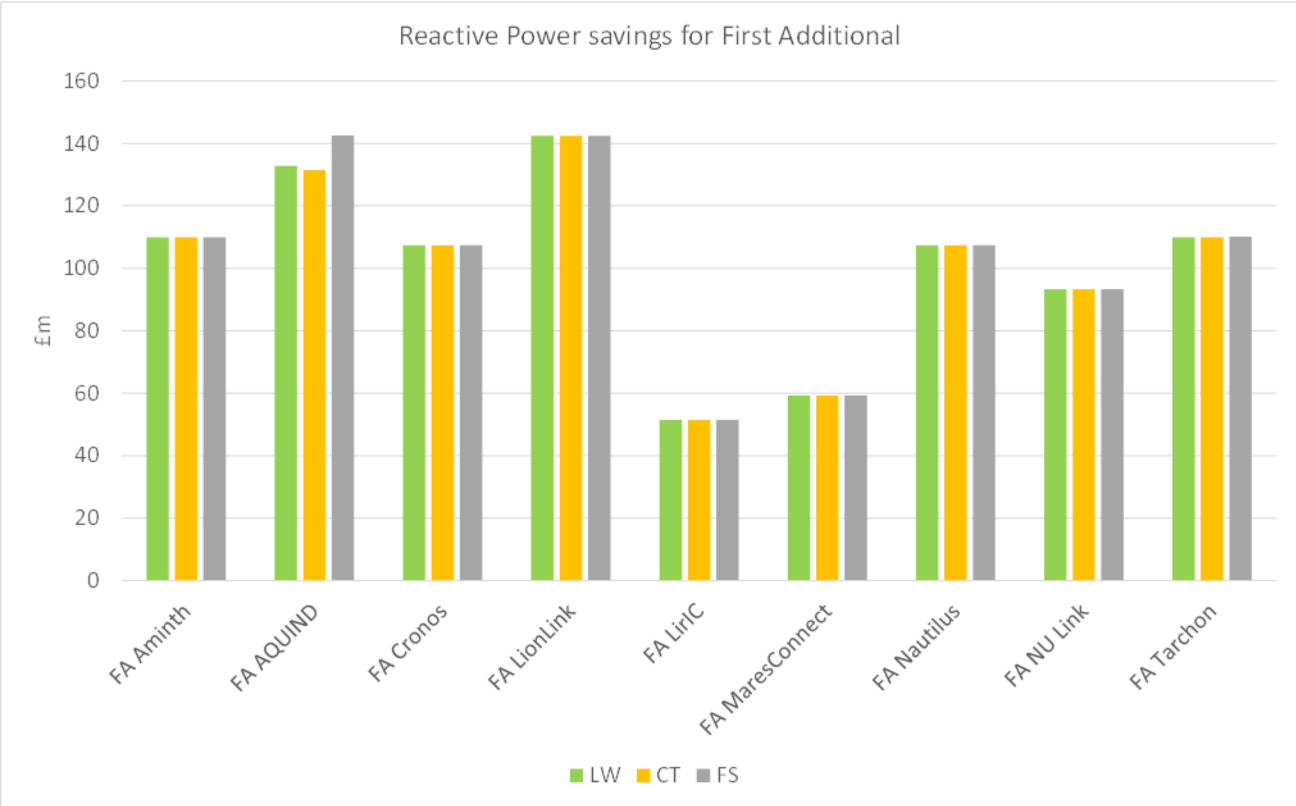

Figure 7: Reactive power savings for all interconnectors and OHAs for First Additional case, Present Value 25-year, real 2022, £m.

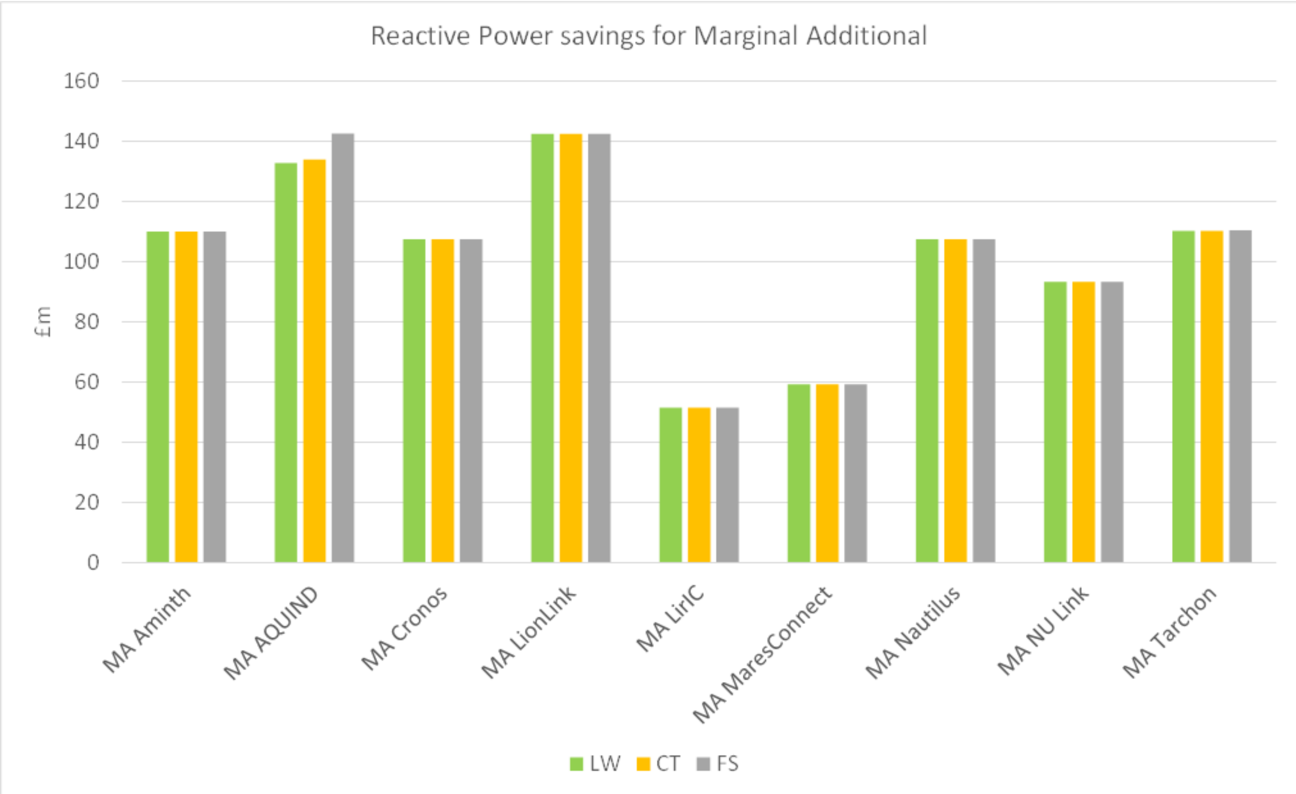

Figure 8: Reactive power savings for all interconnectors and OHAs for Marginal Additional case, Present Value 25-year, real 2022, £m.

The above figures show the potential reactive power savings for both the First Additional and Marginal Additional cases. The figures show that there is little or no variation between the FA and MA cases, and between scenarios. This is because **Table 5: Reactive power benefit for each interconnector and OHA** shows there is little variation in reactive power benefit from each interconnector whether it is importing, exporting or at float.

7. Restoration

Introduction

This indicator assesses the potential savings that an interconnector or OHA may provide to the grid through the provision of restoration services which are necessary to ensure the ESO can restore the system in the event of a partial or total shutdown.

Restoration (formerly known as Black Start) is the third of the system operability assessment areas covered in this report. The restoration service can be procured from a range of Power Generating Modules (PGM) or HVDC systems that have the capability to re-start from shutdown without reliance on external supplies.

The current restoration approach is to use contracted large power stations and interconnectors to energise sections of the transmission system using local demand to establish stable power islands in line with pre-agreed Local Joint Restoration Plans (LJRPs). Subsequently, other generators will join the growing system, and the synchronization of power islands progressively takes place to re-energise the whole network and restore demand across the country until full restoration is completed. For this strategy to work generation must meet demand in local areas whilst maintaining voltage and frequency requirements: the inherent capability of voltage source capability (VSC) interconnectors make them suitable to providing restoration services.

The Electricity System Restoration Standard (ESRS) prescribes new restoration targets effective 31st December 2026, for the ESO to have sufficient capability in place, in an event of a total system shutdown, to restore:

- 60% of transmission electricity demand being restored within 24 hours in all regions, and
- 100% of electricity demand being restored within 5 days nationally.

To be ESRS-compliant by December 2026, the ESO is adopting a restoration approach that implements both traditional and non-traditional restoration service providers. The ESO is proposing a holistic restoration approach that considers both top-down and bottom-up approach to restoration. This approach removes barriers to entry for markets and allows distributed energy resources (DERs) to participate in restoration.

Our vision is that by the middle of the decade we will be running a fully competitive restoration procurement process wherever advantageous, with submissions from a wide range of technologies connected at different voltage levels on the network, with Transmission Owners (TO) and Distribution Network Operators (DNO).

The ESO’s principles for procuring restoration services are:

• A clear and transparent requirement.

• Enabling competition, where appropriate.

• Reducing and removing barriers to entry to enable broader participation.

Methodology

The current contracting strategy for restoration services is to have seven zones, with an average of 3 plants per zone. For this strategy generation must meet demand in local areas whilst maintaining voltage and frequency requirement: this is where the inherent capability of VSC interconnectors provide a great opportunity. For this analysis no limit is placed on the number of interconnectors that can be contracted within each zone.

The analysis assumes the following:

- Zero additional capital costs for restoration services from VSC interconnectors or OHAs.
- Zonal contracting strategy remains in place over the life of the interconnector or OHA.
- Capital costs remain the same for new technologies.

The current plant providing restoration services in each zone were cross-referenced against the three FES22 scenarios to determine which plant would still be available to provide Black Start services across the forecast period.

Existing contractor costs have been used to calculate future contracting cost components, covering availability, testing, feasibility and capital for a range of service providers, including existing providers including interconnectors and new entrants. The average cost of existing, interconnector and new entrants providing a restoration service has been calculated.

Potential savings can then be calculated, with higher savings where there are forecast to be more new market participants in a particular zone driving increased competition.

Limitations of analysis

There will be fundamental changes to the restoration services landscape in the coming decades as the system transforms and becomes more reliant on intermittent energy sources. There is a long-term objective of diversifying technologies and reducing restoration costs. New entrants will participate in restoration services, both at the transmission and distribution network level. Forecasting future cost assumptions over such a long-time horizon is difficult, especially with emerging technologies. The levels of participation of interconnectors and OHAs in providing restoration services may be higher or lower than those assumed leading to relatively higher or lower savings.

Results

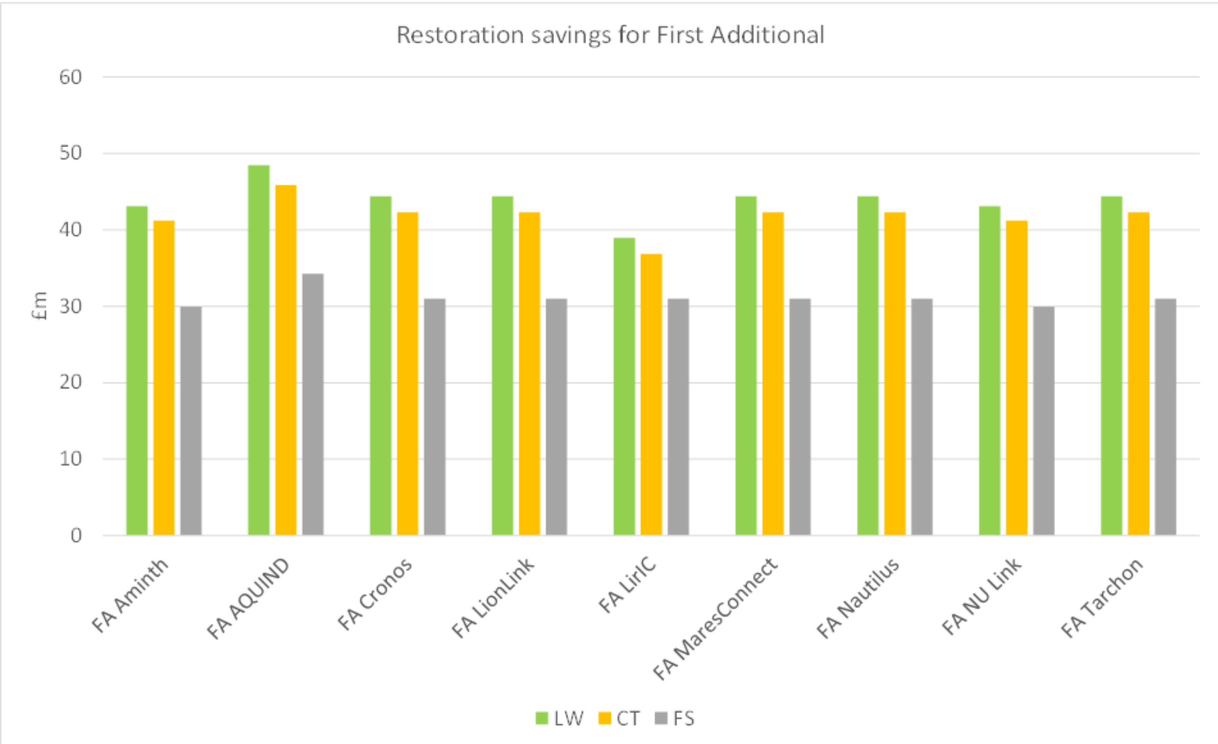

Figure 9: Potential savings for restoration services provided by each interconnector for First Additional case for each of the scenarios, PV, 25-years, real 2022, £m.

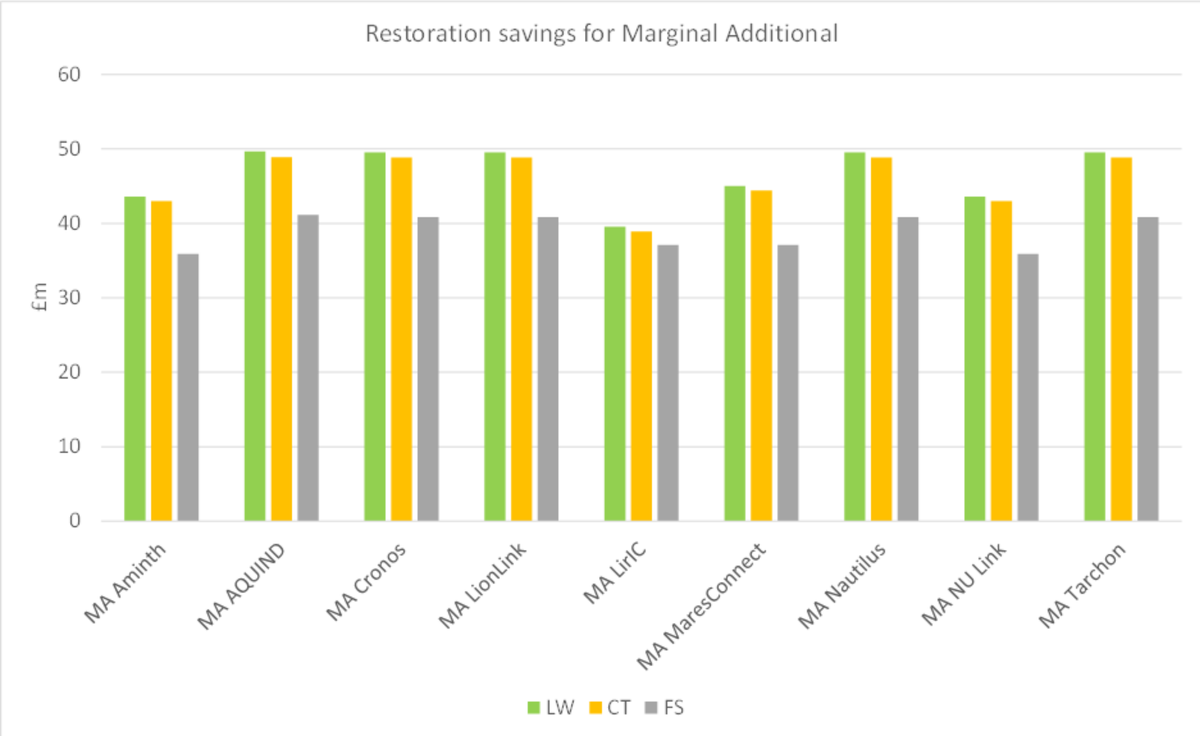

Figure 10: Potential savings for restoration services provided by each interconnector for Marginal Additional case for each of the scenarios, PV, 25-years, real 2022, £m.

The variations in restoration services are primarily driven by a combination of the geographic location of the interconnector or OHA, and the other relevant restoration providers in that zone, and the FES scenario, which forecasts the likely development of generation assets within that zone. Restoration savings are higher in the Marginal Additional case, as lower interconnector base costs were assumed driven by increased competition.

As stated previously, there is considerable uncertainty regarding forecasting savings in restoration services, as over the next decade and beyond, the GB generation technology mix, and the make-up of participants in the restoration market will change fundamentally. New market participants may drive competition further such that interconnector and OHA costs are even lower, providing even greater savings, or alternatively new entrants market activity may result in reduced participation from interconnectors or OHAs.

8. Avoided RES curtailment

Introduction

This indicator assesses the potential volumes of renewable energy supply (RES) curtailment that can be avoided when an interconnector or OHA is connected to the grid.

Curtailment is when the output from a generation unit connected to the electricity system is reduced due to operational balancing. To avoid curtailment, flexible solutions such as interconnectors, energy storage, Demand Side Response (DSR) or electrolysis could be used to maximise the use of renewable energy supplies (RES).

Methodology

RES curtailment is a standard output from our pan-European market model BID3. For this analysis we have used outputs from the constrained, redispatch to provide a forecast of the levels of RES curtailment that can be avoided when each of the Window 3 interconnector and OHA pilot projects are included.

Results

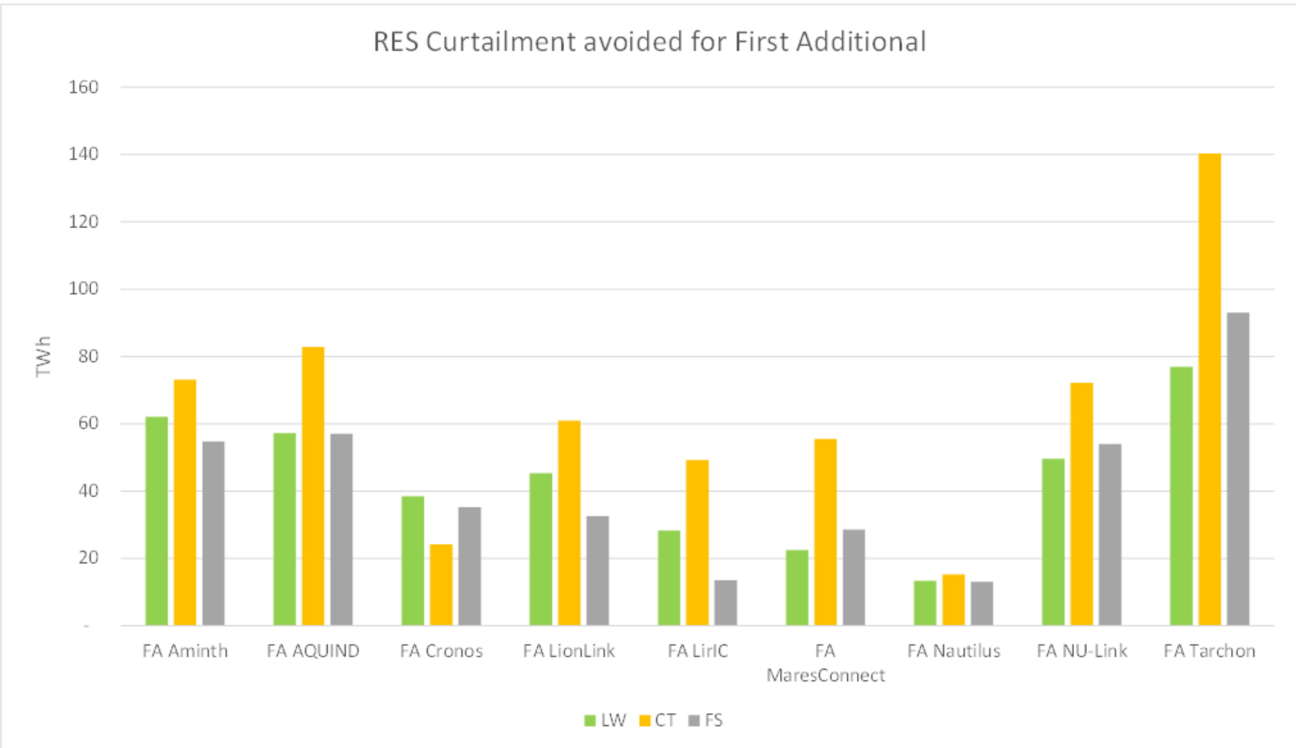

Figure 11: RES curtailment avoided in the First Additional case. 25-year total.

The above figure shows RES curtailment avoided for each W3 interconnector and OHA pilot project for each scenario for the 25-year life of the project, for the First Additional case. The figure shows that all the projects provide reductions in RES curtailment for all scenarios in the First Additional case. The highest levels of RES curtailment avoided are seen in the Consumer Transformation scenario, but there are significant volumes of RES curtailment avoided in both Leading the Way and Falling Short. Consumer Transformation has high levels of renewable generation combined with low hydrogen production from electrolysis which leads to the highest levels of RES curtailment across the three scenarios. Hence the addition of an extra interconnector or OHA in Consumer Transformation provides an opportunity for increased levels of avoided RES curtailment. Leading the Way also has high levels of renewable generation but has higher levels of hydrogen production from electrolysis than in Consumer Transformation hence the lower levels of RES curtailment avoided compared to Consumer Transformation. Falling Short has relatively lower levels of renewable generation but also has minimal levels of electrolysis leading to high levels of RES curtailment, hence high levels of RES curtailment avoided when an additional interconnector or OHA is added.

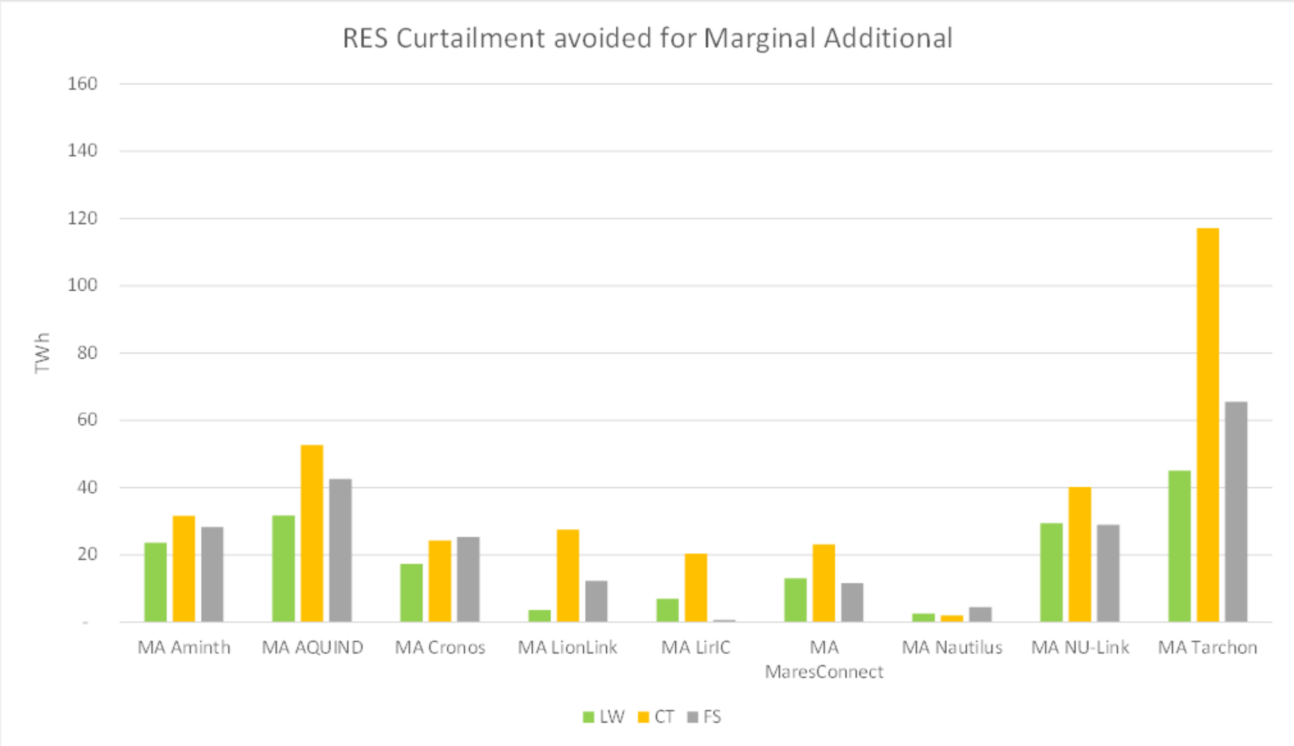

Figure 12: RES curtailment avoided in the First Additional case. 25-year total.

The above figure shows RES curtailment avoided for each W3 interconnector and OHA pilot project for each scenario for the 25-year life of the project, for the Marginal Additional case. The figure shows that all the projects provide reductions in RES curtailment for all scenarios in the Marginal Additional case, although the scale of the RES curtailment avoided are lower than in the First Additional case.

The highest levels of RES curtailment avoided are seen in the Consumer Transformation scenario, but for most of the projects there are significant volumes of RES curtailment avoided in both Leading the Way and Falling Short.

Tarchon results in the highest levels of RES curtailment avoided in both the First Additional and Marginal Additional cases. An examination of the annual RES curtailment figures for Tarchon shows that the final three years modelled in BID3 (2040 to 2042), which are used to extrapolate the later years, are particularly high.

9. Results by project

Introduction

The following chapters shows the results for each individual W3 interconnector and OHA.

10. Aminth

Although Aminth is physically an OHA, it applied via Window 3, and hence for the purposes of this assessment it is classified as a W3 project. It has a capacity of 1.4GW and connects to Denmark.

PV constraint costs

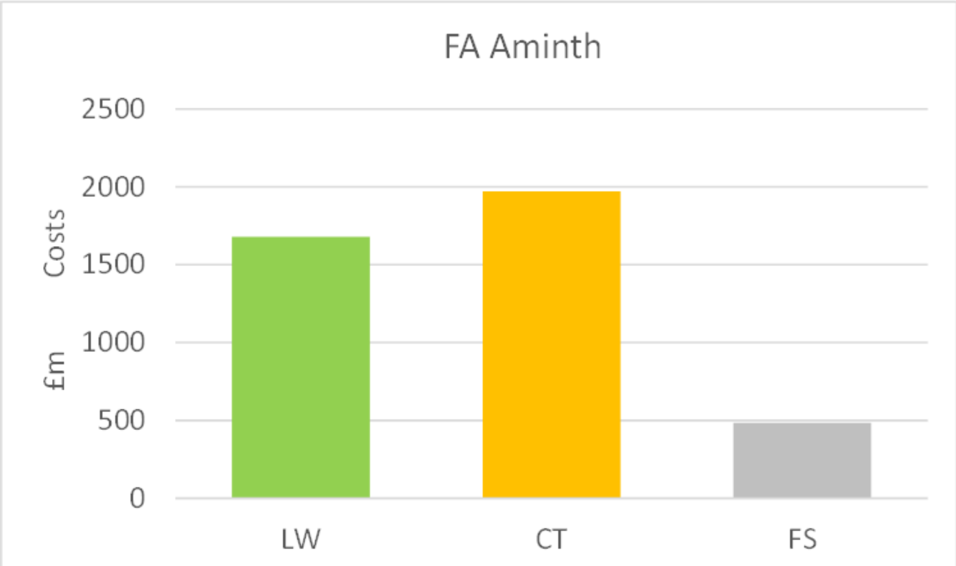

Figure 13: PV additional constraint costs due to Aminth for the First Additional case, Present Value 25-year, real 2022, £m.

The above figure shows the additional constraint costs with the inclusion of Aminth for the FA case. In the Leading the Way scenario (LW) constraint costs are increased by £1.7bn, in Consumer Transformation (CT) by £2bn and in the Falling Short (FS) scenario by £0.5bn.

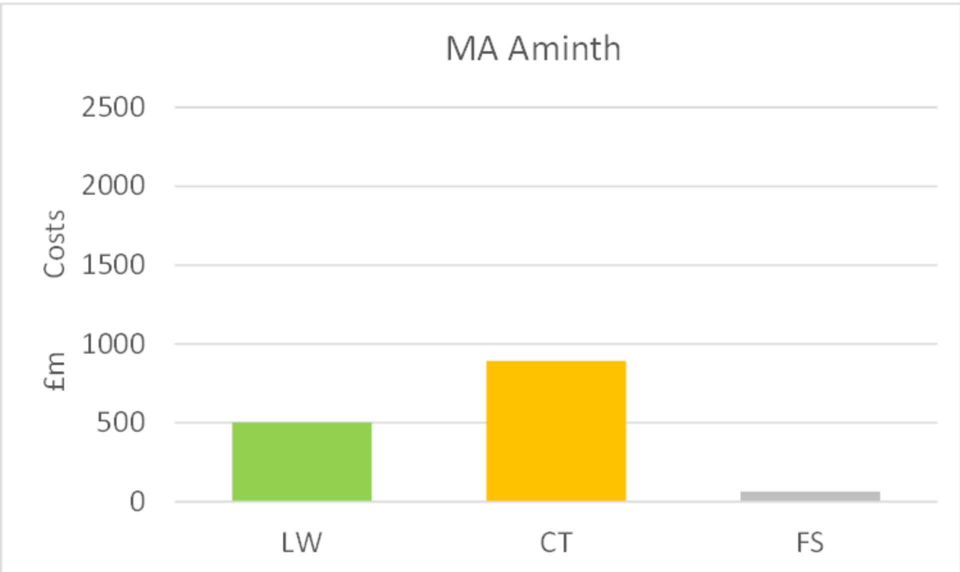

Figure 14: PV additional constraint costs due to Aminth for the Marginal Additional case, Present Value 25-year, real 2022, £m.

The above figure shows the additional constraint costs with the inclusion of Aminth for the MA case. Additional constraint costs are significantly lower than in the FA case. This is because the inclusion of the other OHA and Window 3 projects within the supply demand mix reduces the impact any one interconnector has on constraint costs.

Annual constraint costs

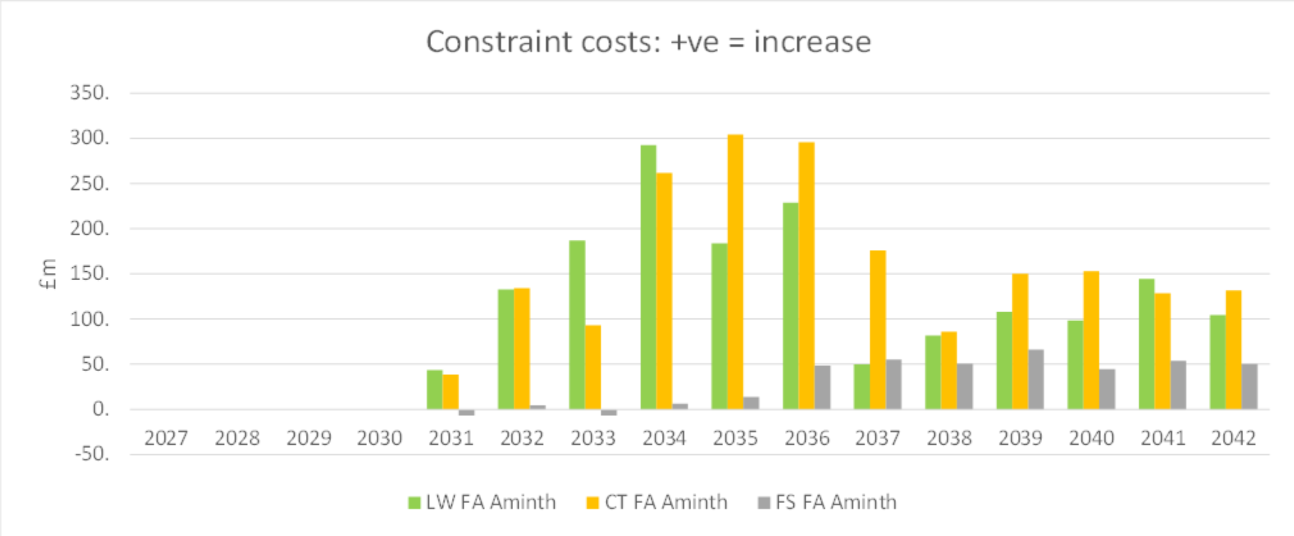

Figure 15: Additional annual constraint costs due to Aminth for the First Additional case.

The above figure shows that Aminth results in an increase in constraint costs of approximately £200m to £300m (undiscounted) in CT and LW for the years 2034 to 2036. In FS constraint cost increases are much lower, with small savings in some years.

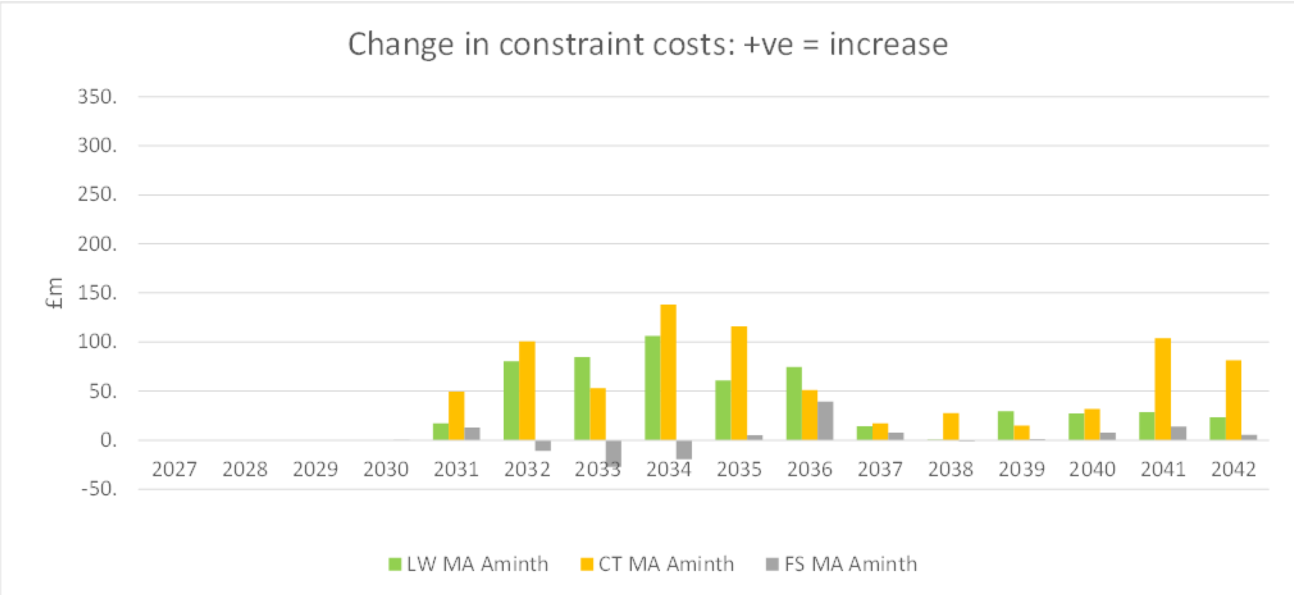

Figure 16: Additional annual constraint costs due to Aminth for the Marginal Additional case.

In the Marginal Additional case, Aminth results in an increase in constraint costs of approximately £50m to £100m (undiscounted) in CT and LW for the years 2032 to 2035. FS shows constraint savings for the years 2032 to 2034, and for the other years shows much lower levels of additional constraint costs compared to LW and CT.

Annual import and export flows for dispatch and redispatch

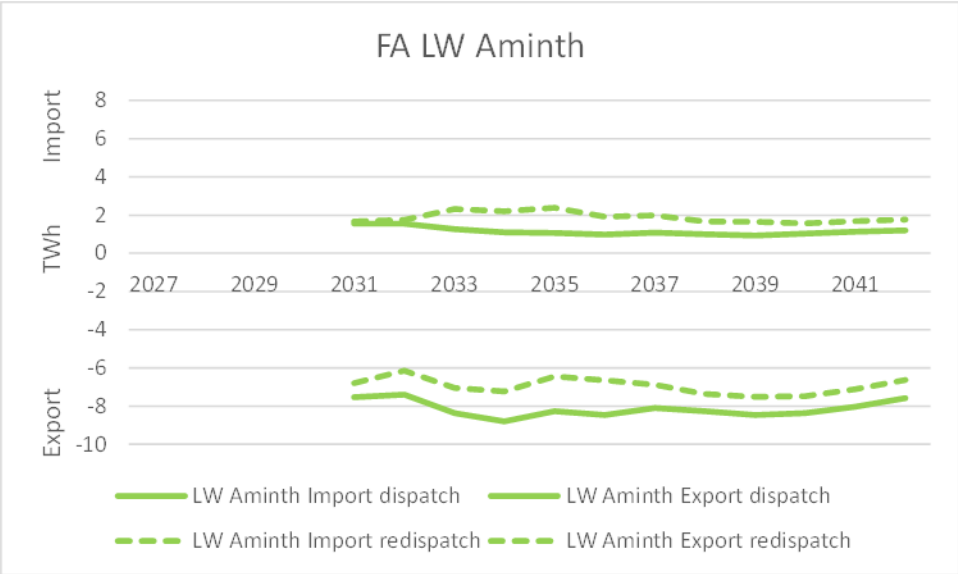

Figure 17: Annual import and export flows for Aminth in the FA case for Leading the Way.

The above figure shows high exports and low imports in the dispatch. The redispatch shows a reduction in exports and an increase in imports.

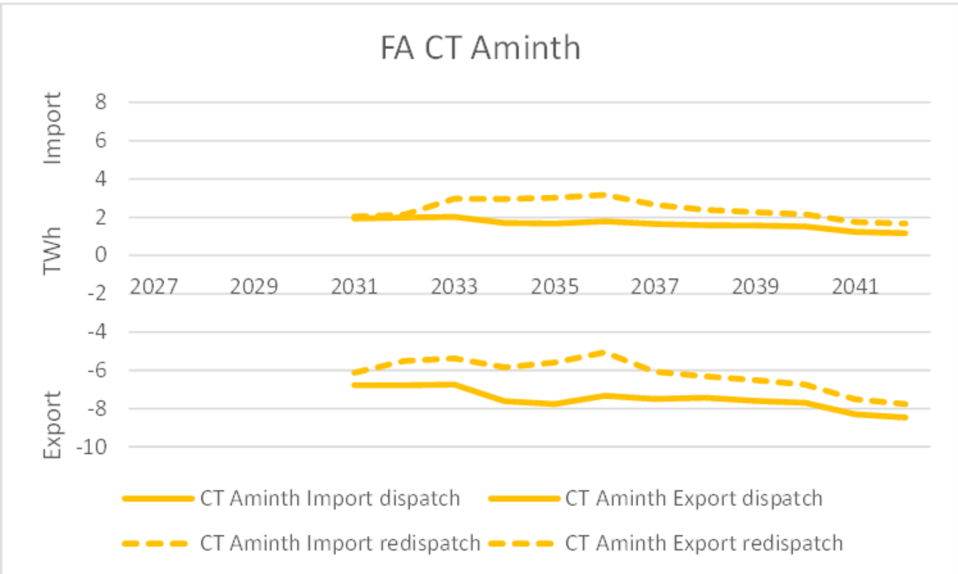

Figure 18: Annual import and export flows for Aminth in the FA case for Consumer Transformation.

The above figure shows high exports and low imports in the dispatch. The redispatch shows a reduction in exports and an increase in imports.

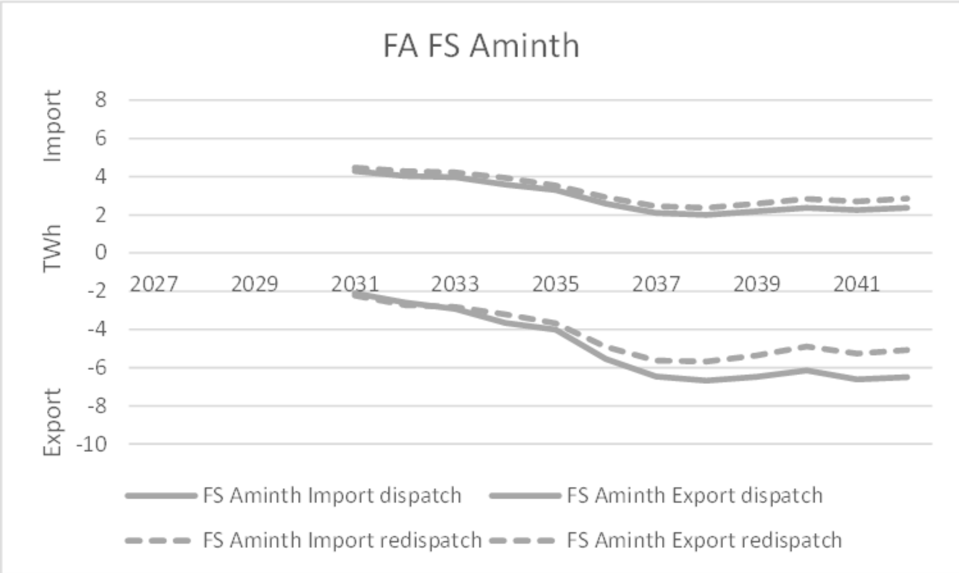

Figure 19: Annual import and export flows for Aminth in the FA case for Falling Short.

The above figure shows that for the First Additional case Aminth has increasing levels of exports over the forecast period up to 2038 and decreasing levels of imports out to 2037 in the dispatch for Falling Short. The redispatch shows a reduction in exports after 2033 and a slight increase in imports.

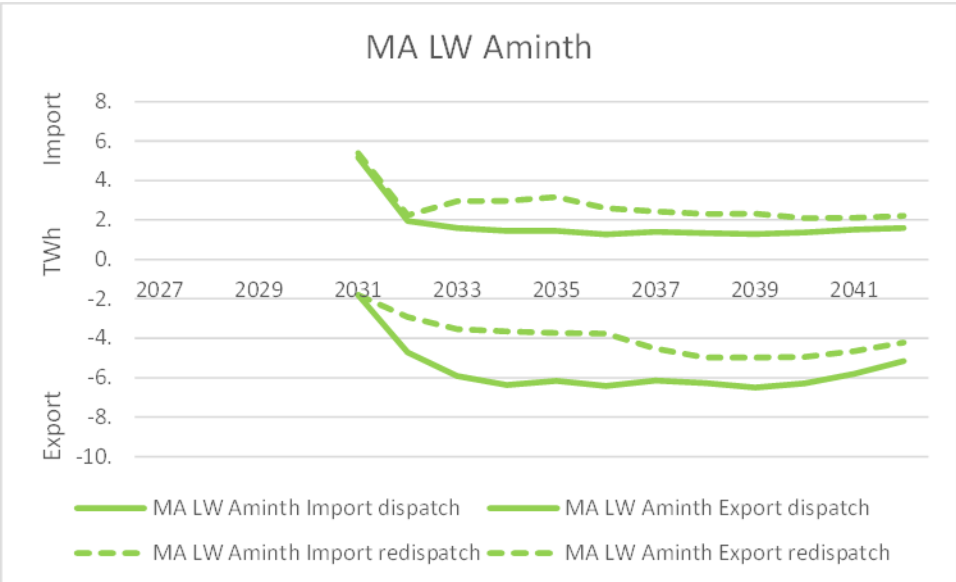

Figure 20: Annual import and export flows for Aminth in the MA case for Leading the Way.

The above figure shows high exports, but lower than in the FA case, and low imports in the dispatch. The redispatch shows a significant reduction in exports and an increase in imports.

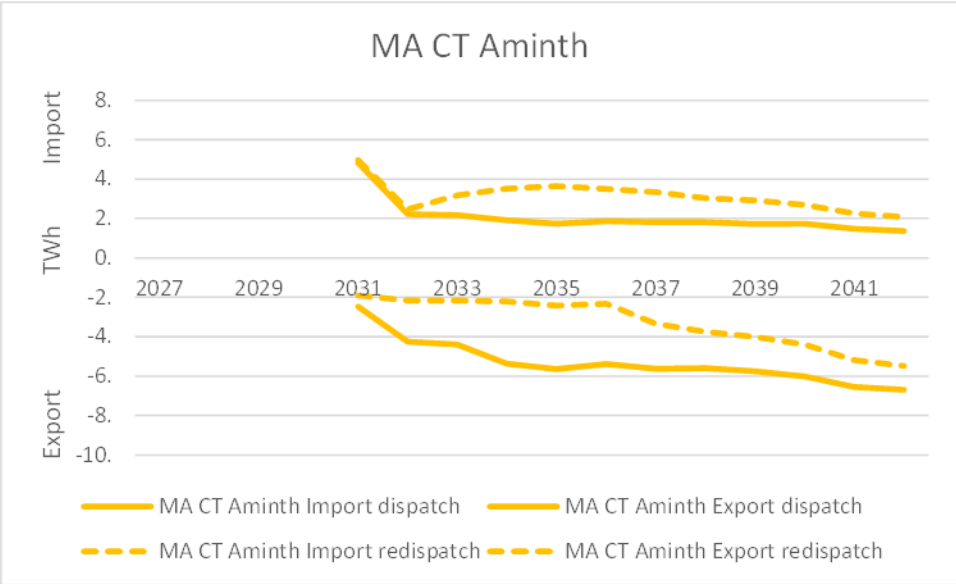

Figure 21: Annual import and export flows for Aminth in the MA case for Consumer Transformation.

The above figure shows high exports, but lower than in the FA case, and low imports in the dispatch. The redispatch shows exports reduced to nearly zero in the early to mid-2030s and an increase in imports.

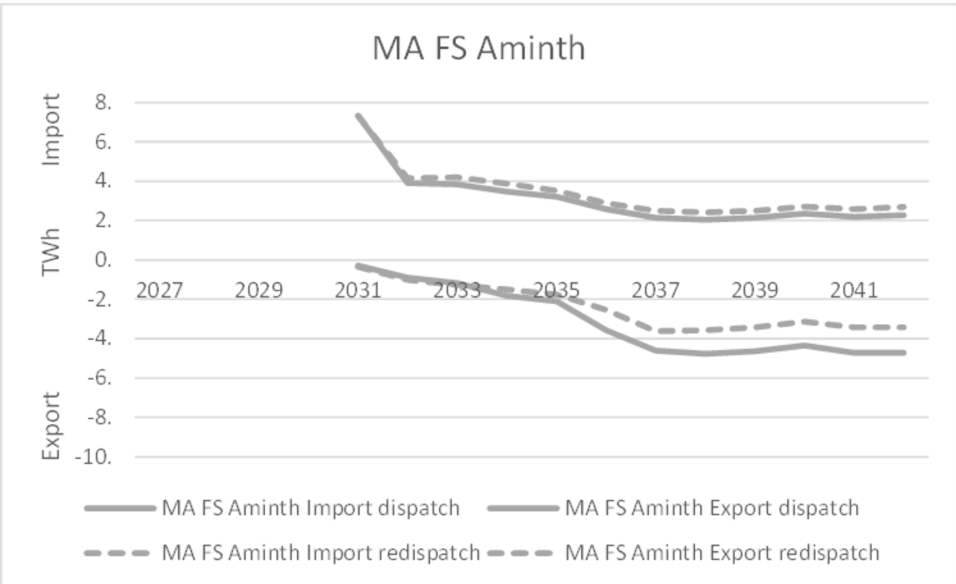

Figure 22: Annual import and export flows for Aminth in the MA case for Falling Short.

The above figure shows that for the Marginal Additional case, Aminth has increasing exports, but lower than in the First Additional case, and decreasing imports in the dispatch, higher in 2031 than in the FA case, but similar to those in FA for all subsequent years. The redispatch shows some reduction in exports, especially in the later years and a small increase in imports.

Change in constraint costs by boundary

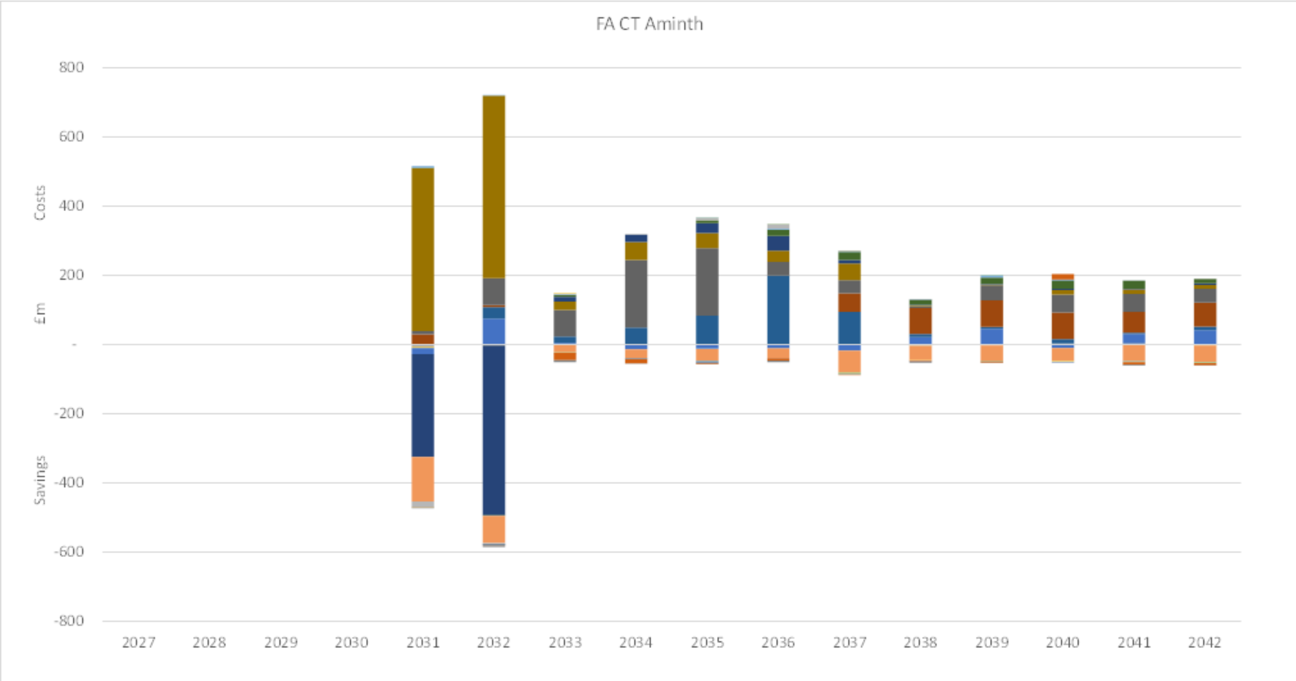

Figure 23: Change in constraint costs by boundary for Aminth for the First Additional case for Consumer Transformation.

The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for Aminth for the First Additional case for the Consumer Transformation scenario. Each different colour represents the change in constraint costs for a particular boundary. It is important to note that the chart shows changes in constraint costs by boundary, i.e. the difference between constraint costs when the project is included and when the project is excluded.

The figure shows that Aminth increases constraint costs on certain boundaries but also reduces constraint costs on others. Whether the impact is an increase in constraint costs or a reduction in constraint costs for a particular boundary, changes from year to year. The size of change in constraint costs by boundary can also vary significantly from year to year. This is shown clearly in the years 2031 to 2033. The figure also shows that the specific boundaries that have the greatest impact on the total change in constraint costs can vary from year to year. These factors are a result of the changes in demand, supply and network capability over time.

In general, Aminth increases constraint costs on several northern boundaries, but relieves congestion on certain midland boundaries in the early years. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

ESO

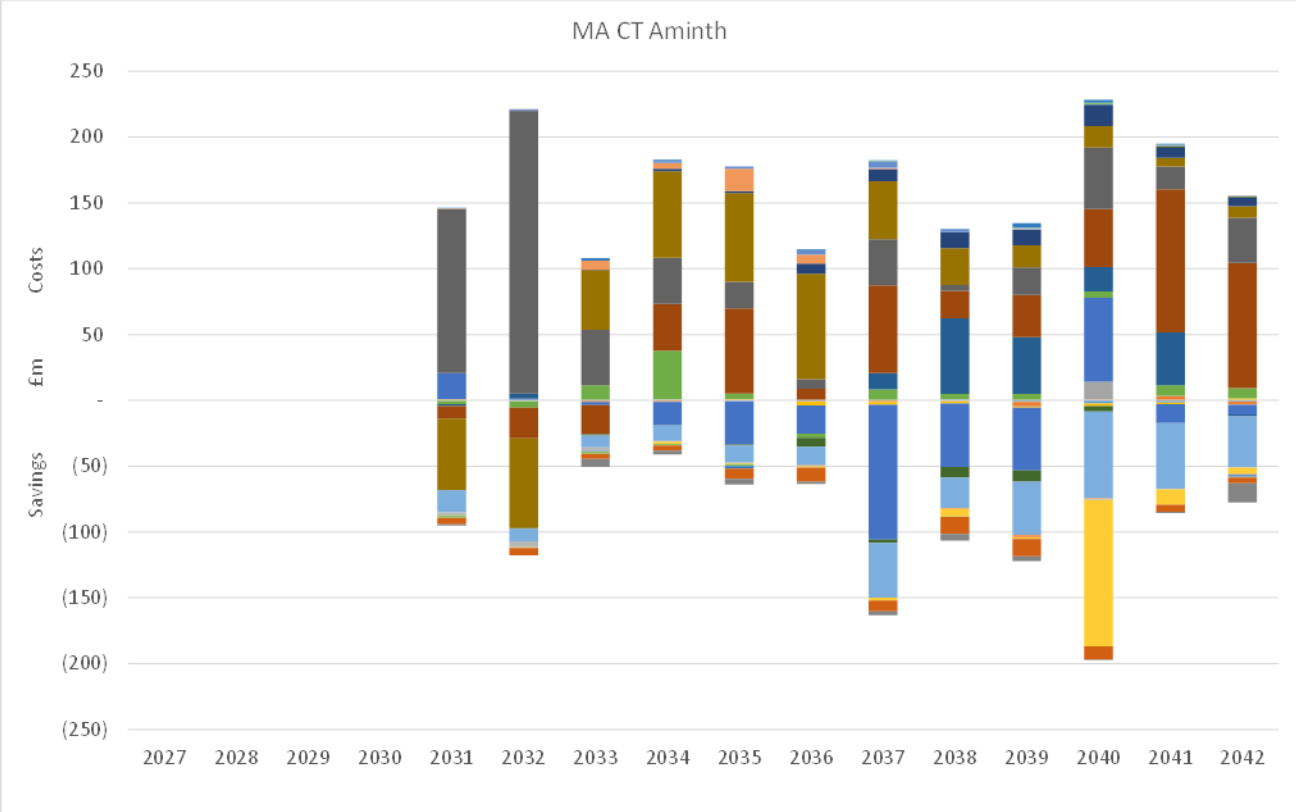

Figure 24: Change in constraint costs by boundary for Aminth for the Marginal Additional case for Consumer Transformation.

The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for Aminth for the Marginal Additional case for the Consumer Transformation scenario. Each different colour represents the change in constraint costs for a particular boundary. It is important to note that the chart shows changes in constraint costs by boundary, i.e. the difference between constraint costs when the project is included and when the project is excluded.

Compared to the First Additional case, the Marginal Additional shows an overall reduction in additional constraint costs each year, and an increase in constraint savings for each year. This is because the Marginal Additional case has all the W3 interconnector and OHA pilot projects included in the supply/demand background, enabling the model to minimise total constraint costs by taking balancing actions across the whole GB network for a wider range of solutions.

In general, for the Marginal Additional case, Aminth increases constraint costs on several northern and midland boundaries, but also relieves congestion on a range of boundaries. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

PV system operation

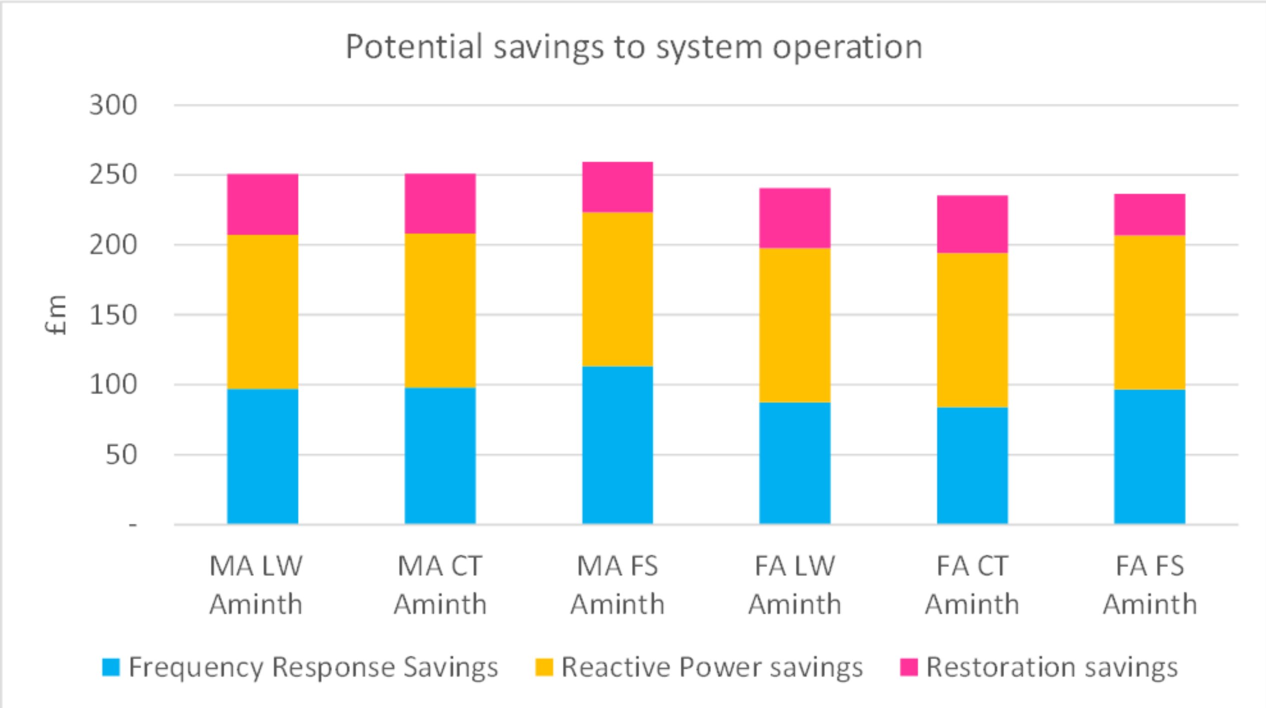

Figure 25: PV potential system operability savings for Aminth, Present Value 25-year, real 2022, £m.

The above figure shows the potential savings for frequency response, reactive power and restoration services in present value (25-year, 2022 £m) for Aminth for Leading the Way, Consumer Transformation and Falling Short for both the Marginal Additional and First Additional cases. There is considerable uncertainty around forecasting potential system operability benefits over a 25-year time horizon, but the figure shows that there is potentially significant savings in frequency response, reactive power and restoration services.

There is little variation across the three scenarios and also across the First Additional and Marginal Additional cases. This is because the potential system operability savings from the services provided by Aminth are less sensitive to flows across the interconnector, whereas the constraint cost impact is highly dependent on the scale and direction of flows across the project.

RES curtailment avoided

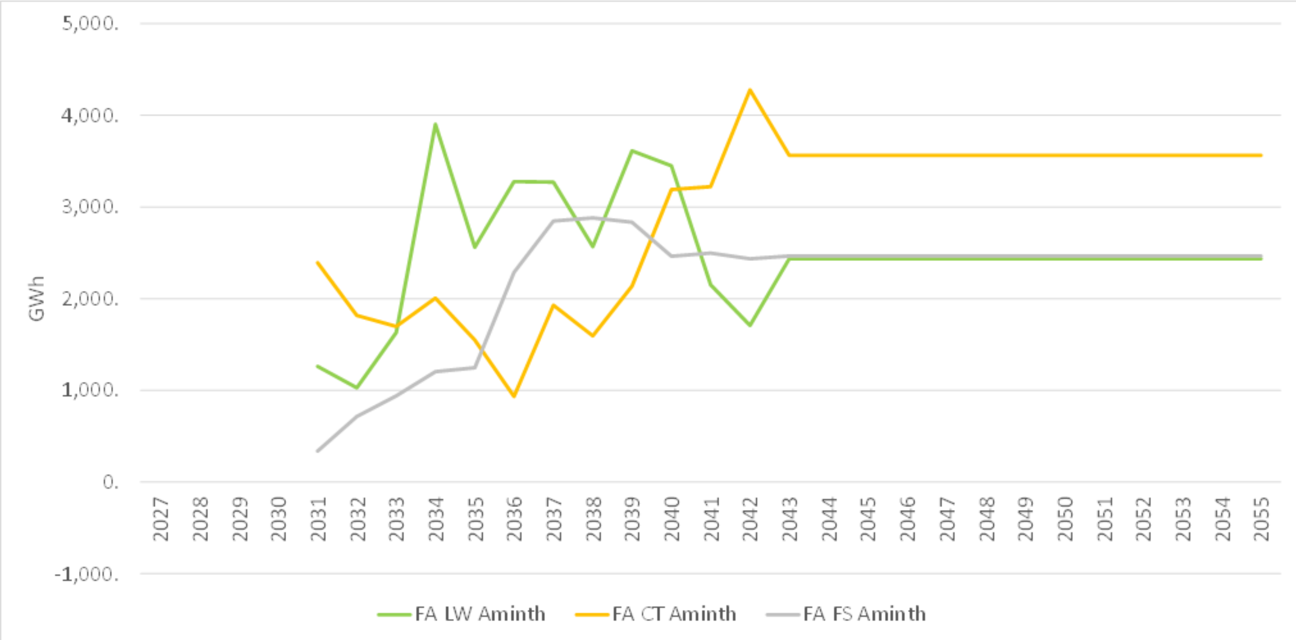

Figure 26: Annual RES curtailment avoided for Aminth for the First Additional case.

The above figure shows the renewable energy supply (RES) curtailment avoided on an annual basis for Leading the Way, Consumer Transformation and Falling Short for the First Additional case. Note that beyond 2042, the results are an average of the years 2040, 2041 and 2042, as our detailed modelling with FES22 only extends out to 2042. The figure shows that the level of annual RES curtailment avoided when Aminth is included is approximately between 1TWh and 3.5TWh, which equates to approximately between 2.7GWh and 9.6GWh per day.

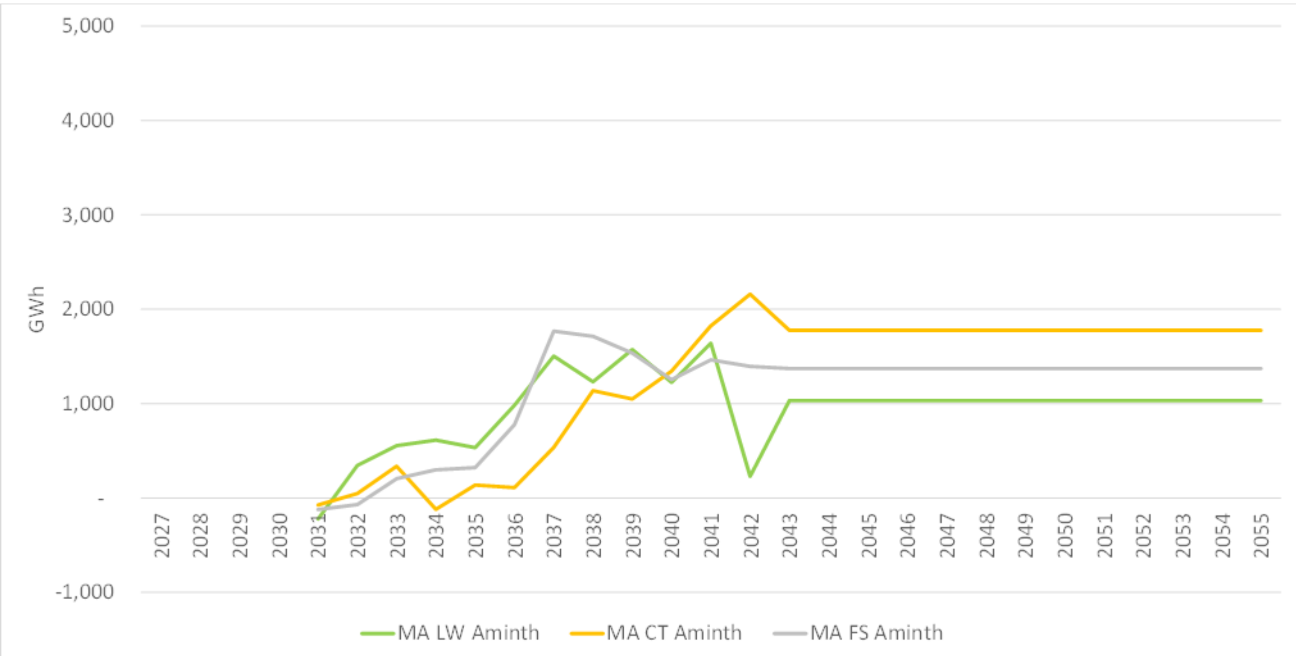

Figure 27: Annual RES curtailment avoided for Aminth for the Marginal Additional case.

The above figure shows the renewable energy supply (RES) curtailment avoided on an annual basis for Leading the Way, Consumer Transformation and Falling Short for the Marginal Additional case. Note that beyond 2042, the results are an average of the years 2040, 2041 and 2042, as our detailed modelling with FES22 only extends out to 2042. The figure shows that the level of annual RES curtailment avoided when Aminth is included rises to approximately between 0.5TWh and 2TWh, which equates to approximately between 1.4GWh and 5.5GWh per day.

11. AQUIND

AQUIND is a W3 interconnector project. It has a capacity of 2.0GW and connects to France.

PV constraint costs

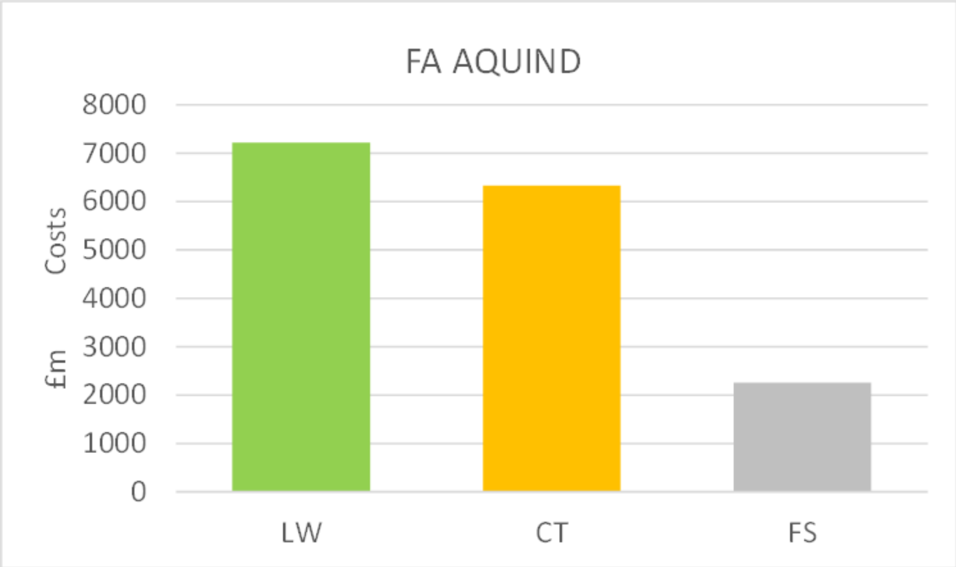

Figure 28: PV additional constraint costs for the First Additional case, Present Value 25-year, real 2022, £m.

The above figure shows that AQUIND results in an increase of approximately £6bn to £7bn in constraint costs in CT and LW in First Additional in PV terms over the 25-year life of the project. FS results in a significantly lower increase in constraint costs of approximately £2bn.

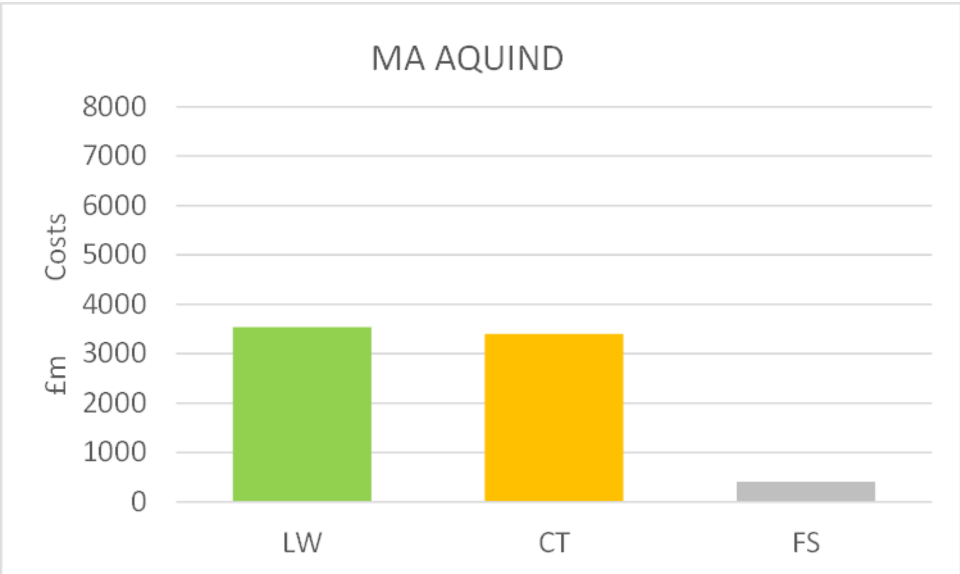

Figure 29: PV additional constraint costs for the Marginal Additional case, Present Value 25-year, real 2022, £m.

The above figure shows that AQUIND results in approximately a £3.5bn increase in constraint costs in CT and LW in the Marginal Additional case. FS results in approximately a £400m increase.

Annual constraint costs

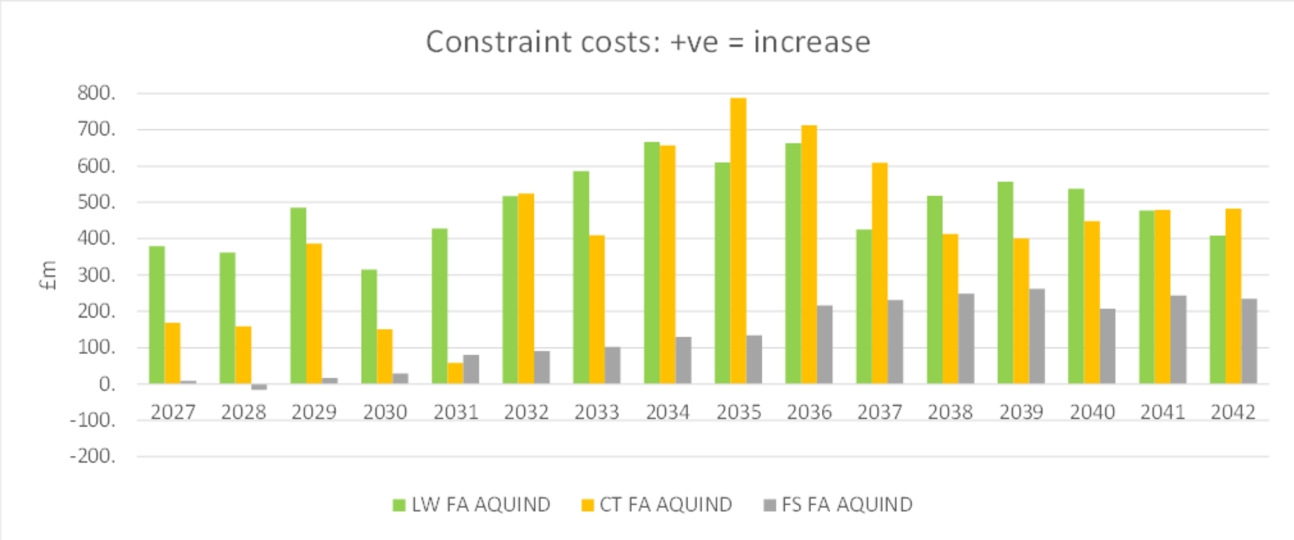

Figure 30: Additional annual constraint costs due to AQUIND for the First Additional case.

The above figure shows that in the First Additional case, AQUIND results in increased constraint costs of between £400m and £600m (undiscounted) between 2032 and 2042 in LW and CT. Constraints are very much lower in FS, with a small saving in 2028.

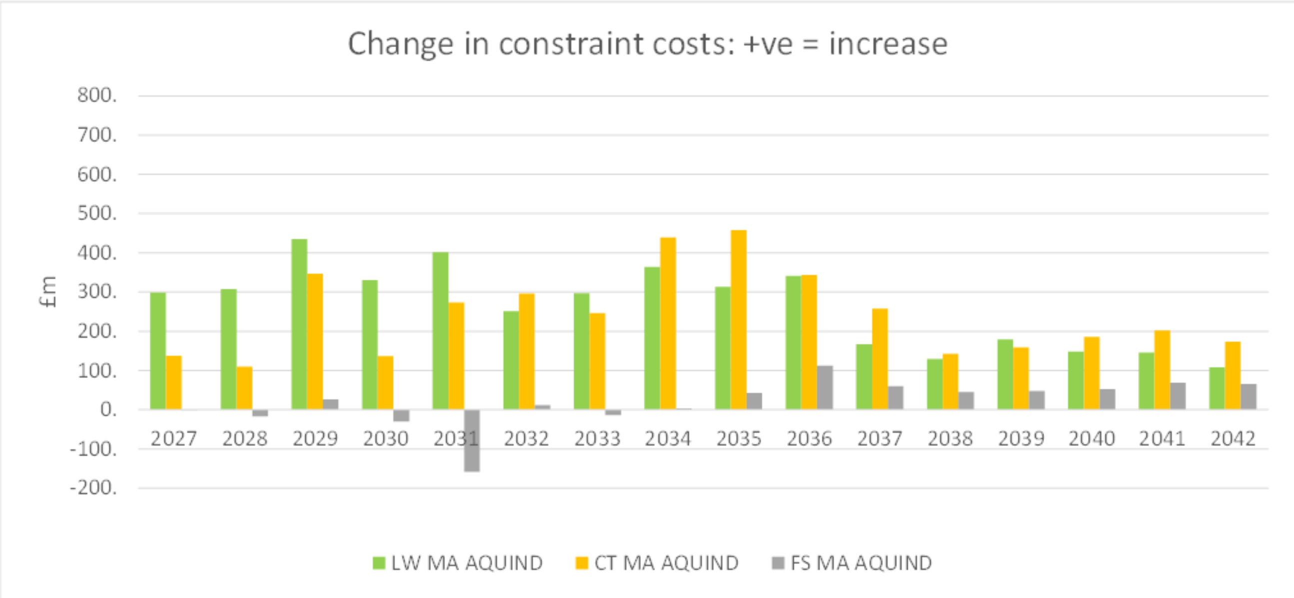

Figure 31: Additional annual constraint costs due to AQUIND for the Marginal Additional case.

The above figure shows that in the Marginal Additional case, AQUIND results in increased constraint costs of between £100m and £350m (undiscounted) in the mid-2030s in LW and CT. Constraints are much lower in FS, with savings in some years.

Annual import and export flows for dispatch and redispatch

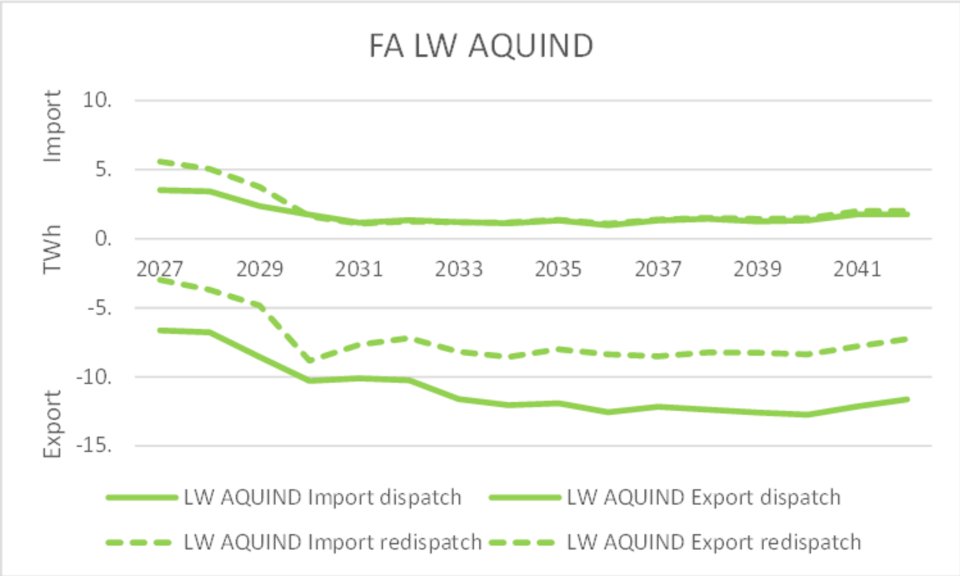

Figure 32: Annual import and export flows for AQUIND in the First Additional case for Leading the Way.

The above figure shows AQUIND has high exports and low imports in the dispatch for Leading the Way. The redispatch shows a significant reduction in exports and a small increase in imports in 2027 to 2029.

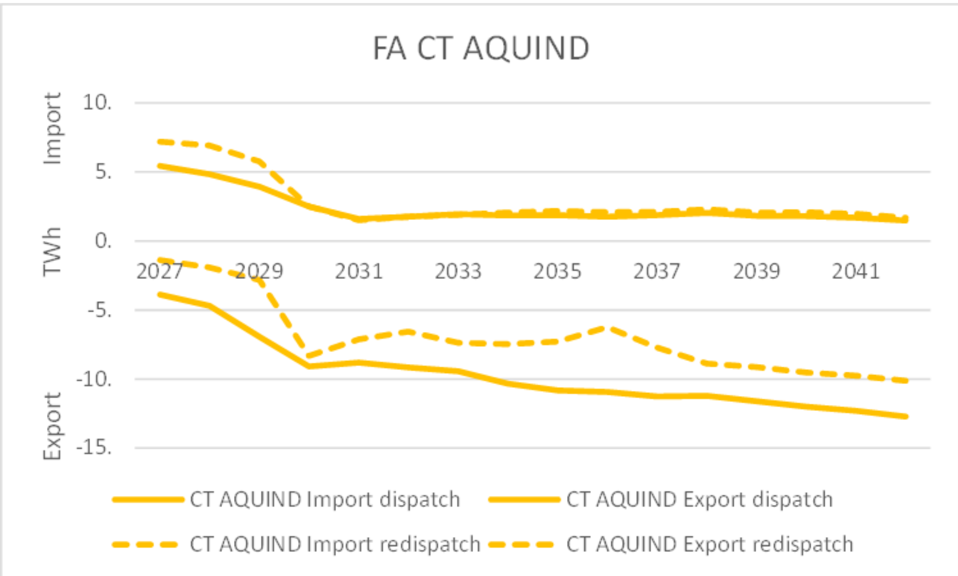

Figure 33: Annual import and export flows for AQUIND in the First Additional case for Consumer Transformation.

The above figure shows AQUIND has high exports and low imports in the dispatch for Consumer Transformation. The redispatch shows a significant reduction in exports and a small increase in imports in 2027 to 2029.

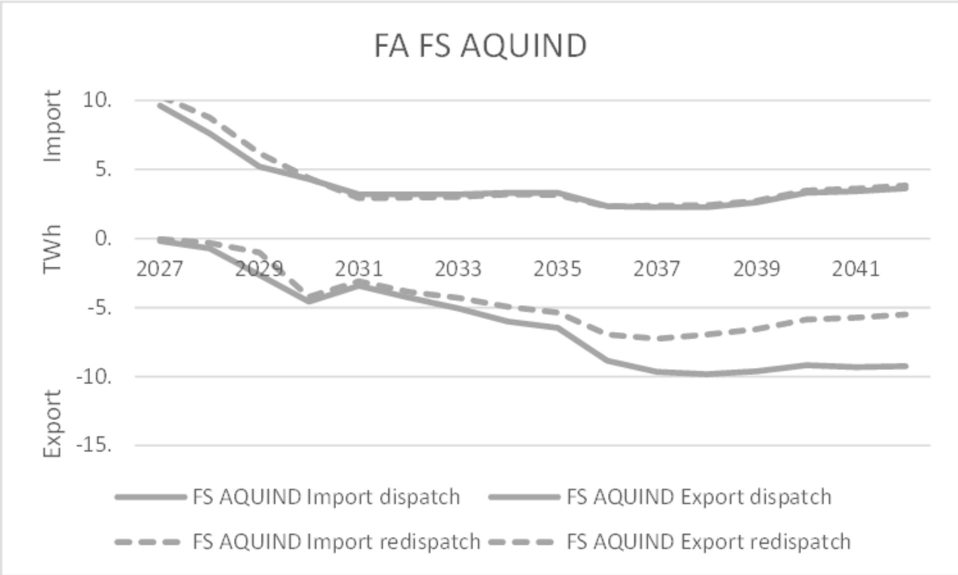

Figure 34: Annual import and export flows for AQUIND in the First Additional case for Falling Short.

The above figure shows AQUIND initially has low exports and high imports in the dispatch for Falling Short, with exports increasing over the years and imports decreasing. The redispatch shows a significant reduction in exports in the later years.

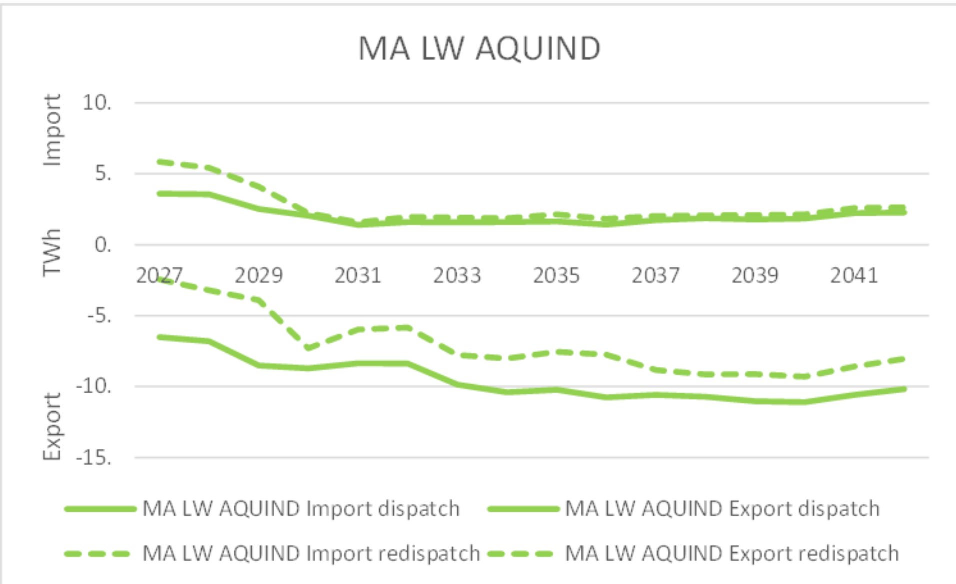

Figure 35: Annual import and export flows for AQUIND in the Marginal Additional case for Leading the Way.

The above figure shows AQUIND has high exports in the MA case, but lower that in the FA case for Leading the Way. Imports in the dispatch are low, near the levels seen in the FA case. The redispatch shows a significant reduction in exports, although not as high as in the FA case and a small increase in imports in 2027 to 2029.

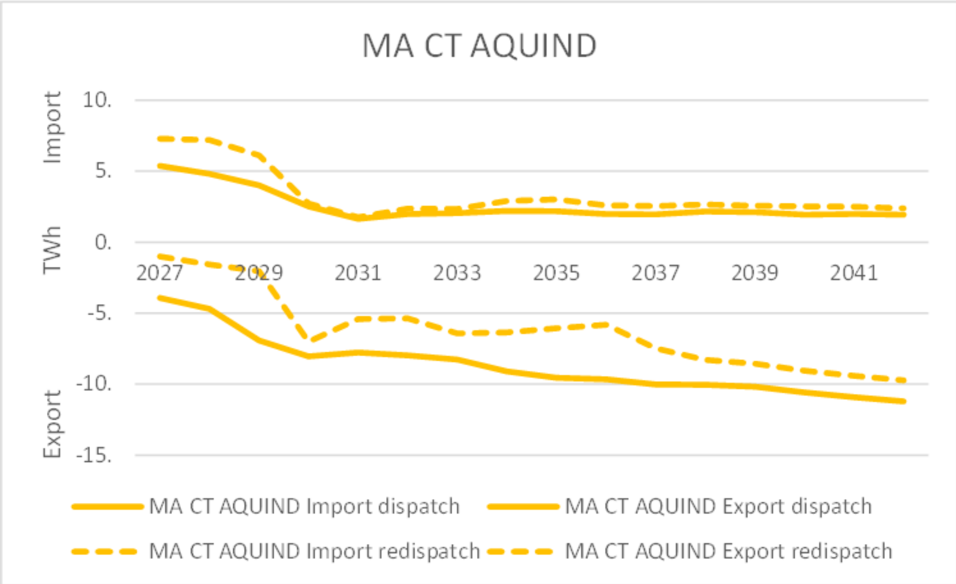

Figure 36: Annual import and export flows for AQUIND in the Marginal Additional case for Consumer Transformation.

Flows for AQUIND in the MA case for Consumer Transformation are very similar at an annual level to those seen in the FA case, for both the dispatch and redispatch, with high exports and low imports in the dispatch and reduced exports in the redispatch.

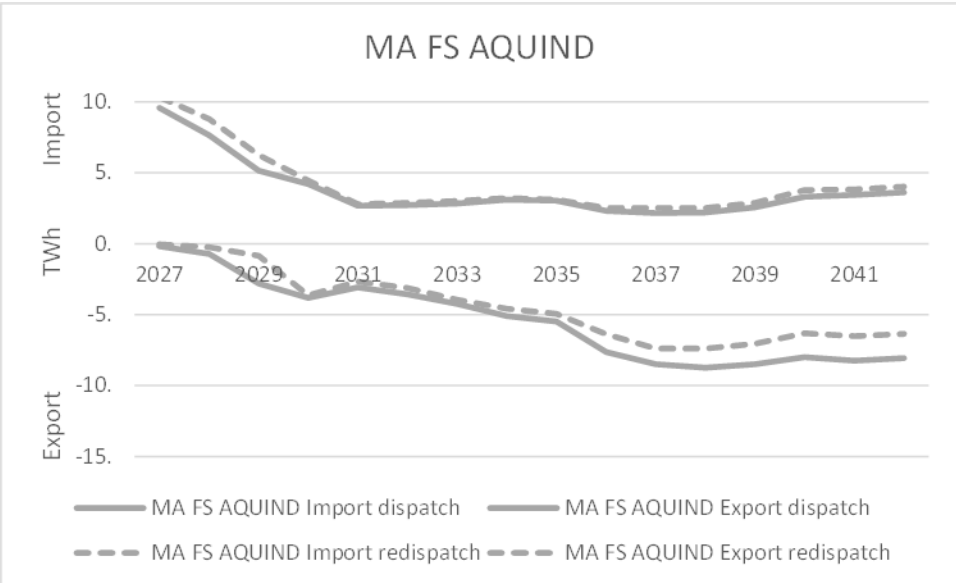

Figure 37: Annual import and export flows for AQUIND in the Marginal Additional case for Falling Short.

Flows for AQUIND in the MA case for Falling Short are very similar at an annual level to those seen in the FA case, for both the dispatch and redispatch, with increasing exports and reducing imports in the dispatch and reduced exports in the redispatch, although not as significant as in the FA case.

Change in constraint costs by boundary

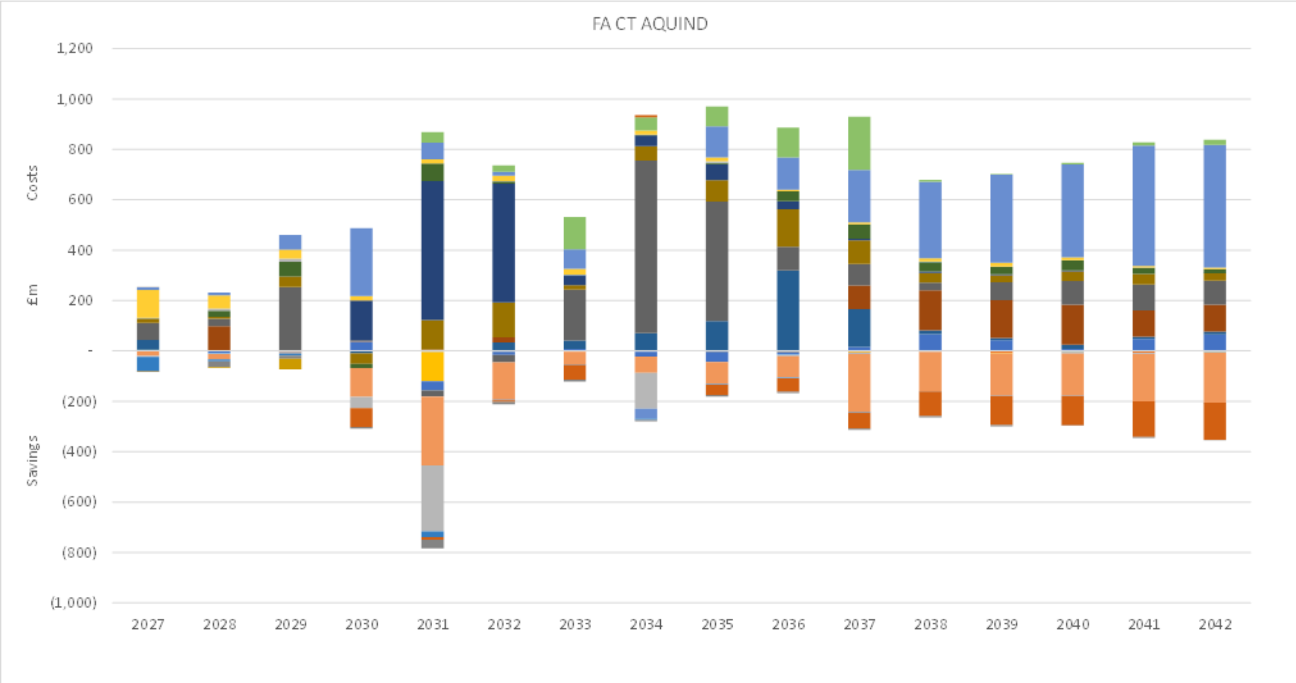

Figure 38: Change in constraint costs by boundary for AQUIND for the First Additional case for Consumer Transformation.

The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for AQUIND for the First Additional case for the Consumer Transformation scenario. Each different colour represents the change in constraint costs for a particular boundary. It is important to note that the chart shows changes in constraint costs by boundary, i.e. the difference between constraint costs when the project is included and when the project is excluded.

The figure shows that AQUIND increases constraint costs on certain boundaries but also reduces constraint costs on others. Whether the impact is an increase in constraint costs or a reduction in constraint costs for a particular boundary, changes from year to year. The size of change in constraint costs by boundary can also vary significantly from year to year. This is shown clearly in the years 2030 to 2032. The figure also shows that the specific boundaries that have the greatest impact on the total change in constraint costs can vary from year to year. These factors are a result of the changes in demand, supply and network capability over time.

In general, AQUIND increases constraint costs on several northern, midland and southern boundaries, but relieves congestion on certain southern boundaries. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

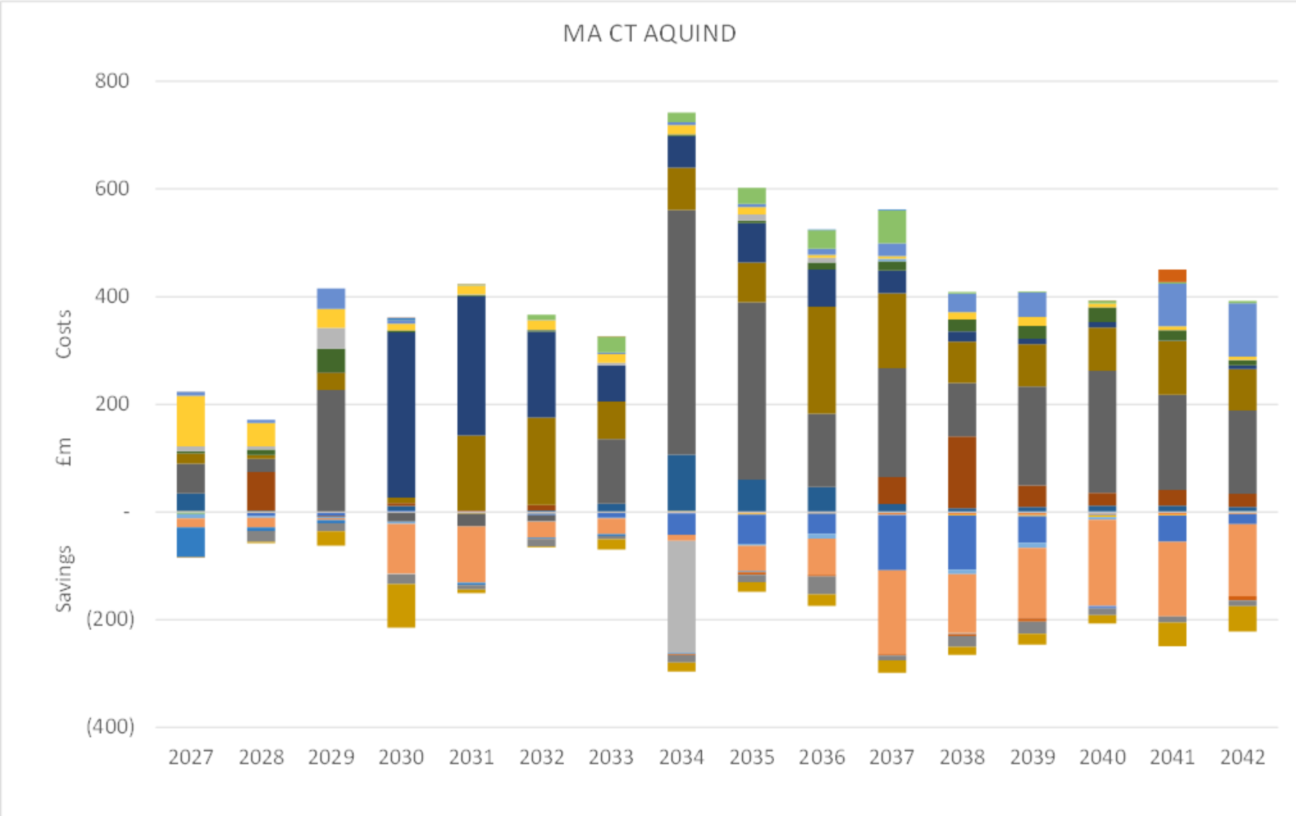

Figure 39: Change in constraint costs by boundary for AQUIND for the Marginal Additional case for Consumer Transformation.

The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for AQUIND for the Marginal Additional case for the Consumer Transformation scenario. Each different colour represents the change in constraint costs for a particular boundary. It is important to note that the chart shows changes in constraint costs by boundary, i.e. the difference between constraint costs when the project is included and when the project is excluded.

Compared to the First Additional case, the Marginal Additional case shows an overall reduction in additional constraint costs each year, but not such significant changes in constraint savings for each year. This is because the Marginal Additional case has all of the W3 interconnector and OHA pilot projects included in the supply/demand background, enabling the model to minimise total constraint costs by taking balancing actions across the whole GB network for a wider range of solutions.

In general, for the Marginal Additional case, AQUIND increases constraint costs on several northern, midland and southern boundaries, but also relieves congestion on several southern boundaries. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

PV system operation

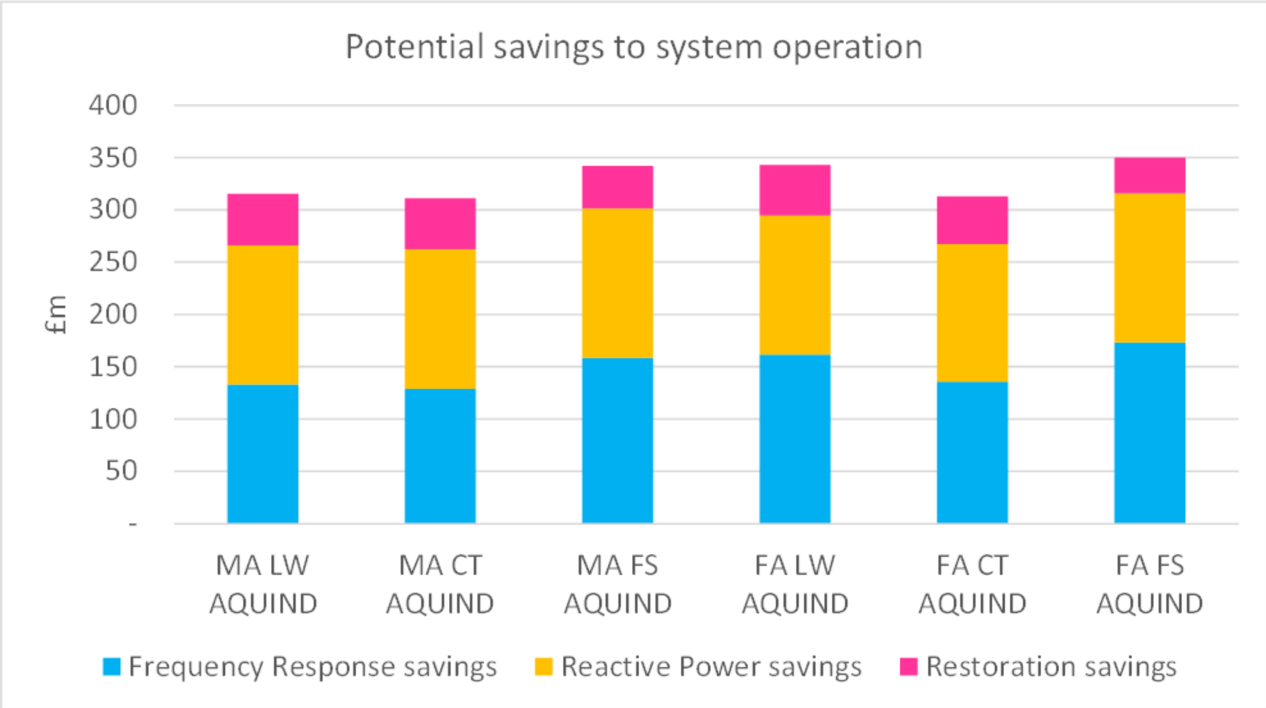

Figure 40: PV potential system operability savings for AQUIND, Present Value 25-year, real 2022, £m.

The above figure shows the potential savings for frequency response, reactive power and restoration services in present value (25-year, 2022 £m) for AQUIND for Leading the Way, Consumer Transformation and Falling Short for both the Marginal Additional and First Additional cases. There is considerable uncertainty around forecasting potential system operability benefits over a 25-year time horizon, but the figure shows that there is potentially significant savings in frequency response, reactive power and restoration services.

There is little variation across the three scenarios and also across the First Additional and Marginal Additional cases. This is because the potential system operability savings from the services provided by AQUIND are less sensitive to flows across the interconnector, whereas the constraint cost impact is highly dependent on the scale and direction of flows across the project.

RES curtailment avoided

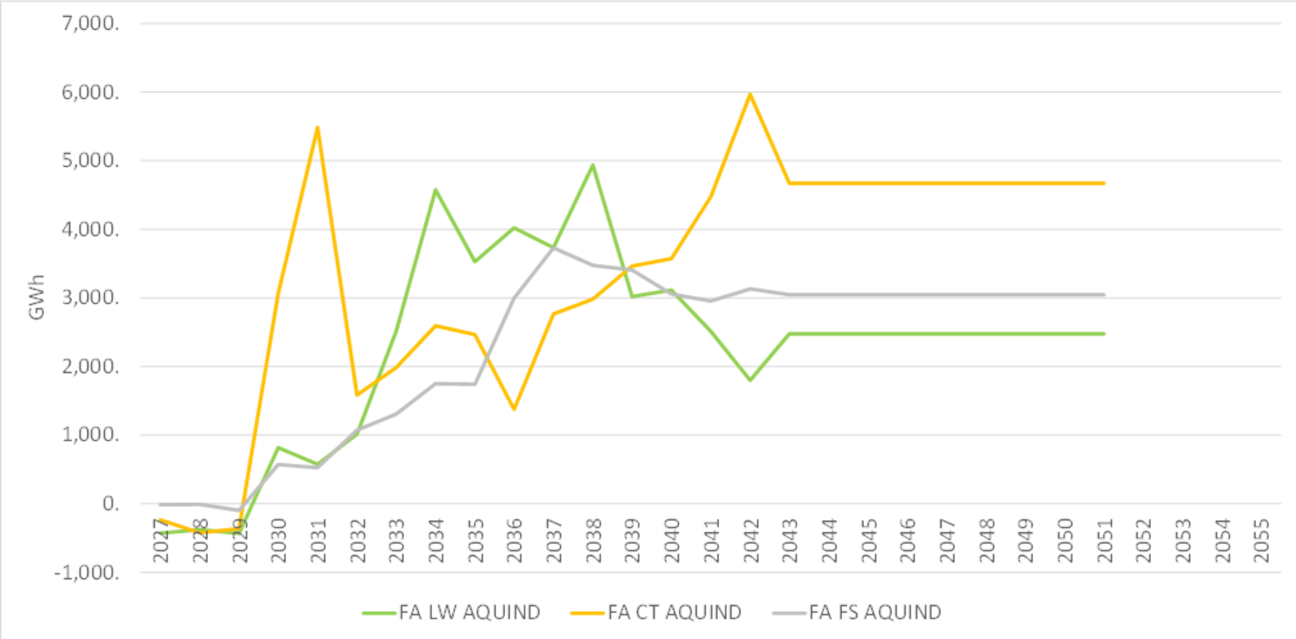

Figure 41: Annual RES curtailment avoided for AQUIND for the First Additional case.

The above figure shows the renewable energy supply (RES) curtailment avoided on an annual basis for Leading the Way, Consumer Transformation and Falling Short for the First Additional case. Note that beyond 2042, the results are an average of the years 2040, 2041 and 2042, as our detailed modelling with FES22 only extends out to 2042. The figure shows that the level of annual RES curtailment avoided when AQUIND is included (excluding the first two years) is approximately between 1TWh and 5TWh, which equates to approximately between 2.7GWh and 13.7GWh per day.

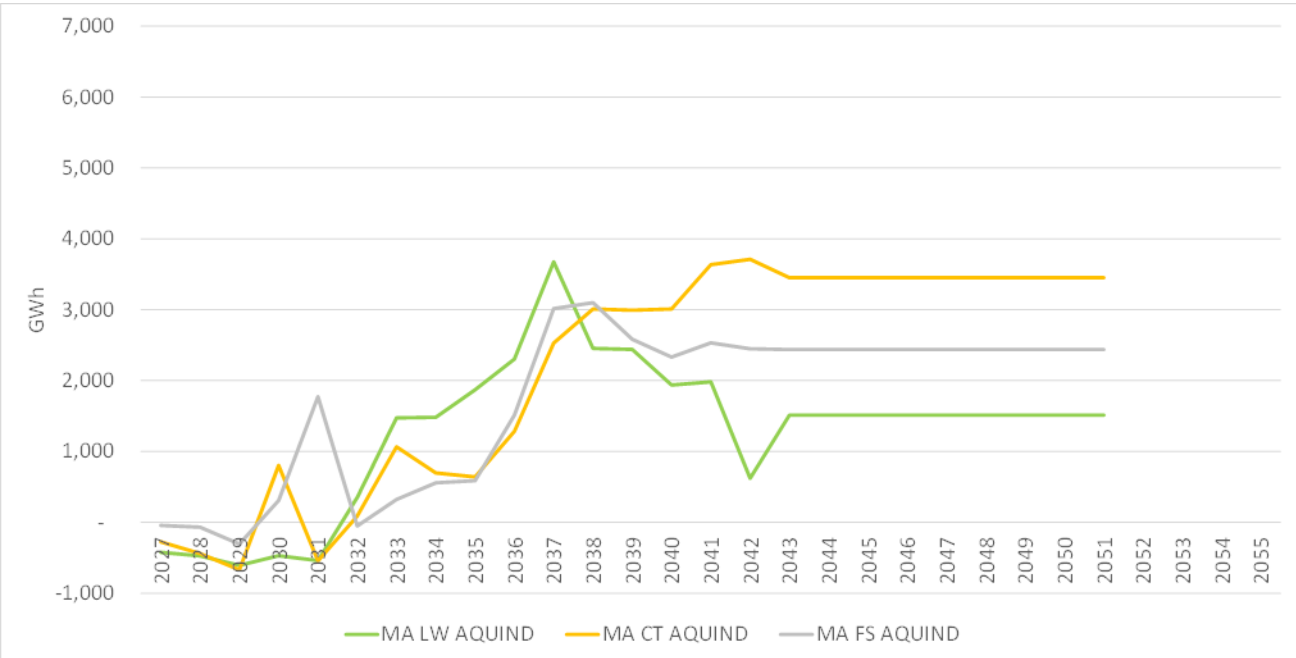

Figure 42: Annual RES curtailment avoided for AQUIND for the Marginal Additional case.

The above figure shows the renewable energy supply (RES) curtailment avoided on an annual basis for Leading the Way, Consumer Transformation and Falling Short for the Marginal Additional case. Note that beyond 2042, the results are an average of the years 2040, 2041 and 2042, as our detailed modelling with FES22 only extends out to 2042. The figure shows that the level of annual RES curtailment avoided when AQUIND is included (excluding the first two years) is approximately between 0.5TWh and 3.5TWh, which equates to approximately between 1.4GWh and 9.6GWh per day.

12. Cronos

Cronos is a W3 interconnector project. It has a capacity of 1.4GW and connects to Belgium.

PV constraint costs

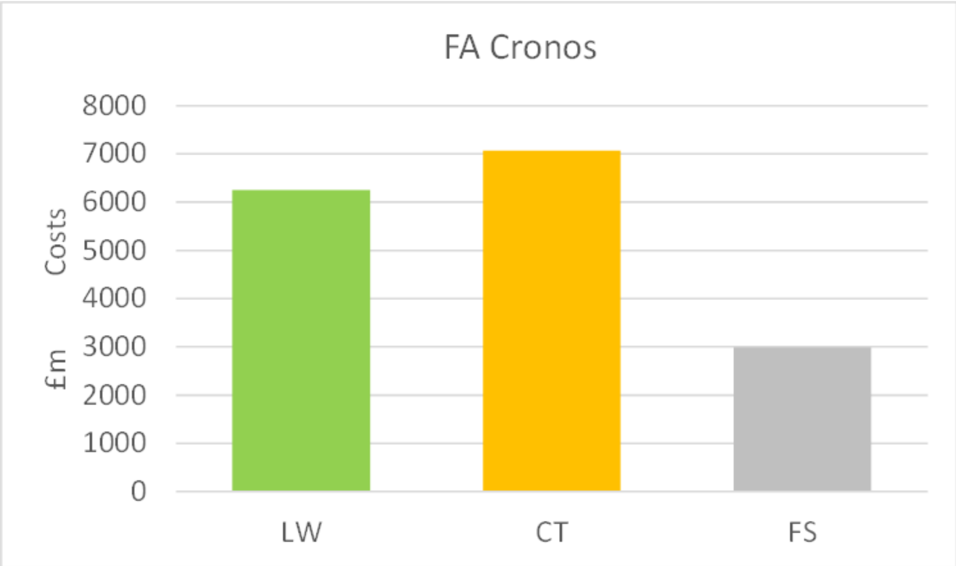

Figure 43: PV additional constraint costs due to Cronos for the First Additional case, Present Value 25-year, real 2022, £m.

The above figure shows the additional constraint costs with the inclusion of Cronos for the FA case. In the Leading the Way scenario (LW) constraint costs are increased by approximately £6bn, in Consumer Transformation (CT) by £7bn and in the Falling Short (FS) scenario by £3bn.

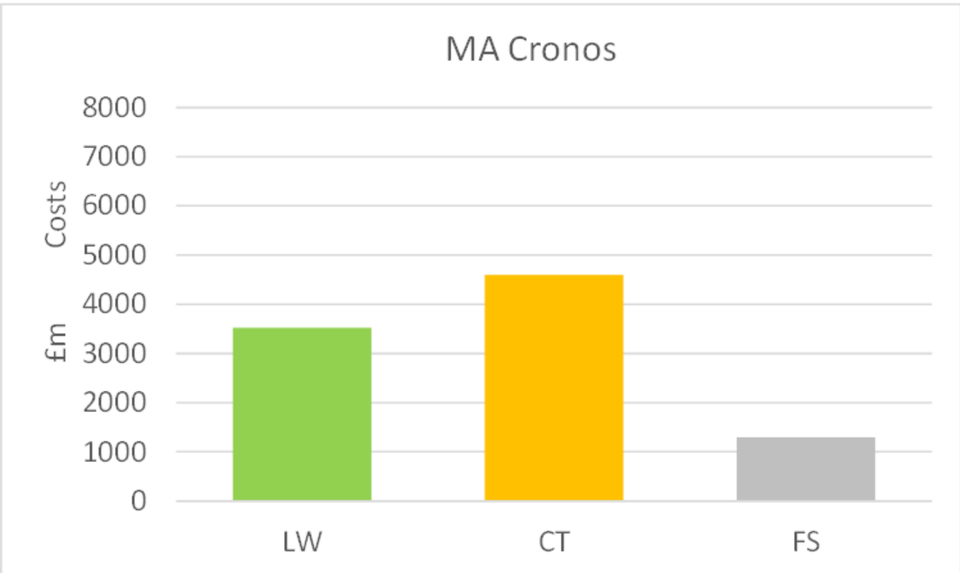

Figure 44: PV additional constraint costs due to Cronos for the Marginal Additional case, Present Value 25-year, real 2022, £m.

The above figure shows the additional constraint costs with the inclusion of Cronos for the MA case. Additional constraint costs are significantly lower than in the FA case. This is because the inclusion of the other OHA and Window 3 projects within the supply demand mix reduces the impact any one interconnector has on constraint costs. In the Leading the

Way scenario (LW) constraint costs are increased by approximately £3.5bn, in Consumer Transformation (CT) by £4.6bn and in the Falling Short (FS) scenario by £1.3bn.

Annual constraint costs

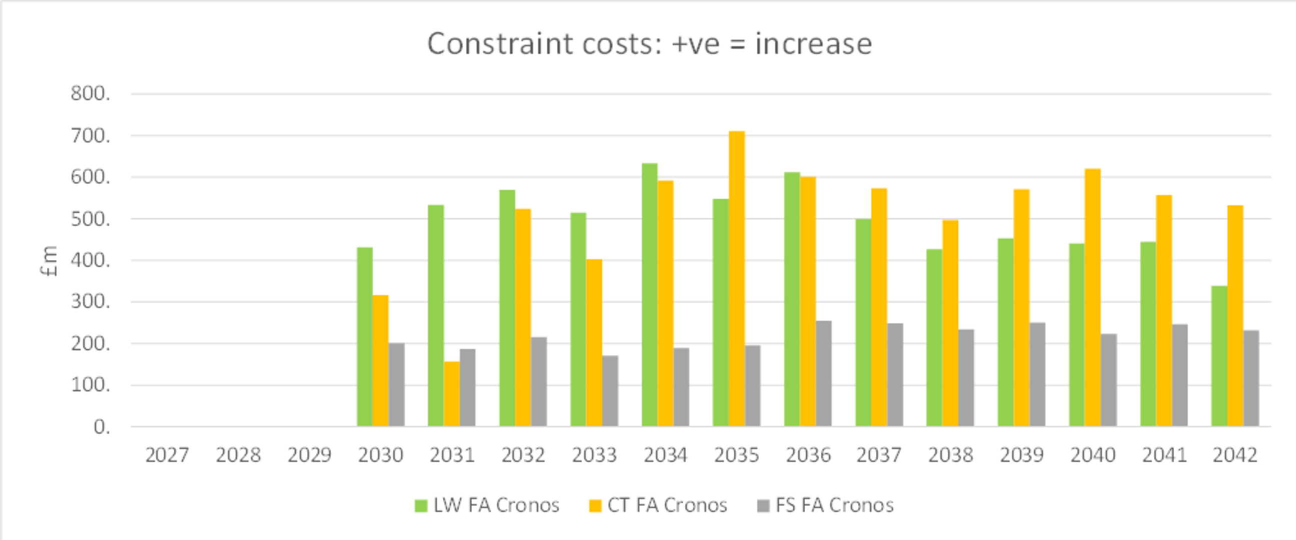

Figure 45: Additional annual constraint costs due to Cronos for the First Additional case.

The above figure shows that for the First Additional case, Cronos results in an increase in constraint costs of between £400m and £600m (undiscounted) in CT and LW in the years from 2032 to 2041. In FS constraint cost increases are much lower, at approximately £200m (undiscounted) each year.

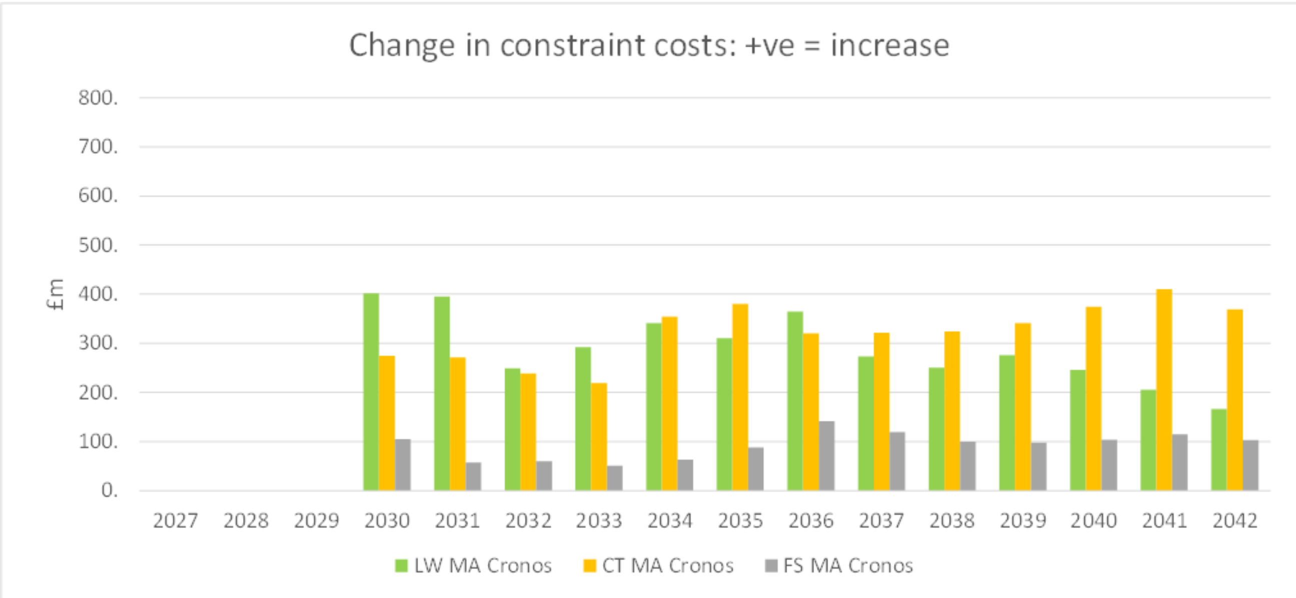

Figure 46: Additional annual constraint costs due to Cronos for the Marginal Additional case.

The above figure shows that for the Marginal Additional case, Cronos results in an increase in constraint costs of between £200m and £400m (undiscounted) in CT and LW for the years 2030 to 2040. In FS constraint cost increases are much lower, at approximately £100m (undiscounted) each year.

Annual import and export flows for dispatch and redispatch

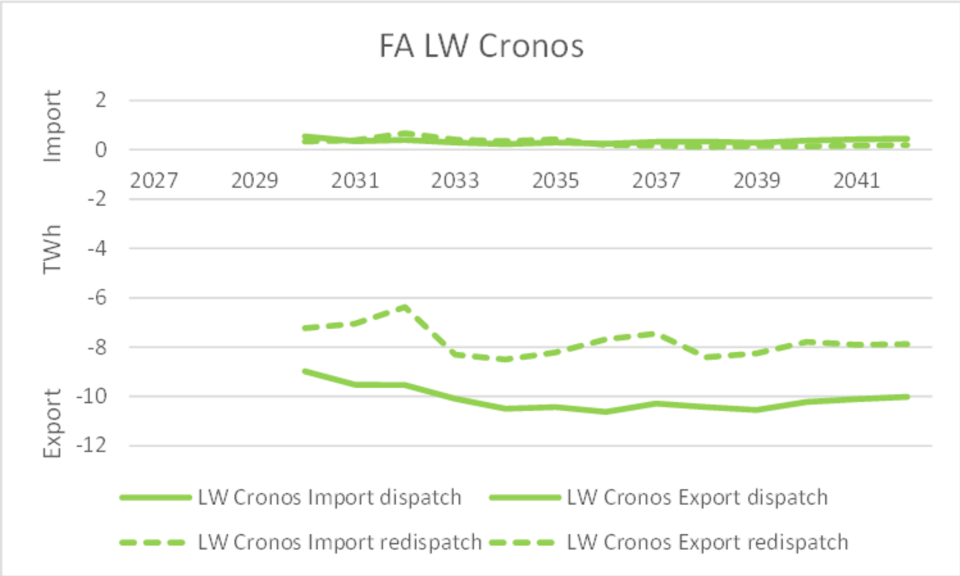

Figure 47: Annual import and export flows for Cronos in the FA case for Leading the Way.

The above figure shows Cronos has high exports and very low imports in the dispatch for Leading the Way for the First Additional case. The redispatch shows a significant reduction in exports and only very small changes in imports.

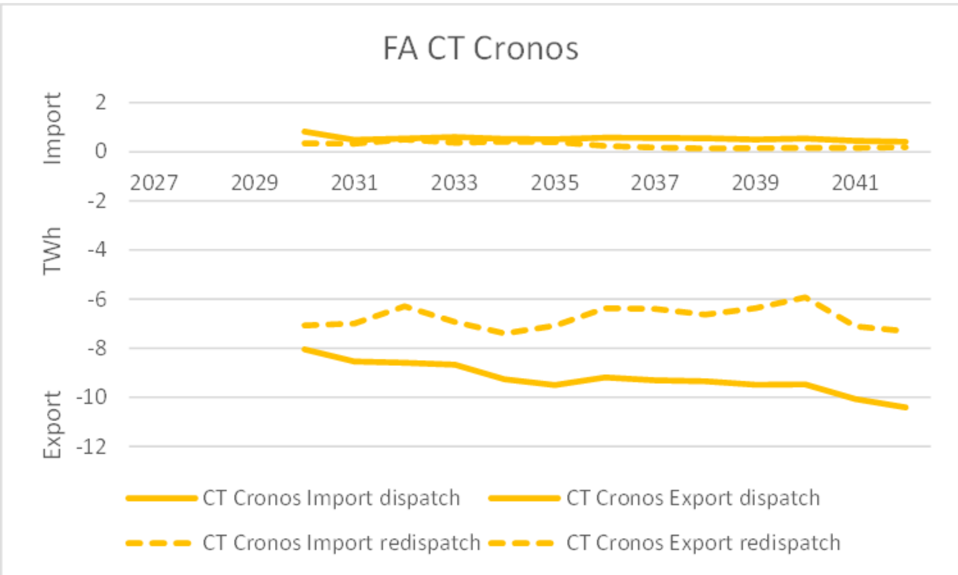

Figure 48: Annual import and export flows for Cronos in the FA case for Consumer Transformation.

The above figure shows Cronos has high exports and very low imports in the dispatch for Consumer Transformation for the First Additional case. The redispatch shows a significant reduction in exports and only very small reductions in imports in the later years.

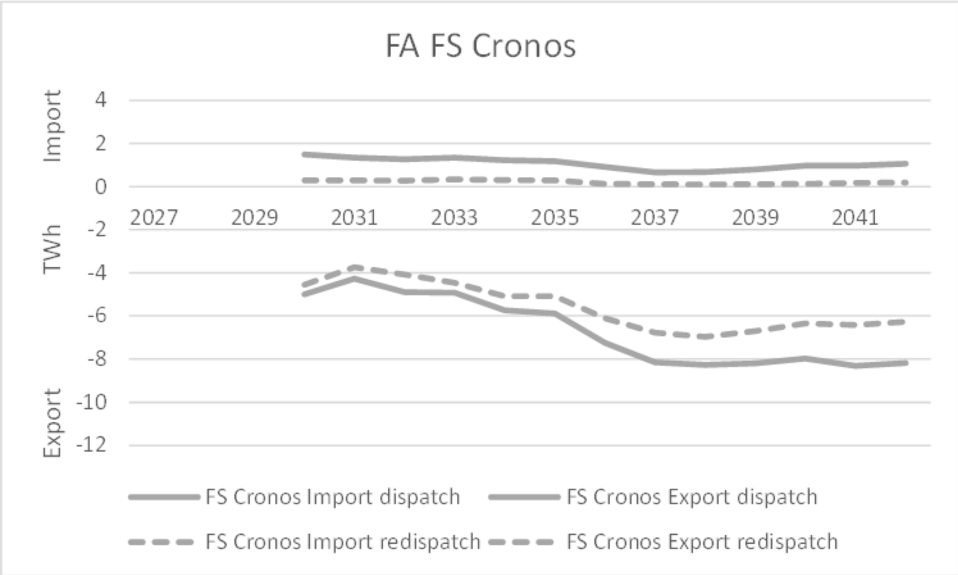

Figure 49: Annual import and export flows for Cronos in the FA case for Falling Short.

The above figure shows Cronos has increasing exports and low imports in the dispatch for Falling Short for the First Additional case. The redispatch shows increasing reductions in exports over time and imports are reduced to nearly zero for all years.

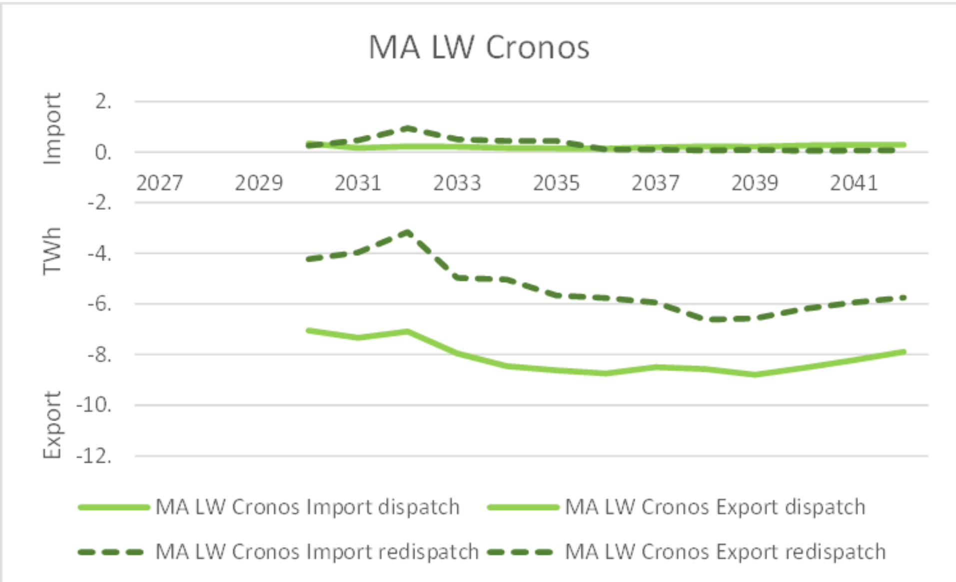

Figure 50: Annual import and export flows for Cronos in the MA case for Leading the Way.

The above figure shows Cronos has high exports and very low imports in the dispatch for Leading the Way for the Marginal Additional case. The redispatch shows a very significant reduction in exports (nearly a halving in the early years) and only minor changes in imports.

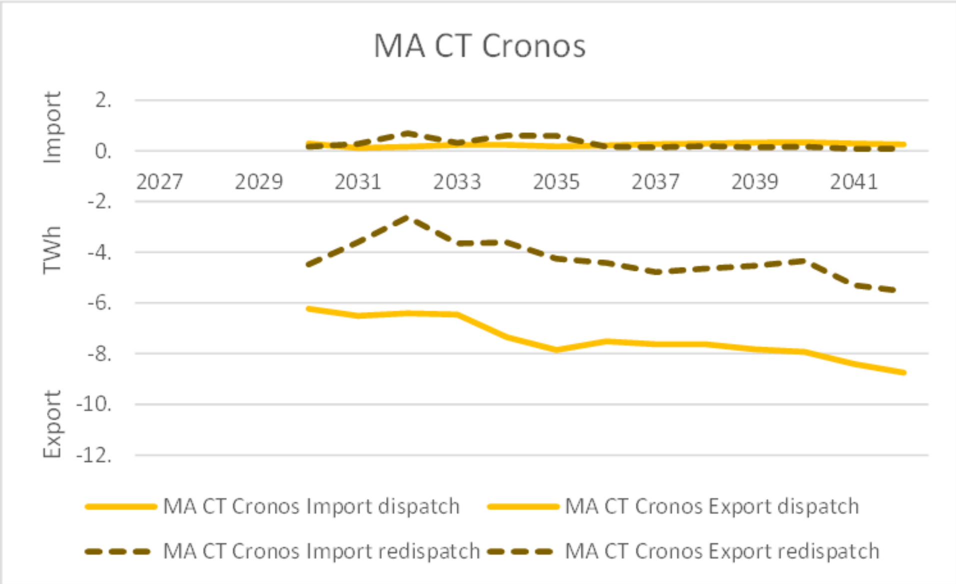

Figure 51: Annual import and export flows for Cronos in the MA case for Consumer Transformation.

The above figure shows Cronos has high exports and very low imports in the dispatch for Consumer Transformation for the Marginal Additional case. The redispatch shows a very significant reduction in exports (nearly a halving in the mid-2030s) and only minor changes in imports.

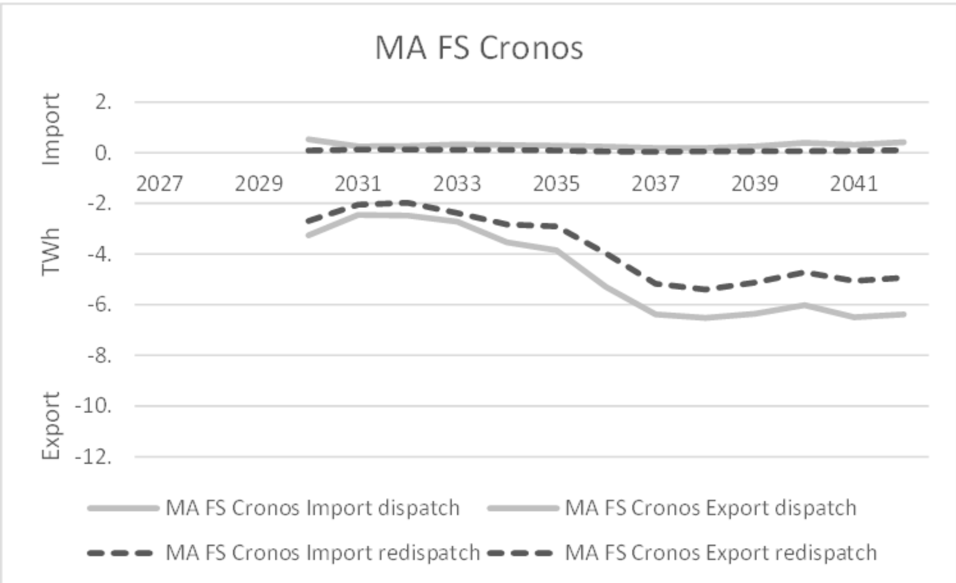

Figure 52: Annual import and export flows for Cronos in the MA case for Falling Short.

The above figure shows Cronos has increasing exports and very low imports in the dispatch for Falling Short for the Marginal Additional case. The redispatch shows increased reductions in exports over time and the very low levels of imports are reduced even further to nearly zero.

Change in constraint costs by boundary

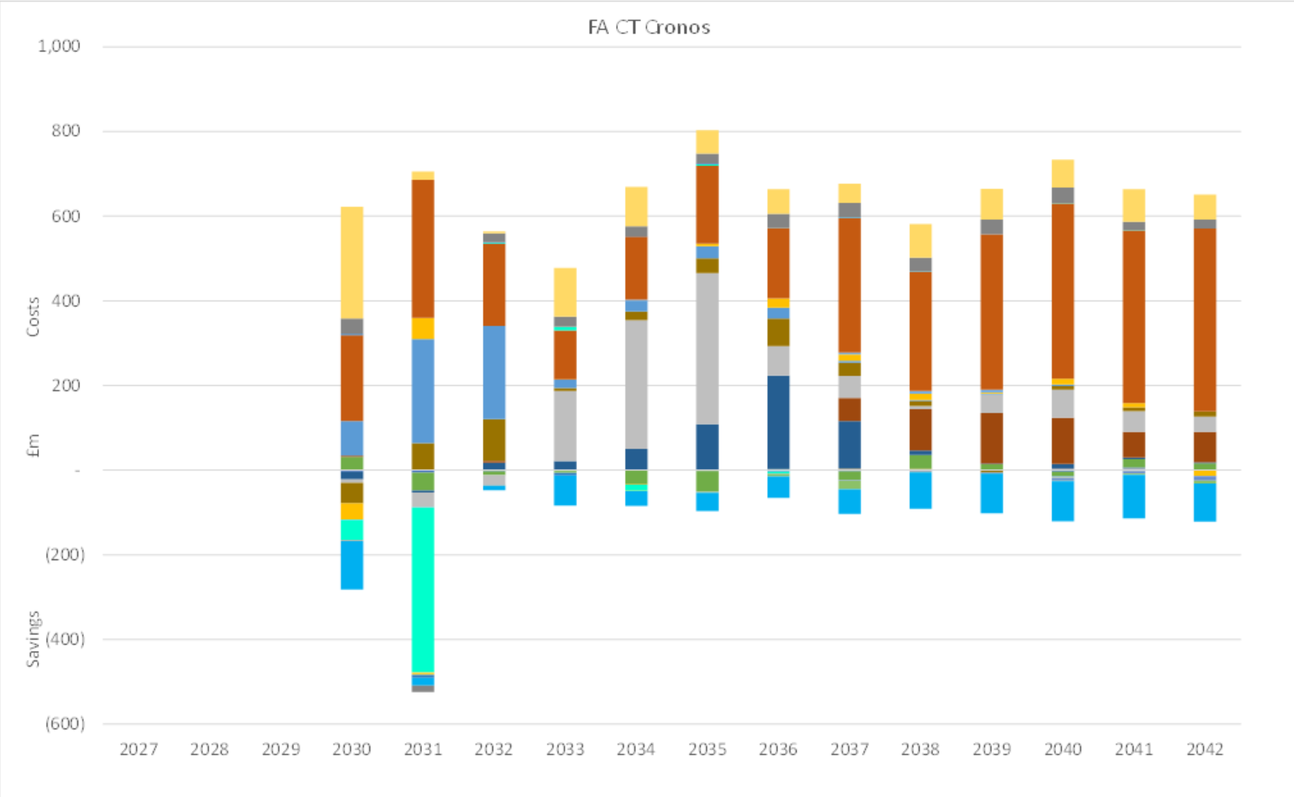

Figure 53: Change in constraint costs by boundary for Cronos for the FA case for Consumer Transformation.

The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for Cronos for the First Additional case for the Consumer Transformation scenario. Each different colour represents the change in constraint costs for a particular boundary. It is important to note that the chart shows changes in constraint costs by boundary, i.e. the difference between constraint costs when the project is included and when the project is excluded.

The figure shows that Cronos increases constraint costs on certain boundaries but also reduces constraint costs on others, in particular a Welsh boundary in 2031 (shown in turquoise). The size of change in constraint costs by boundary can also vary significantly from year to year. This is shown clearly in the years 2030 to 2032. The figure also shows that the specific boundaries that have the greatest impact on the total change in constraint costs can also vary from year to year. These factors are a result of the changes in demand, supply and network capability over time.

In general, Cronos increases constraint costs on several northern, midland and southern boundaries. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

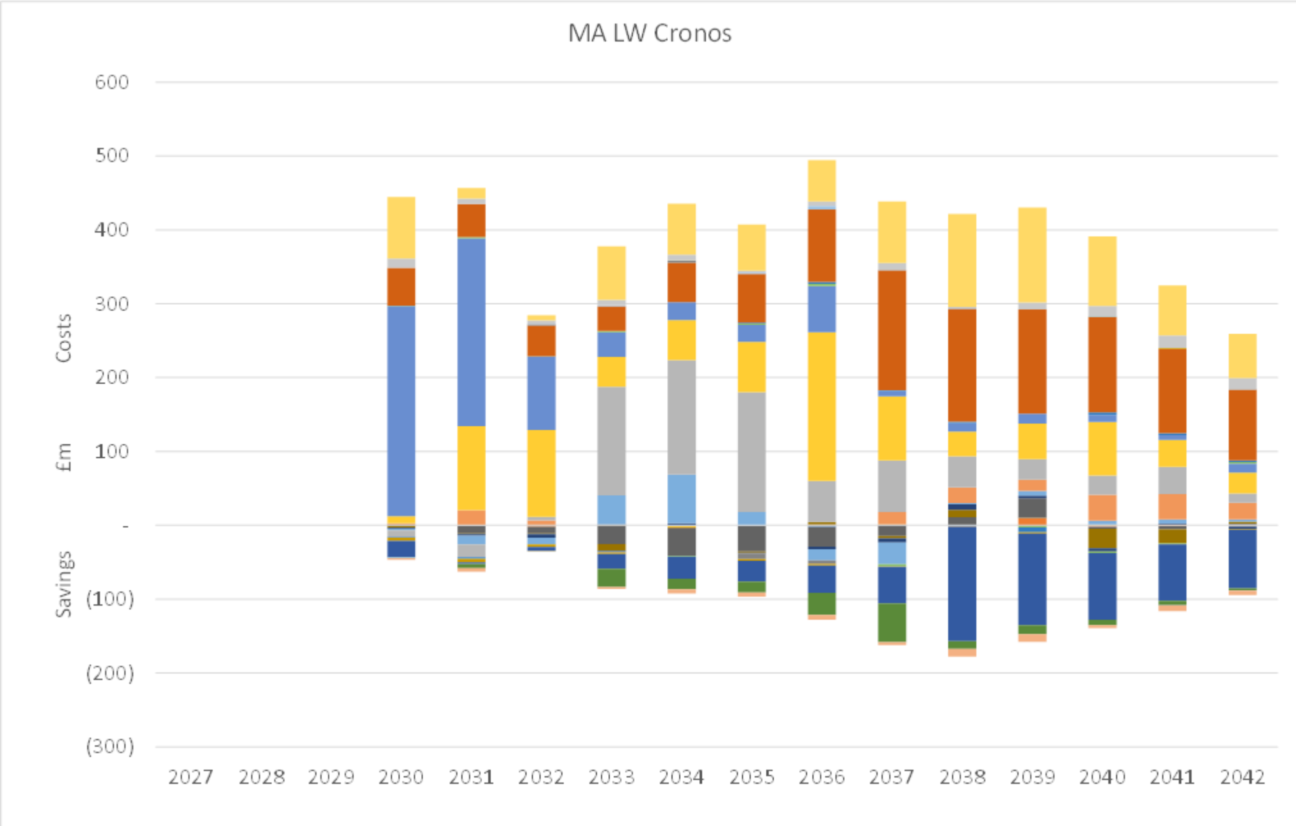

Figure 54: Change in constraint costs by boundary for Cronos for the MA case for Leading the Way.

The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for Cronos for the Marginal Additional case for the Leading the Way scenario. Each different colour represents the change in constraint costs for a particular boundary. It is important to note that the chart shows changes in constraint costs by boundary, i.e. the difference between constraint costs when the project is included and when the project is excluded.

Compared to the First Additional case, the Marginal Additional shows an overall reduction in additional constraint costs each year, and a slight increase in constraint savings for each year. This is because the Marginal Additional case has all of the W3 interconnector and OHA pilot projects included in the supply/demand background, enabling the model to minimise total constraint costs by taking balancing actions across the whole GB network for a wider range of solutions.

In general, for the Marginal Additional case, Cronos increases constraint costs on several midland and southern boundaries, but also relieves congestion on several boundaries. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

PV system operation

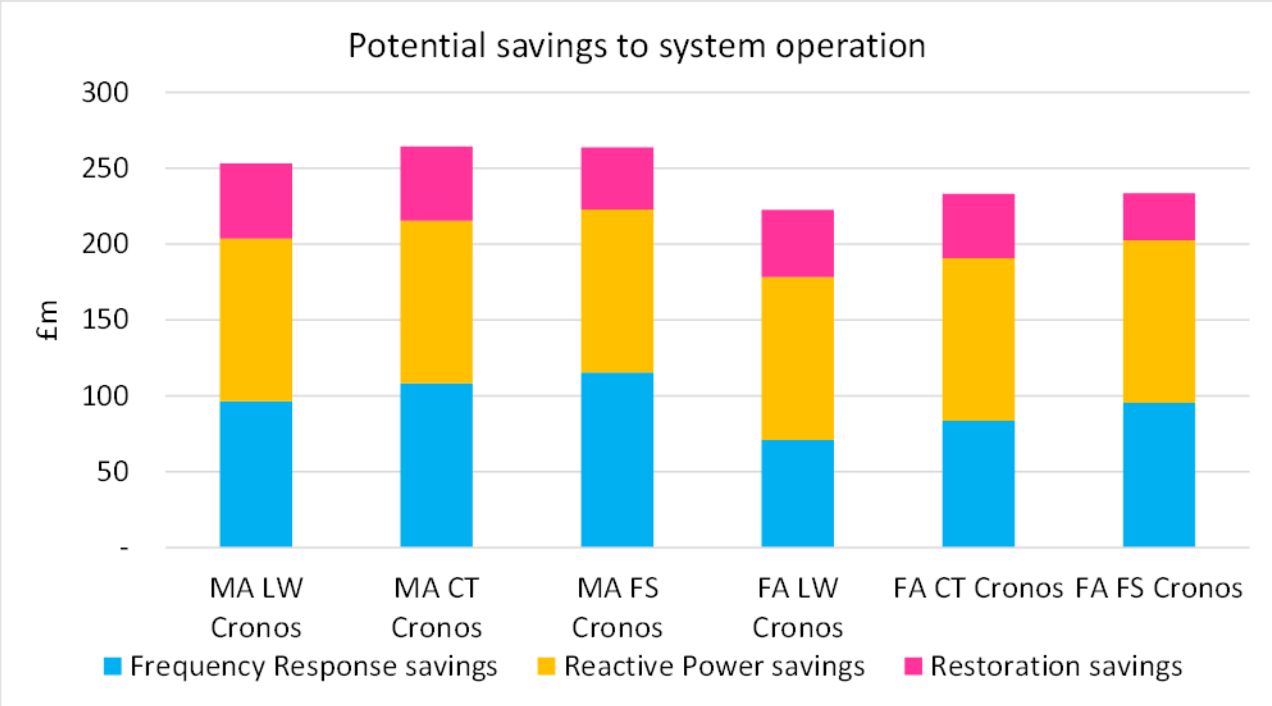

Figure 55: PV potential system operability savings for Cronos, Present Value 25-year, real 2022, £m.

The above figure shows the potential savings for frequency response, reactive power and restoration services in present value (25 year, 2022 £m) for Cronos for Leading the Way, Consumer Transformation and Falling Short for both the Marginal Additional and First Additional cases. There is considerable uncertainty around forecasting potential system operability benefits over a 25-year time horizon, but the figure shows that there is potentially significant savings in frequency response, reactive power and restoration services.

There is little variation across the three scenarios and also across the First Additional and Marginal Additional cases. This is because the potential system operability savings from the services provided by Cronos are less sensitive to flows across the interconnector, whereas the constraint cost impact is highly dependent on the scale and direction of flows across the project.

RES curtailment avoided

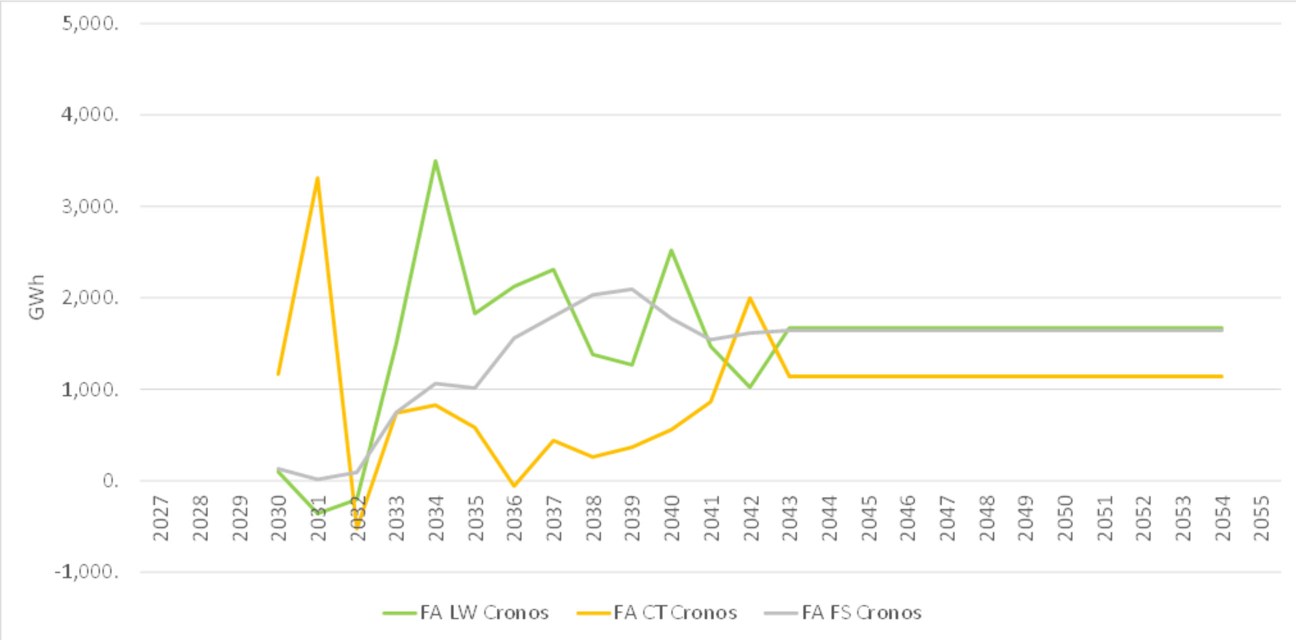

Figure 56: Annual RES curtailment avoided for Cronos for the First Additional case.

The above figure shows the renewable energy supply (RES) curtailment avoided on an annual basis for Leading the Way, Consumer Transformation and Falling Short for the First Additional case. Note that beyond 2042, the results are an average of the years 2040, 2041 and 2042, as our detailed modelling with FES22 only extends out to 2042. The figure shows that the level of annual RES curtailment avoided when Cronos is included is approximately between 0.5TWh and 2TWh, which equates to approximately between 1.4GWh and 5.5GWh per day.

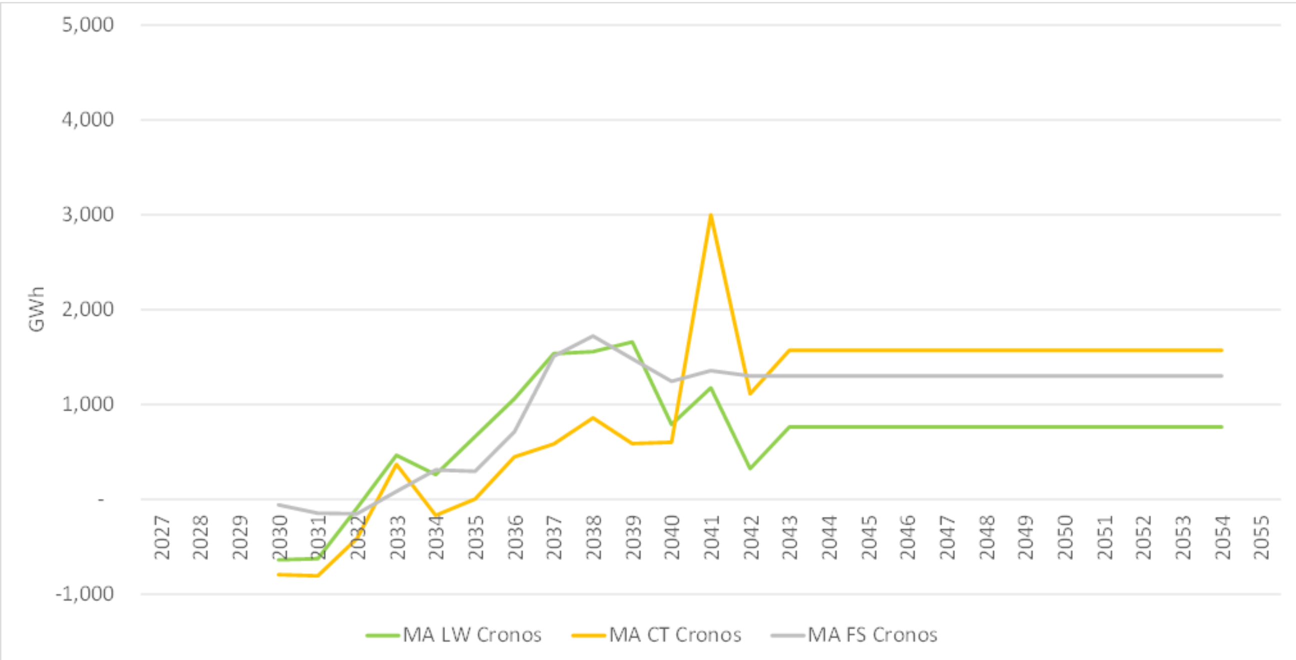

Figure 57: Annual RES curtailment avoided for Cronos for the Marginal Additional case.

The above figure shows the renewable energy supply (RES) curtailment avoided on an annual basis for Leading the Way, Consumer Transformation and Falling Short for the Marginal Additional case. Note that beyond 2042, the results are an average of the years 2040, 2041 and 2042, as our detailed modelling with FES22 only extends out to 2042. The figure shows that the level of annual RES curtailment avoided when Cronos is included is approximately between 0.5TWh and 1.5TWh, which equates to approximately between 1.4GWh and 4.1GWh per day.

13. LionLink

LionLink is an Offshore Hybrid Asset (OHA) pilot project. It has a capacity of 1.8GW and connects to The Netherlands.

PV constraint costs

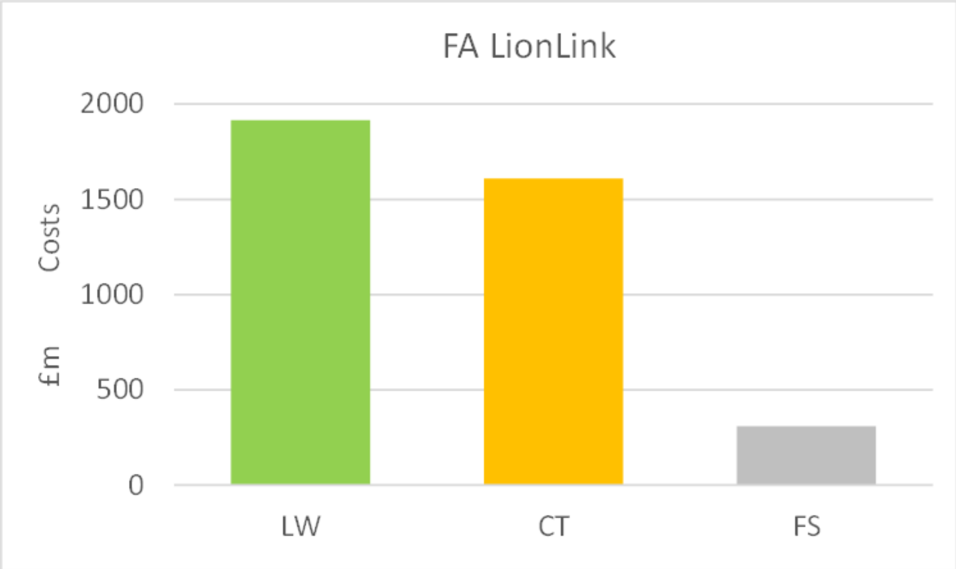

Figure 58: PV additional constraint costs due to LionLink for the First Additional case, Present Value 25-year, real 2022, £m.

The above figure shows the additional constraint costs with the inclusion of LionLink for the FA case. In the Leading the Way (LW) scenario constraint costs are increased by £1.9bn, in Consumer Transformation (CT) by £1.6bn and in the Falling Short (FS) scenario by £0.3bn.

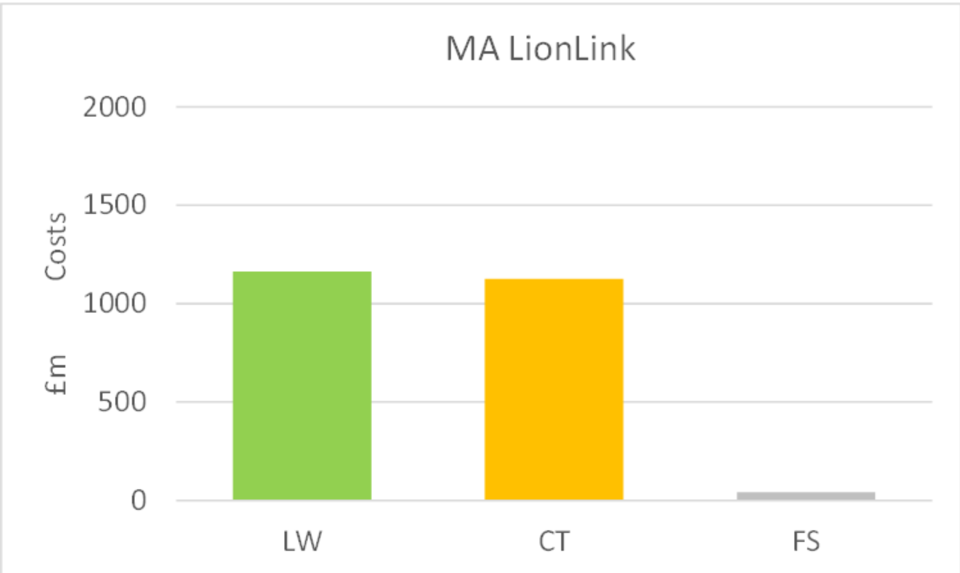

Figure 59: PV additional constraint costs due to LionLink for the Marginal Additional case, Present Value 25-year, real 2022, £m.

The above figure shows the additional constraint costs with the inclusion of LionLink for the MA case. Additional constraint costs are significantly lower than in the FA case. This is because the inclusion of the other OHA and Window 3 projects within the supply demand mix reduces the impact any one interconnector has on constraint costs. In the Leading the Way (LW) scenario constraint costs are increased by nearly £1.2bn, in Consumer Transformation (CT) by £1.1bn and in the Falling Short (FS) scenario by only £0.04bn.

Annual constraint costs

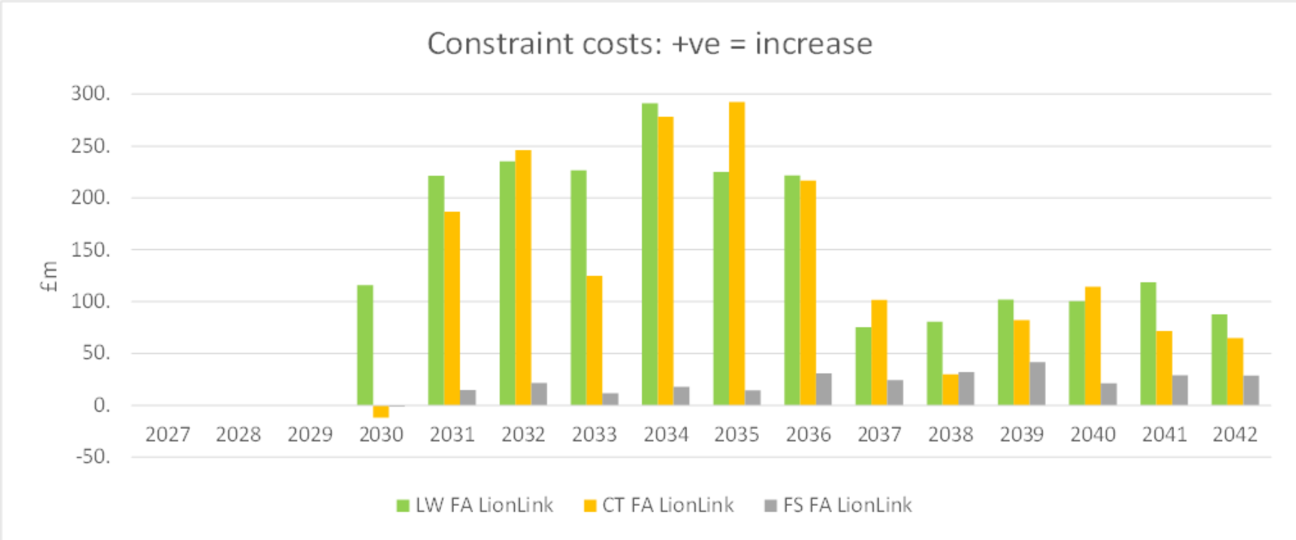

Figure 60: Additional annual constraint costs due to LionLink for the First Additional case.

The above figure shows that for the First Additional case, LionLink results in an increase in constraint costs of approximately £150m to £250m (undiscounted) in CT and LW in the years 2031 to 2036. In FS constraint cost increases are much lower, below £50m (undiscounted) in all years.

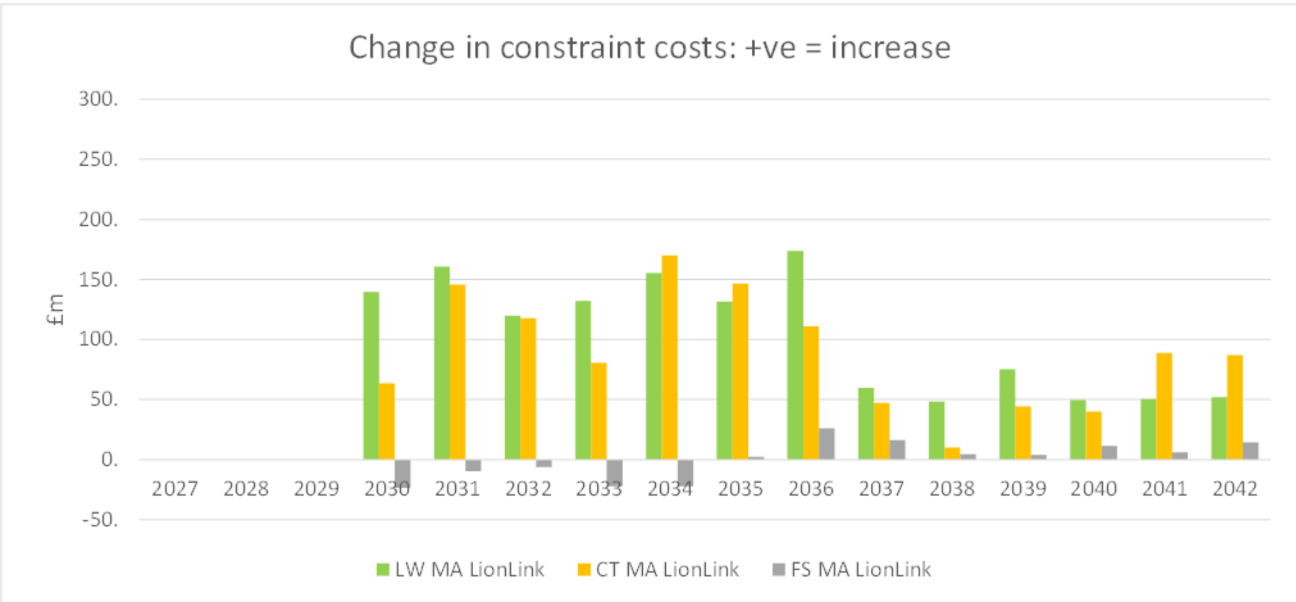

Figure 61: Additional annual constraint costs due to LionLink for the Marginal Additional case.

In the Marginal Additional case, LionLink results in increased constraint costs of between £50m and £150m (undiscounted) between 2030 and 2036 in LW and CT. Constraints are much lower in FS, with savings in the years 2030 to 2034.

Annual import and export flows for dispatch and redispatch

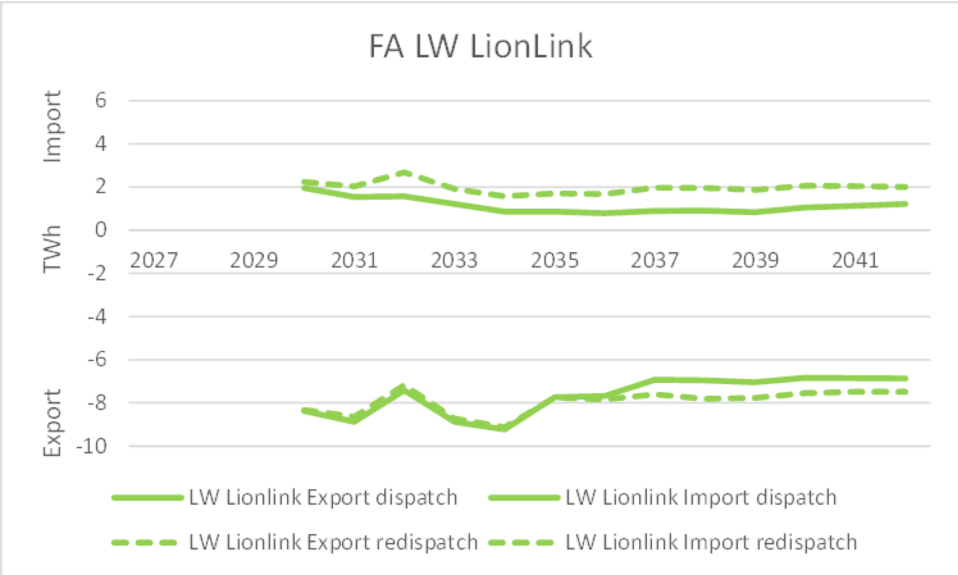

Figure 62: Annual import and export flows for LionLink in the FA case for Leading the Way.

The above figure shows LionLink has high exports and low imports in the dispatch for Leading the Way for the First Additional case. The redispatch shows a slight increase in exports in the later years and an increase in imports across the forecast.

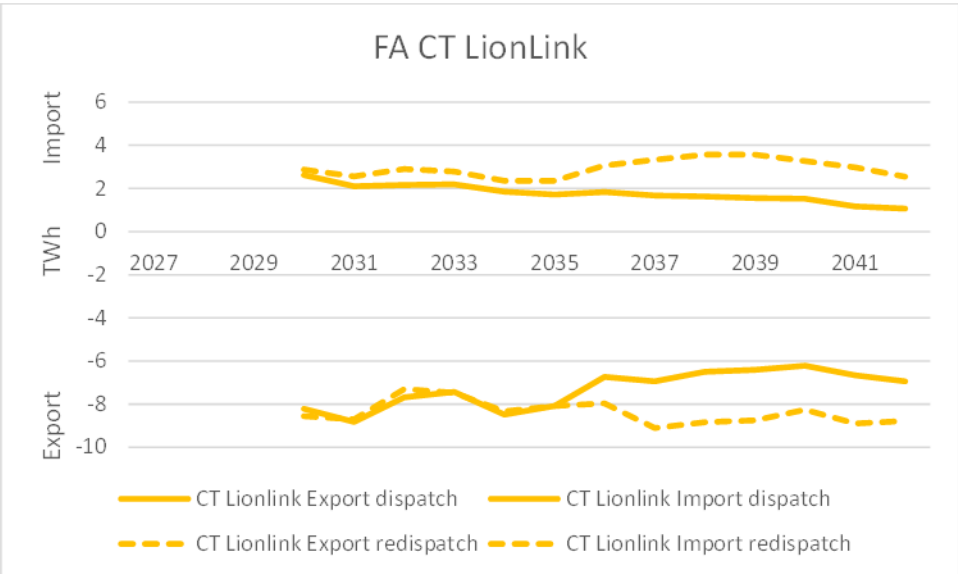

Figure 63: Annual import and export flows for LionLink in the FA case for Consumer Transformation.

The above figure shows LionLink has high exports that reduce in the later years and low imports in the dispatch for Leading the Way for the First Additional case. The redispatch shows a significant increase in exports and imports after 2035.

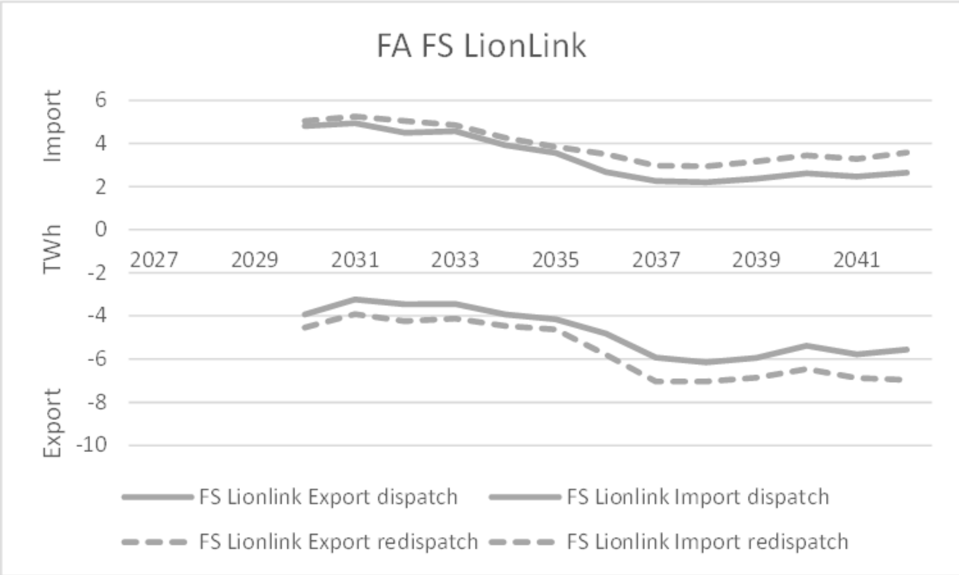

Figure 64: Annual import and export flows for LionLink in the FA case for Falling Short.

The above figure shows LionLink has similar levels of exports and imports for the early years in the dispatch for Falling Short for the First Additional case. Over time imports decrease and exports increase. The redispatch shows an increase in exports and in imports.

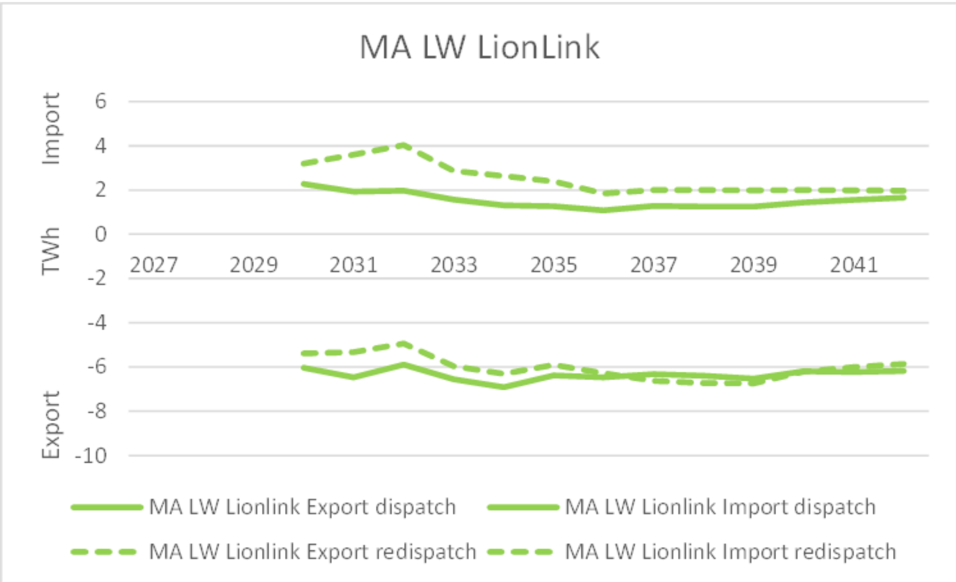

Figure 65: Annual import and export flows for LionLink in the MA case for Leading the Way.

The above figure shows LionLink has high exports, but lower than in the FA case, and low imports in the dispatch, similar to those shown in the FA case for Leading the Way. The redispatch shows a reduction in exports in the early years and an increase in imports, especially in the early years.

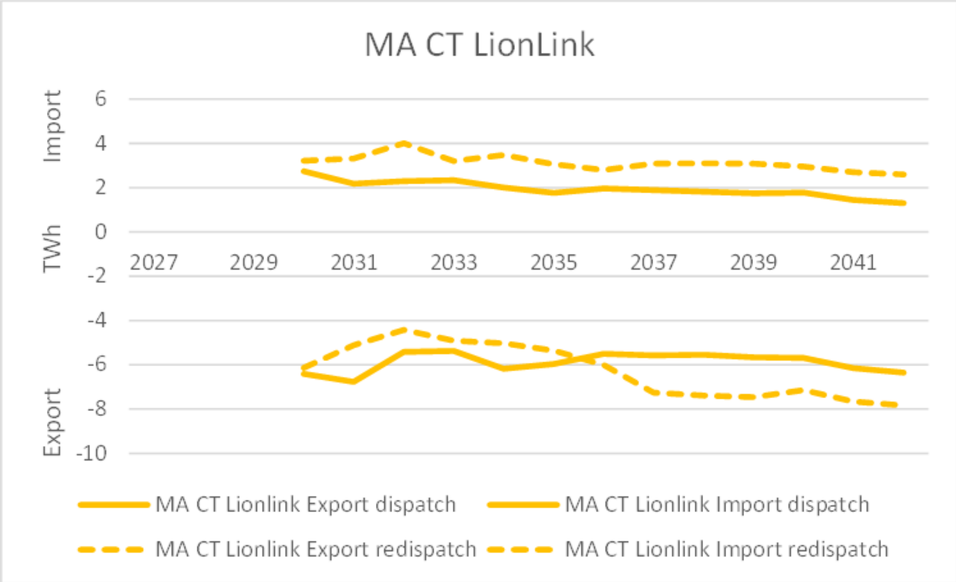

Figure 66: Annual import and export flows for LionLink in the MA case for Consumer Transformation.

The above figure shows LionLink has high exports for the MA case, but lower than in the FA case, and low imports in the dispatch, similar to those shown in the FA case for Consumer Transformation. The redispatch shows a reduction in exports in the early years followed by an increase in the later years and an increase in imports across the whole forecast period.

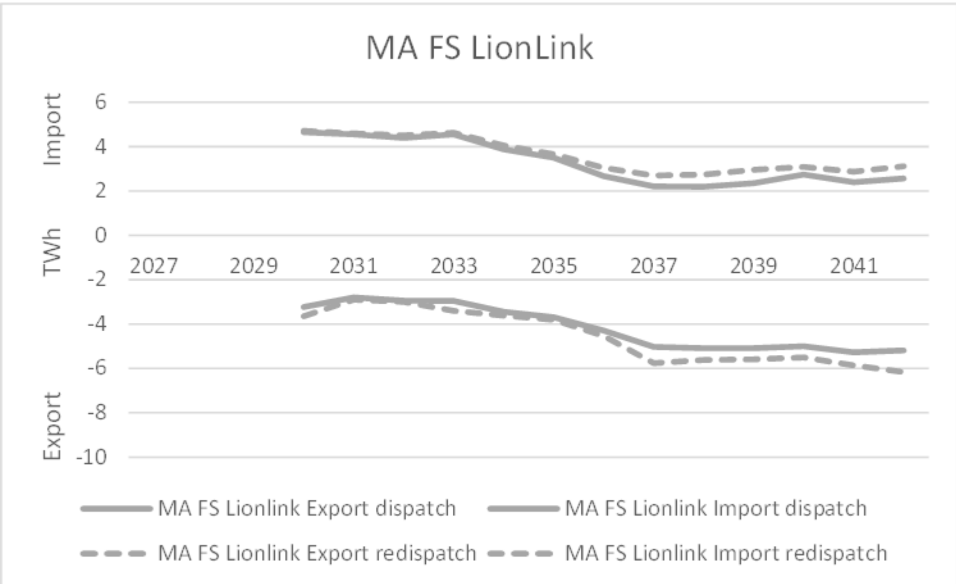

Figure 67: Annual import and export flows for LionLink in the MA case for Falling Short.

The above figure shows LionLink has similar levels of exports and imports for the early years in the dispatch for Falling Short for the Marginal Additional case. Over time imports decrease and exports increase. The redispatch shows small increases in exports and in imports in the later years.

Change in constraint costs by boundary

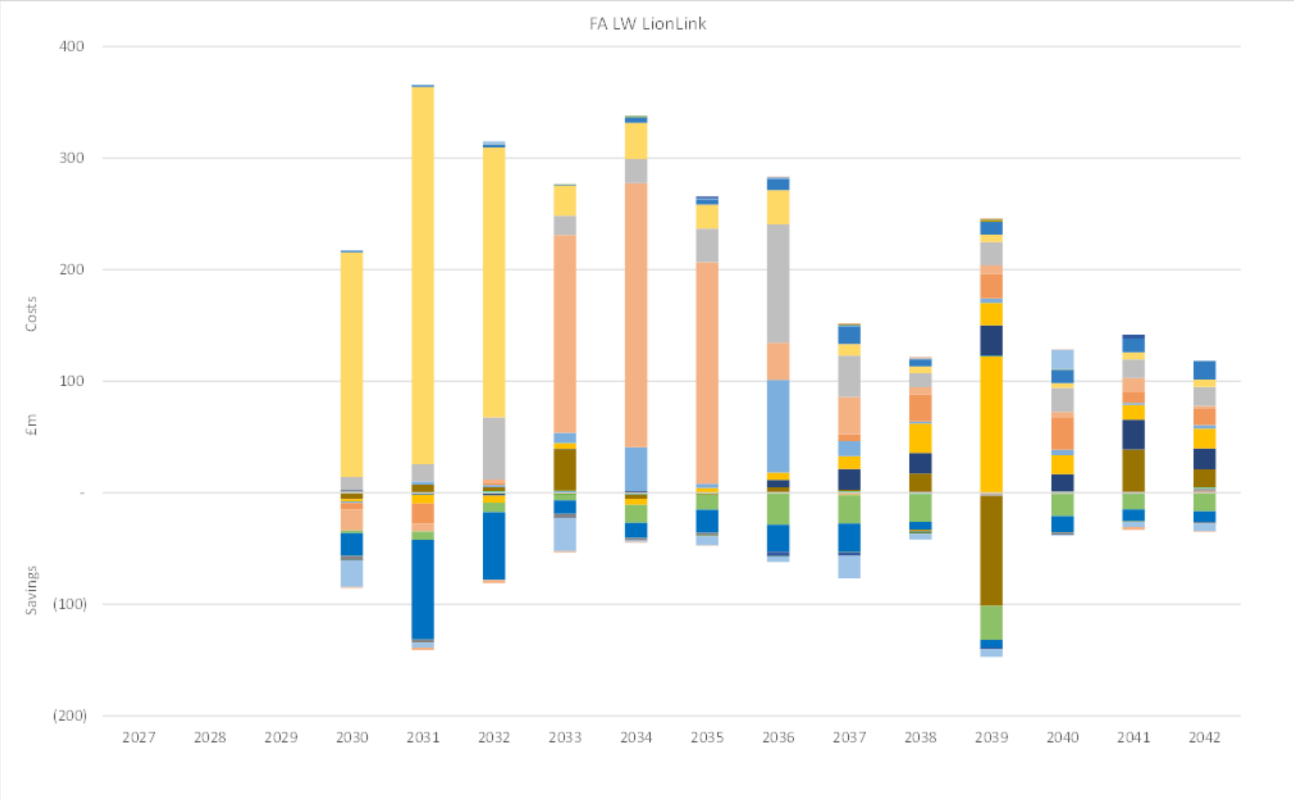

Figure 68: Change in constraint costs by boundary for LionLink for the FA case for Leading the Way.

The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for LionLink for the First Additional case for the Leading the Way scenario. Each different colour represents the change in constraint costs for a particular boundary. It is important to note that the chart shows changes in constraint costs by boundary, i.e. the difference between constraint costs when the project is included and when the project is excluded.

The figure shows that LionLink increases constraint costs on certain boundaries but also reduces constraint costs on others. Whether the impact is an increase in constraint costs or a reduction in constraint costs for a particular boundary, changes from year to year. The size of change in constraint costs by boundary can also vary significantly from year to year. This is shown clearly in the years 2038 to 2040. The figure also shows that the specific boundaries that have the greatest impact on the total change in constraint costs can vary from year to year. These factors are a result of the changes in demand, supply and network capability over time.

In general, LionLink increases constraint costs on several northern and midland boundaries, but also relieves congestion on various boundaries. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

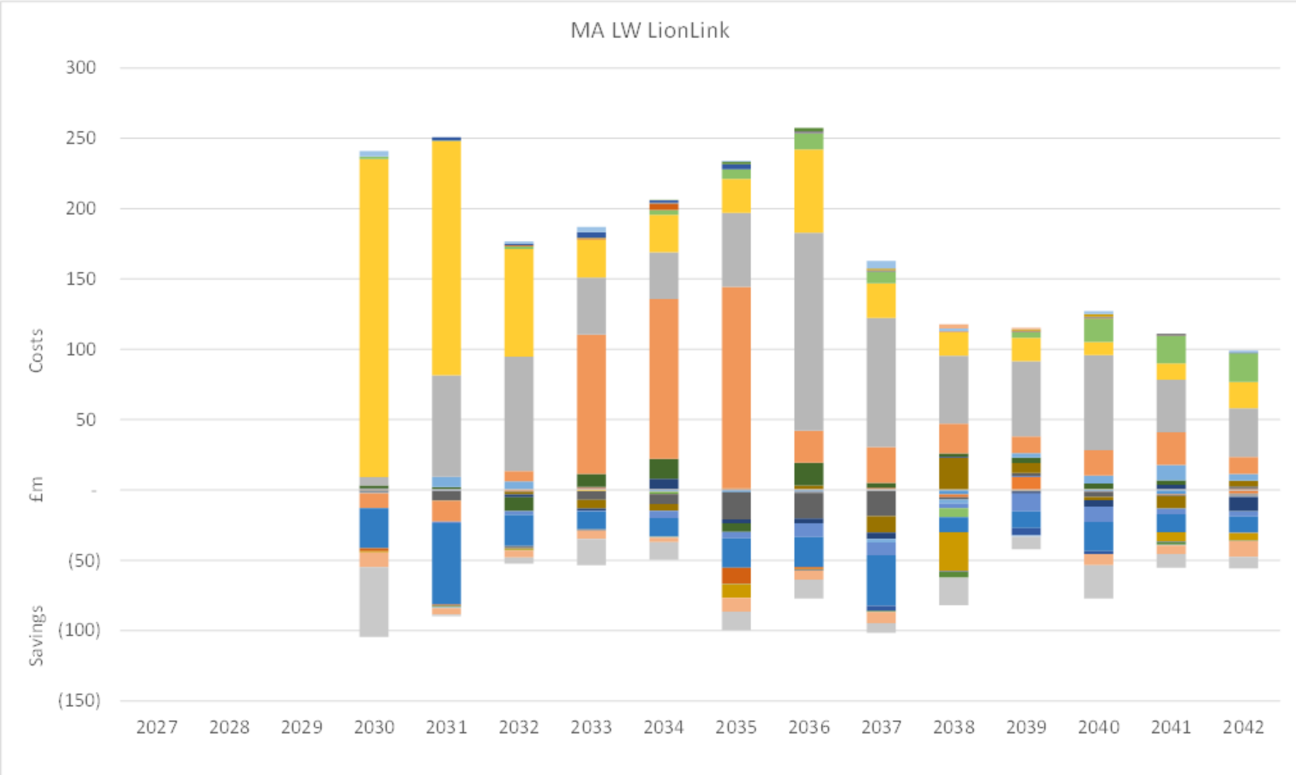

Figure 69: Change in constraint costs by boundary for LionLink for the MA case for Leading the Way.

The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for LionLink for the Marginal Additional case for the Leading the Way scenario. Each different colour represents the change in constraint costs for a particular boundary. It is important to note that the chart shows changes in constraint costs by boundary, i.e. the difference between constraint costs when the project is included and when the project is excluded.

Compared to the First Additional case, the Marginal Additional shows an overall reduction in additional constraint costs each year. This is because the Marginal Additional case has all of the W3 interconnector and OHA pilot projects included in the supply/demand background, enabling the model to minimise total constraint costs by taking balancing actions across the whole GB network for a wider range of solutions.

In general, for the Marginal Additional case, LionLink increases constraint costs on several northern and midland boundaries but relieves congestion on various boundaries. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

PV system operation

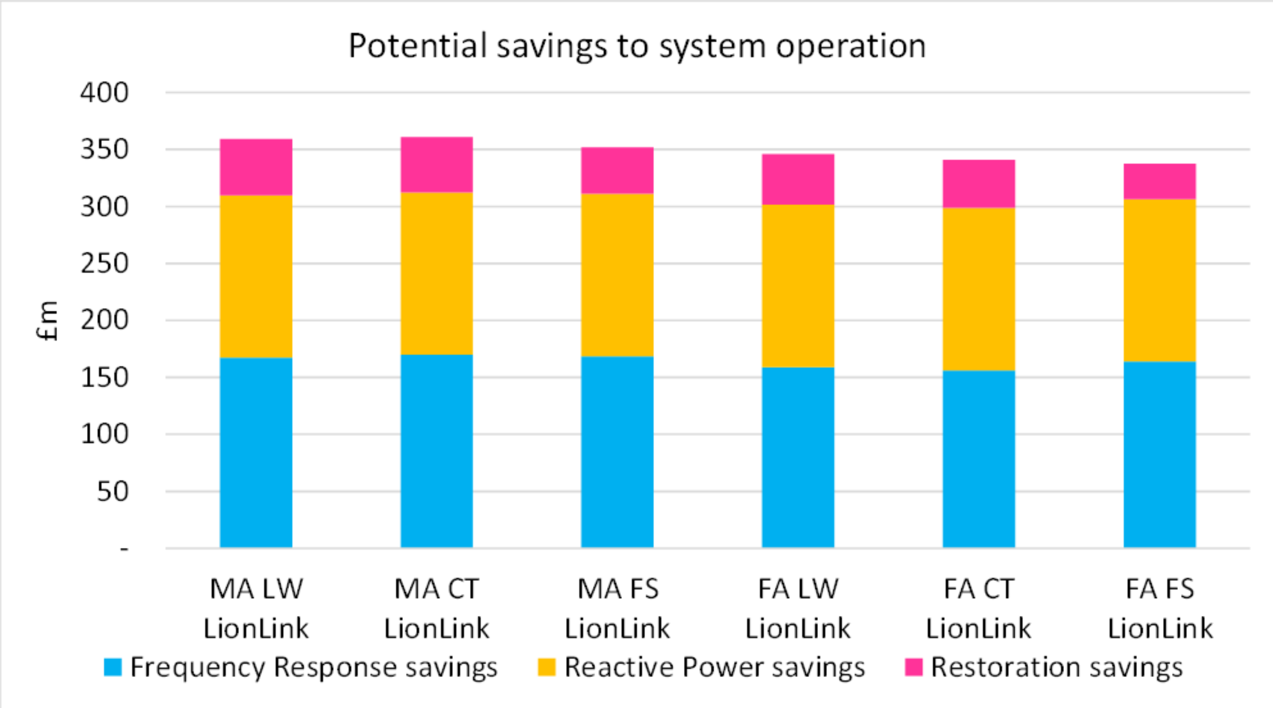

Figure 70: PV potential system operability savings for LionLink, Present Value 25-year, real 2022, £m.

The above figure shows the potential savings for frequency response, reactive power and restoration services in present value (25 year, 2022 £m) for LionLink for Leading the Way, Consumer Transformation and Falling Short for both the Marginal Additional and First Additional cases. There is considerable uncertainty around forecasting potential system operability benefits over a 25-year time horizon, but the figure shows that there is potentially significant savings in frequency response, reactive power and restoration services.

There is little variation across the three scenarios and also across the First Additional and Marginal Additional cases. This is because the potential system operability savings from the services provided by LionLink are less sensitive to flows across the OHA, whereas the constraint cost impact is highly dependent on the scale and direction of flows across the project.

RES curtailment avoided

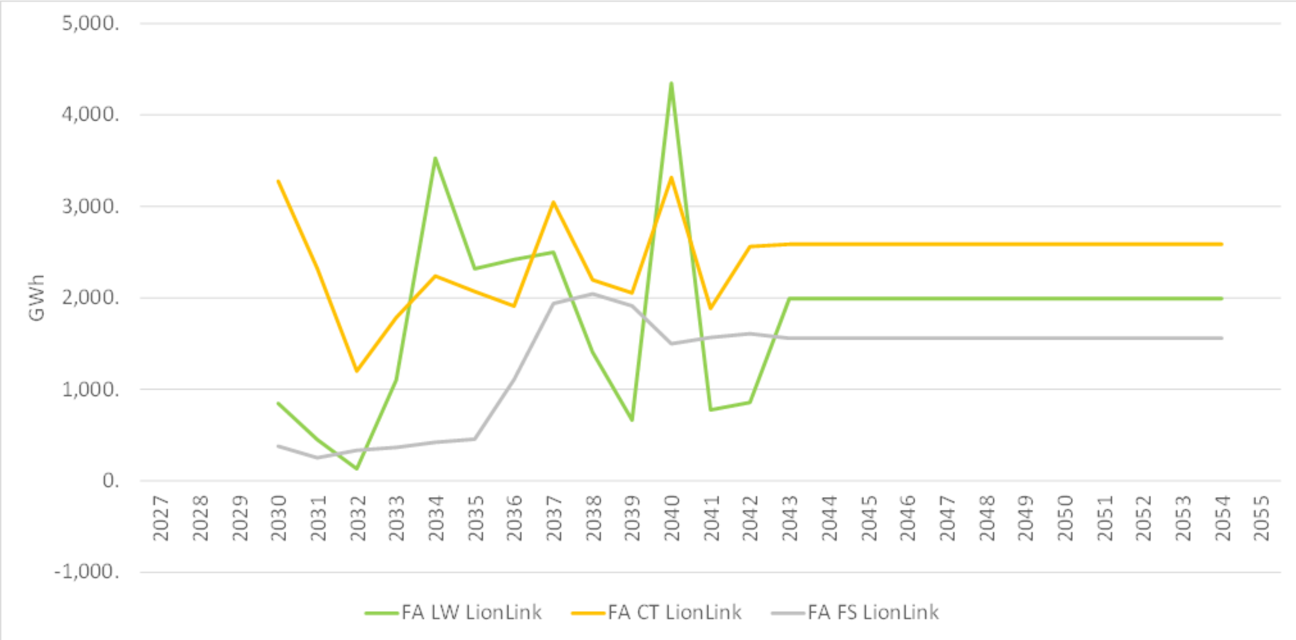

Figure 71: Annual RES curtailment avoided for LionLink for the First Additional case.

The above figure shows the renewable energy supply (RES) curtailment avoided on an annual basis for Leading the Way, Consumer Transformation and Falling Short for the First Additional case. Note that beyond 2042, the results are an average of the years 2040, 2041 and 2042, as our detailed modelling with FES22 only extends out to 2042. The figure shows that the level of annual RES curtailment avoided when LionLink is included is approximately between 0.5TWh and 3TWh, which equates to approximately between 1.4GWh and 8.2GWh per day.

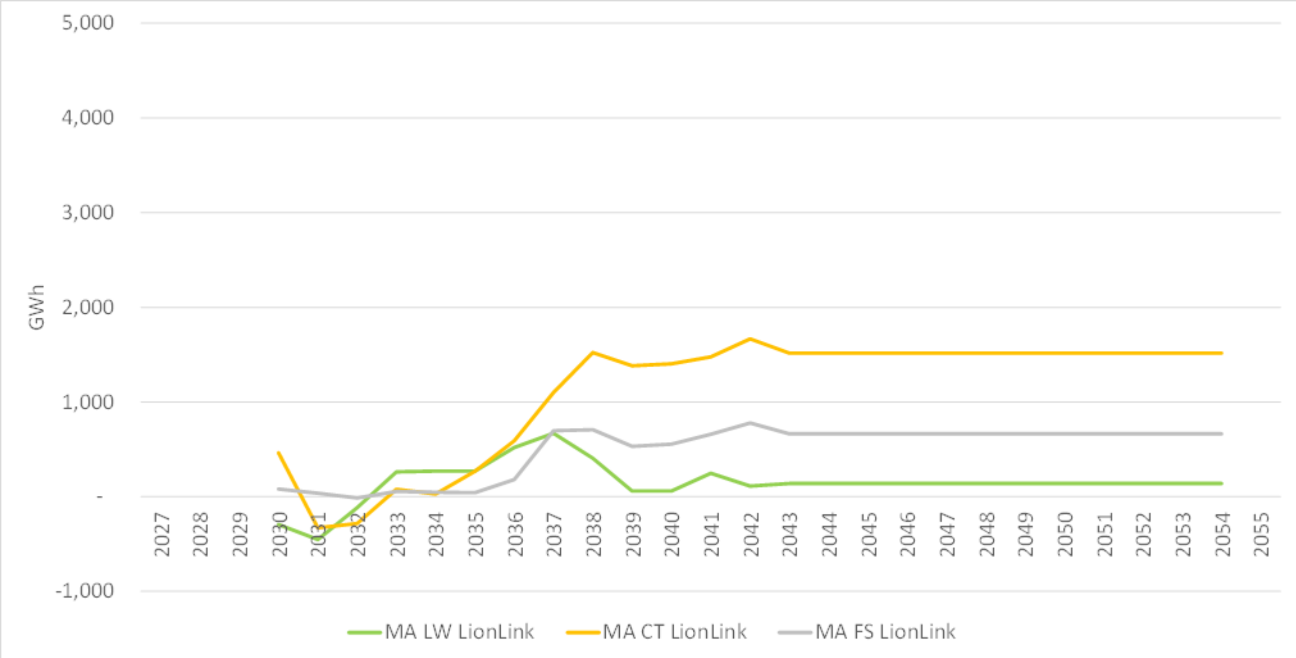

Figure 72: Annual RES curtailment avoided for LionLink for the Marginal Additional case.

The above figure shows the renewable energy supply (RES) curtailment avoided on an annual basis for Leading the Way, Consumer Transformation and Falling Short for the Marginal Additional case. Note that beyond 2042, the results are an average of the years 2040, 2041 and 2042, as our detailed modelling with FES22 only extends out to 2042. The figure shows that the level of annual RES curtailment avoided when LionLink is included is approximately between 0.1TWh and 1.5TWh, which equates to approximately between 0.3GWh and 4.1GWh per day.

14. LirIC

LirIC is a W3 interconnector project. It has a capacity of 700MW and connects to Northern Ireland.

PV constraint costs

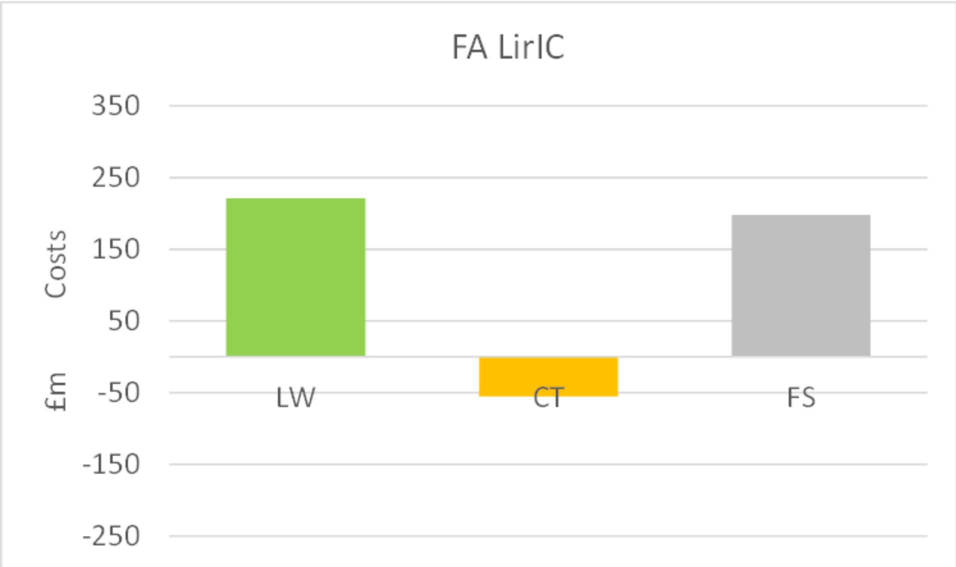

Figure 73: PV additional constraint costs due to LirIC for the First Additional case, Present Value 25-year, real 2022, £m.

The above figure shows LirIC results in a £200m to £220m increase in constraint costs in Falling Short and Leading the Way in the First Additional case, and a £55m decrease in constraint costs in Consumer Transformation.

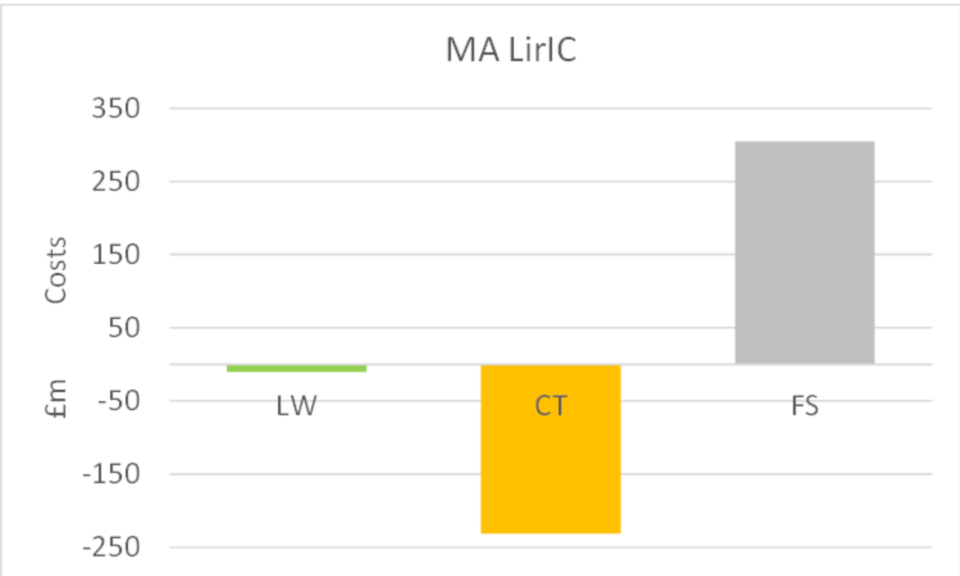

Figure 74: PV additional constraint costs due to LirIC for the Marginal Additional case, Present Value 25-year, real 2022, £m.

The above figure shows the additional constraint costs with the inclusion of LirIC for the Marginal Additional case. For LW and CT in the MA case, LirIC results in savings of £23m and £230m respectively. However, in the Falling Short scenario, additional constraint costs are higher compared to the First Additional case, at £300m.

Annual constraint costs

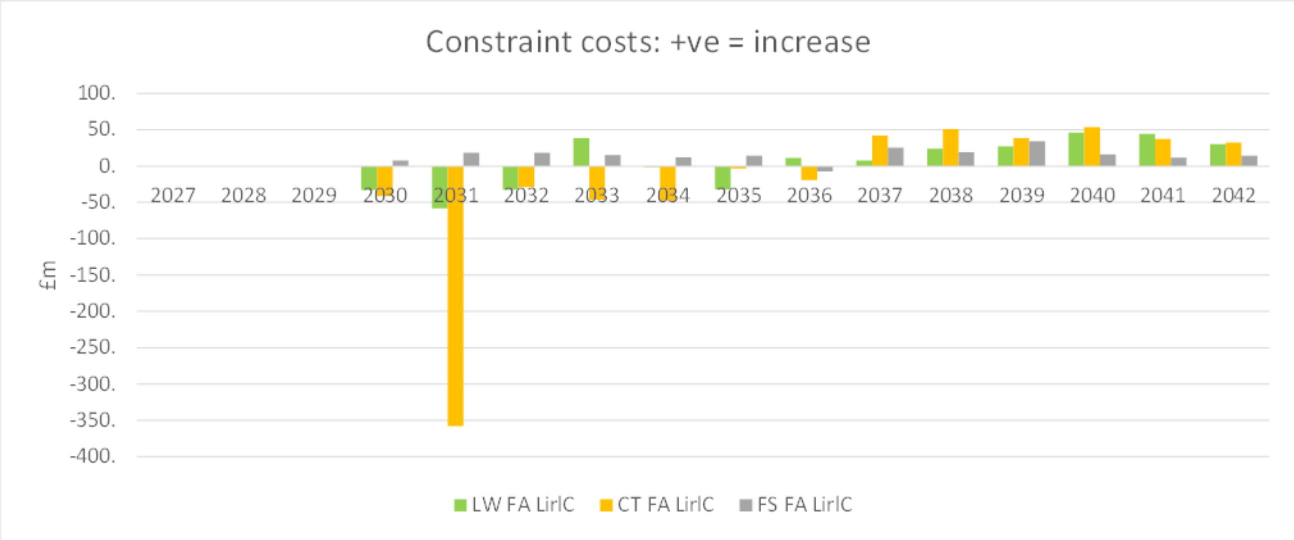

Figure 75: Additional annual constraint costs due to LirIC for the First Additional case.

The above figure shows that for the First Additional case, LirIC results in decreased constraint costs (undiscounted) of approximately £50m in the early 2030s in CT and LW, except 2031 where a decrease of approximately £350m is observed in CT. The high levels of constraint cost reduction in 2031 in CT is because the inclusion of LirIC enables the model to produce a solution that decreases constraints across potentially one or more boundaries. The unique combination of electricity supply, demand and boundary capabilities seen in 2031 for CT is not replicated in any other years, suggesting that for later years either supply or demand patterns or boundary capabilities have changed. This is explored in subsequent charts in this section. In FS, LirIC results in a small increase in constraint costs in most years of less than £50m.

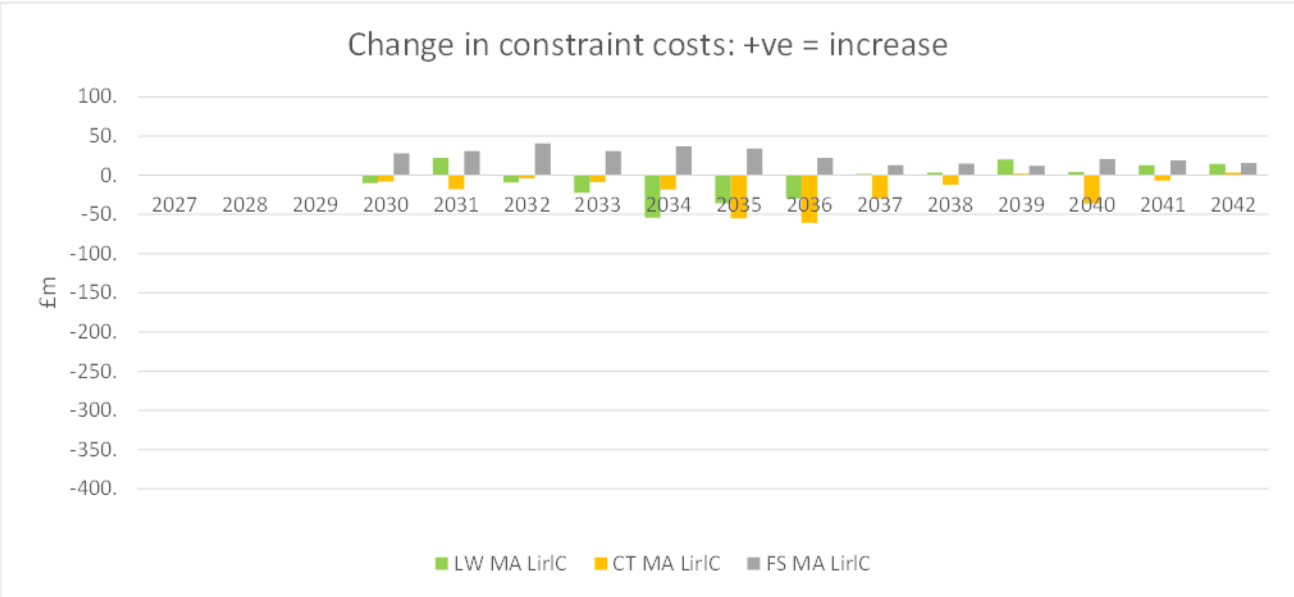

Figure 76: Additional annual constraint costs due to LirIC for the Marginal Additional case.

The above figure shows that in the Marginal Additional case, LirIC results in decreased constraint costs of up to approximately £50m (undiscounted) in the years 2034 to 2036 in LW and CT. FS results in increased constraint costs of less than £50m per year (undiscounted). The figure shows that there is no repeat of the £350m constraint saving in 2031, as seen in the First Additional case. This is because in the MA case, which has all of the other W3 and OHA pilot projects included, the addition of LirIC is not providing the model such significant constraint saving opportunities.

Annual import and export flows for dispatch and redispatch

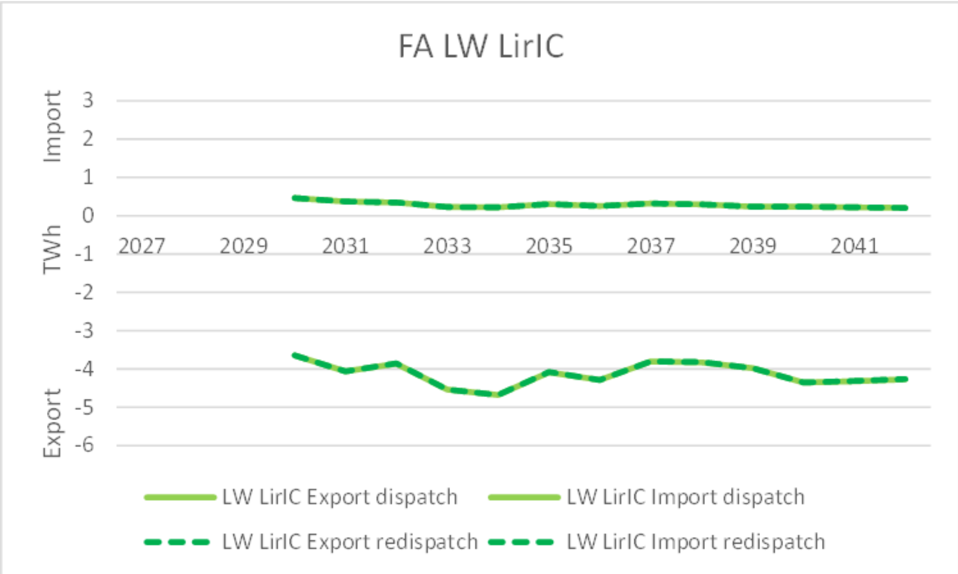

Figure 77: Annual import and export flows for LirIC in the FA case for Leading the Way.

The above figure shows LirIC has high exports and very low imports in the dispatch for Leading the Way for the First Additional case. The redispatch shows the same levels of exports and imports as the dispatch. This is because the BID3 model is configured to model as accurately as possible the actual operation of the transmission system.

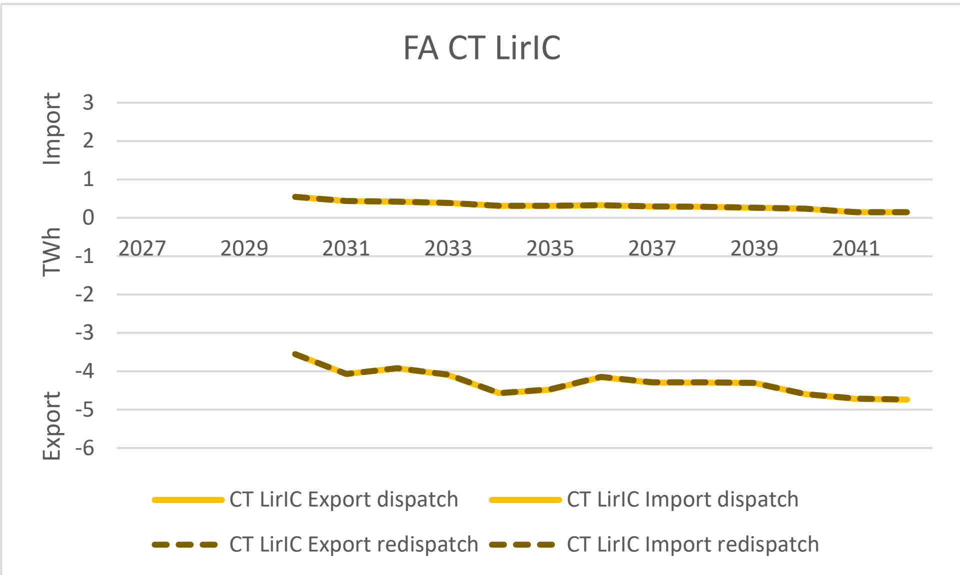

Figure 78: Annual import and export flows for LirIC in the FA case for Consumer Transformation.

The above figure shows LirIC has high exports and very low imports in the dispatch for Consumer Transformation for the First Additional case. The redispatch shows the same levels of exports and imports as the dispatch. This is because the BID3 model is configured to model as accurately as possible the actual operation of the transmission system.

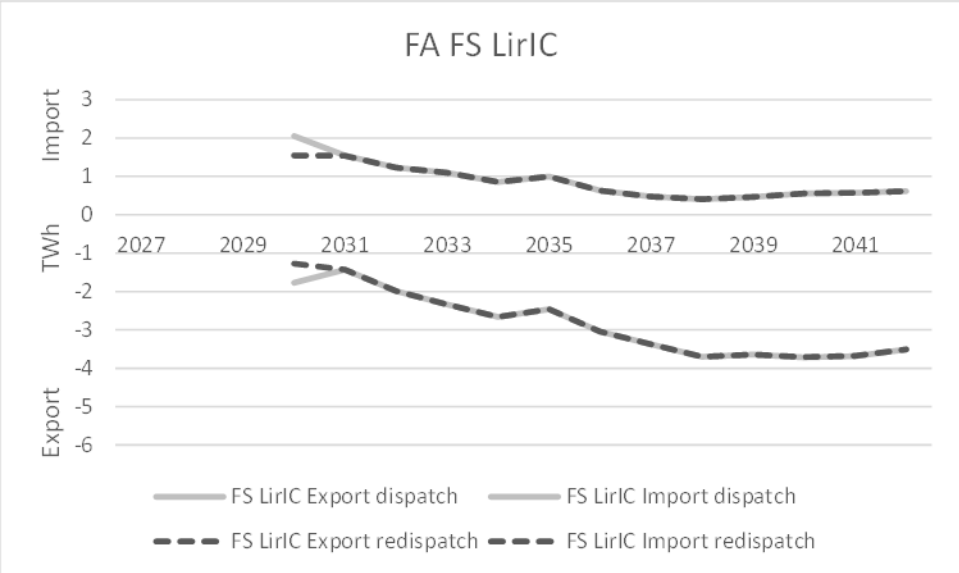

Figure 79: Annual import and export flows for LirIC in the FA case for Falling Short.

The above figure shows LirIC has increasing levels of exports over the forecast period up to 2038 and decreasing imports up to 2038 in the dispatch for Falling Short for the First Additional case.

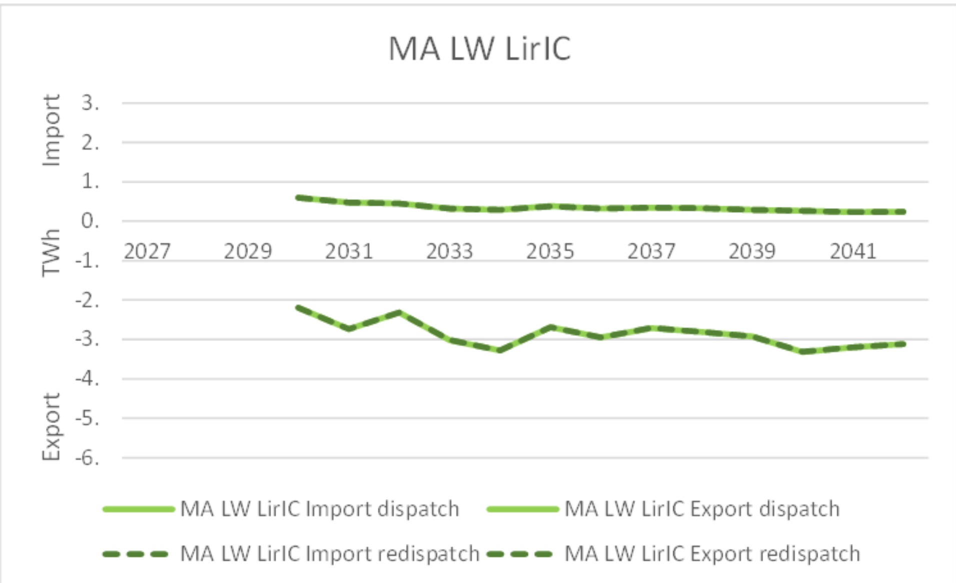

Figure 80: Annual import and export flows for LirIC in the MA case for Leading the Way.

The above figure shows that for the Marginal Additional case, LirIC has high exports, but lower than in the FA case, and low imports in the dispatch, similar to those shown in the FA case for Leading the Way. The redispatch shows the same levels of exports and imports as the dispatch. This is because the BID3 model is configured to model as accurately as possible the actual operation of the transmission system.

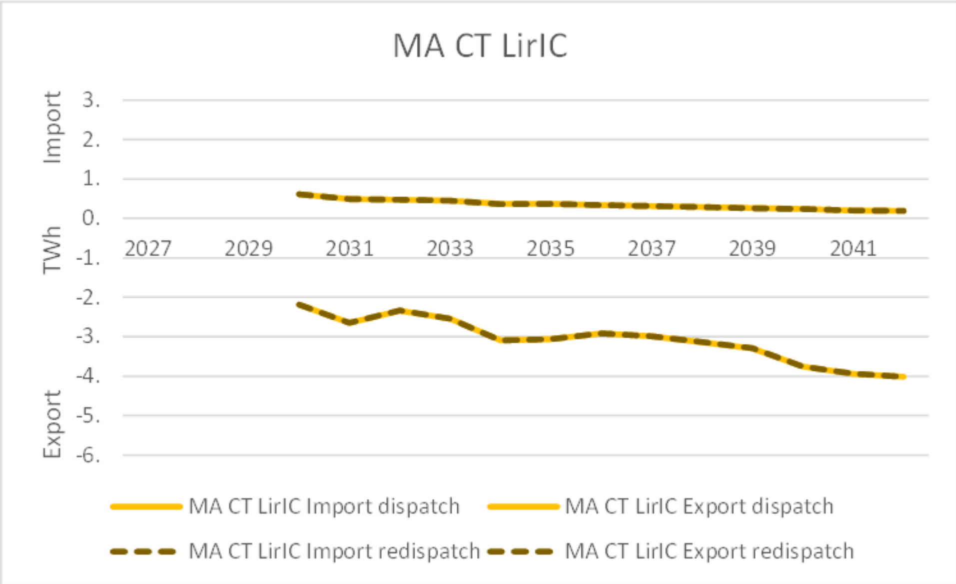

Figure 81: Annual import and export flows for LirIC in the MA case for Consumer Transformation.

The above figure shows that for the Marginal additional case, LirIC has high exports, but lower than in the FA case and very low imports in the dispatch for Consumer Transformation. The redispatch shows the same levels of exports and imports as the dispatch. This is because the BID3 model is configured to model as accurately as possible the actual operation of the transmission system.

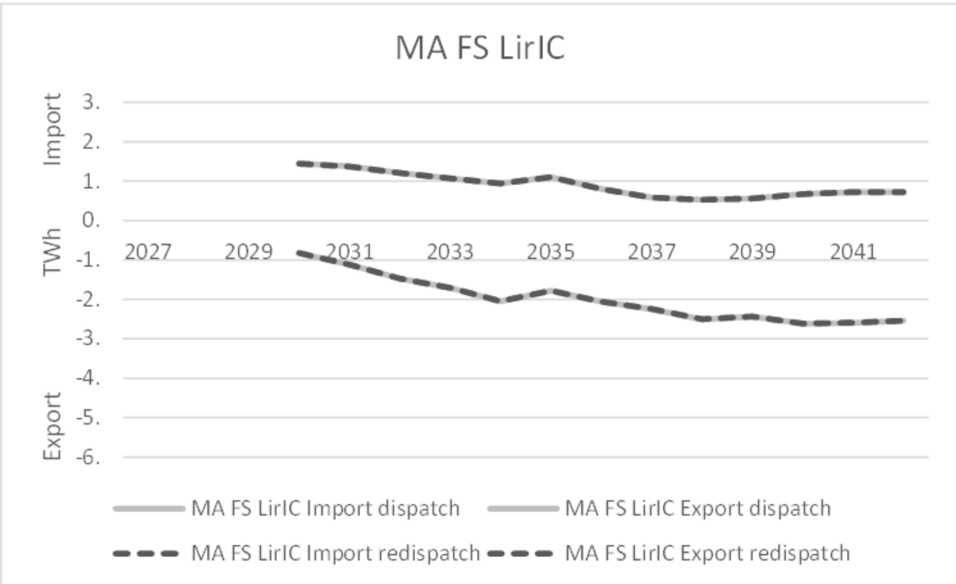

Figure 82: Annual import and export flows for LirIC in the MA case for Falling Short.

The above figure shows that for the Marginal Additional case LirIC has increasing levels of exports over the forecast period up to 2040 and decreasing imports in the dispatch for Falling Short.

Change in constraint costs by boundary

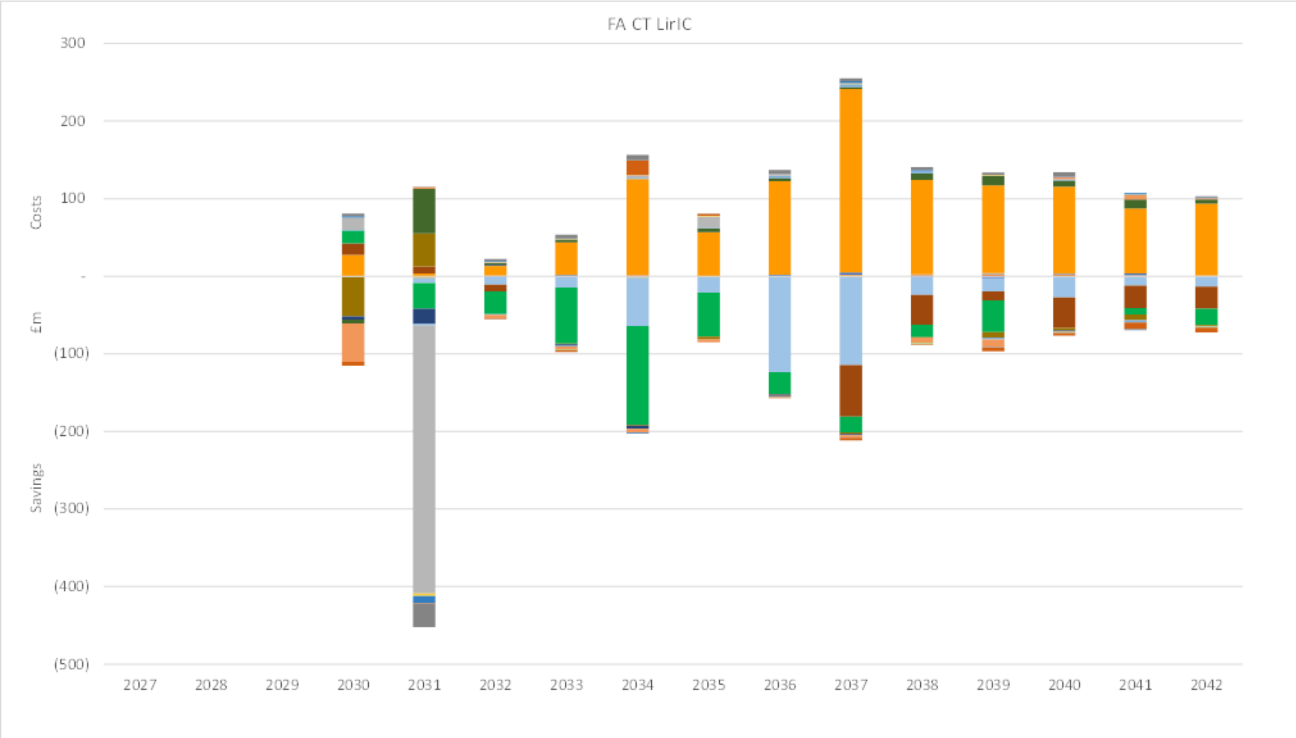

Figure 83: Change in constraint costs by boundary for LirIC for the FA case for Consumer Transformation.

The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for LirIC for the First Additional case for the Consumer Transformation scenario. Each different colour represents the change in constraint costs for a particular boundary. It is important to note that the chart shows changes in constraint costs by boundary, i.e. the difference between constraint costs when the project is included and when the project is excluded.

The figure shows that LirIC increases constraint costs on certain boundaries but also reduces constraint costs on others. Whether the impact is an increase in constraint costs or a reduction in constraint costs for a particular boundary, changes from year to year. The size of change in constraint costs by boundary can also vary significantly from year to year. This is shown clearly in the year 2031. The figure also shows that the specific boundaries that have the greatest impact on the total change in constraint costs can vary from year to year. These factors are a result of the changes in demand, supply and network capability over time.

The figure shows that the large constraint saving previously highlighted in Figure 75 for the year 2031 is driven by savings across a single boundary, in this case a Welsh boundary. The saving only occurs for a single year suggesting the combination of supply, demand and boundary capabilities that enable such a significant saving across one boundary when LirIC is included only exist for 2031. That is in later years, supply and demand patterns and boundary capabilities will have evolved such that the model is no longer able to produce the lowest total cost solution by significantly reducing constraint costs across that particular boundary when LirIC is included.

In general, LirIC increases constraint costs on a particular Scottish boundary, but relieves congestion on other Scottish, northern and midland boundaries, and of course the Welsh boundary in 2031. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

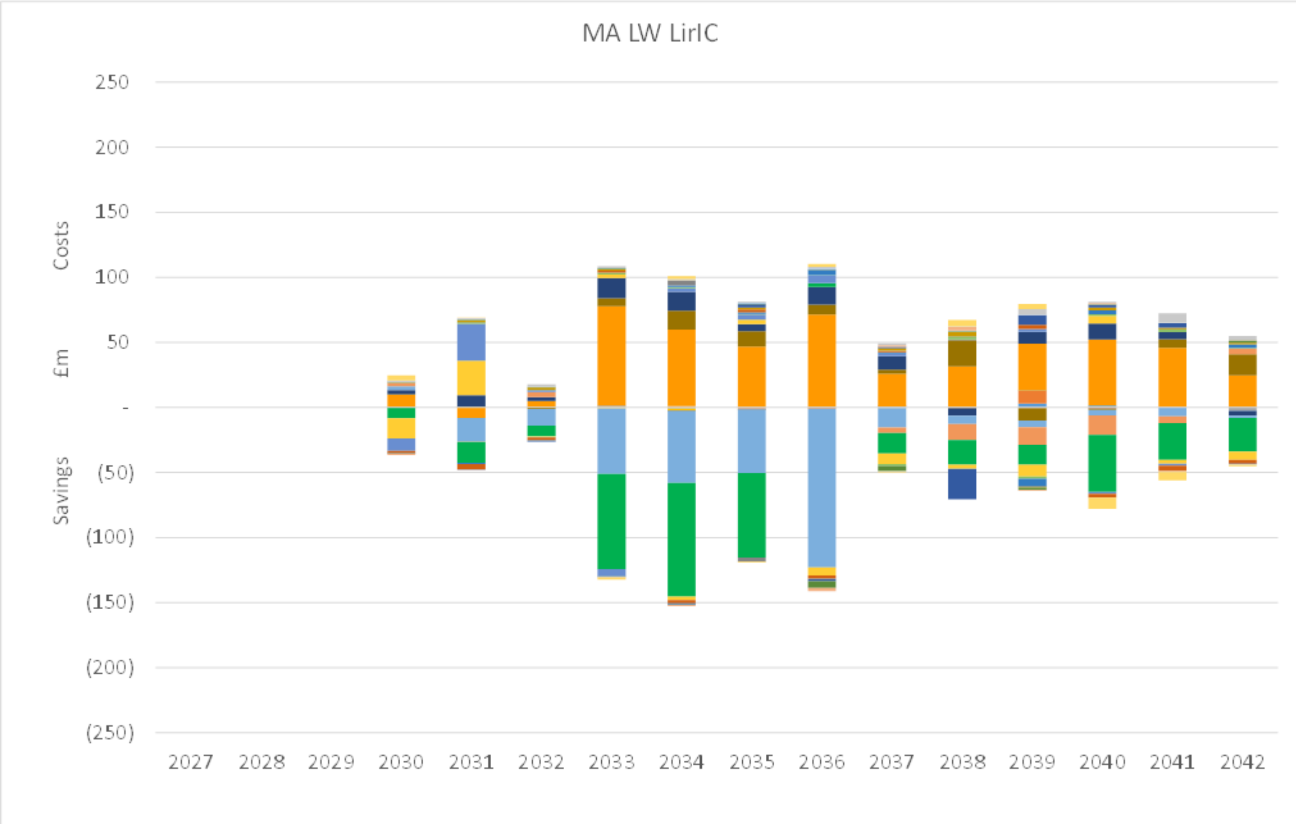

Figure 84: Change in constraint costs by boundary for LirIC for the MA case for Leading the Way.

The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for LirIC for the Marginal Additional case for the Leading the Way scenario. Each different colour represents the change in constraint costs for a particular boundary. It is important to note that the chart shows changes in constraint costs by boundary, i.e. the difference between constraint costs when the project is included and when the project is excluded.

Compared to the First Additional case, the Marginal Additional case shows an overall reduction in additional constraint costs each year, and a slight reduction in constraint savings for each year. This is because the Marginal Additional case has all of the W3 interconnector and OHA pilot projects included in the supply/demand background, enabling the model to minimise total constraint costs by taking balancing actions across the whole GB for a wider range of solutions.

In general, for the Marginal Additional case, LirIC increases constraint costs on a Scottish boundary in particular but relieves congestion on other Scottish and northern boundaries. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

PV system operation

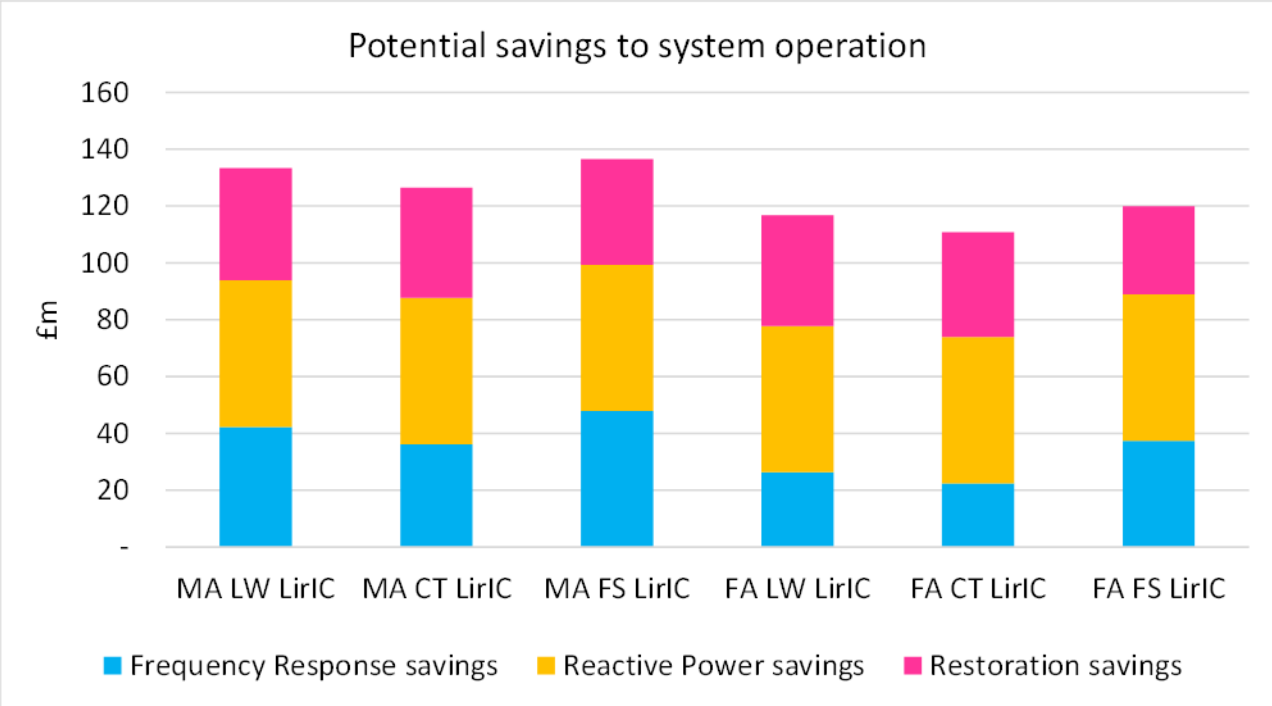

Figure 85: PV potential system operability savings for LirIC, Present Value 25-year, real 2022, £m.

The above figure shows the potential savings for frequency response, reactive power and restoration services in present value (25 year, 2022 £m) for LirIC for Leading the Way, Consumer Transformation and Falling Short for both the Marginal Additional and First Additional cases. There is considerable uncertainty around forecasting potential system operability benefits over a 25-year time horizon, but the figure shows that there is potentially significant savings in frequency response, reactive power and restoration services.

There is little variation across the three scenarios and also across the First Additional and Marginal Additional cases. This is because the potential system operability savings from the services provided by LirIC are less sensitive to flows across the interconnector, whereas the constraint cost impact is highly dependent on the scale and direction of flows across the project.

RES curtailment avoided

Figure 86: Annual RES curtailment avoided for LirIC for the First Additional case.

The above figure shows the renewable energy supply (RES) curtailment avoided on an annual basis for Leading the Way, Consumer Transformation and Falling Short for the First Additional case. Note that beyond 2042, the results are an average of the years 2040, 2041 and 2042, as our detailed modelling with FES22 only extends out to 2042. The figure shows a spike in RES curtailment avoided in Consumer Transformation for 2031: this coincides with the large constraint saving seen across one boundary for that year. The figure shows that the level of annual RES curtailment avoided when LirIC is included is approximately between 1TWh and 2TWh, which equates to approximately between 2.7GWh and 5.5GWh per day. Up to 2036 in the Falling Short scenario, LirIC results in a small increase in RES curtailment.

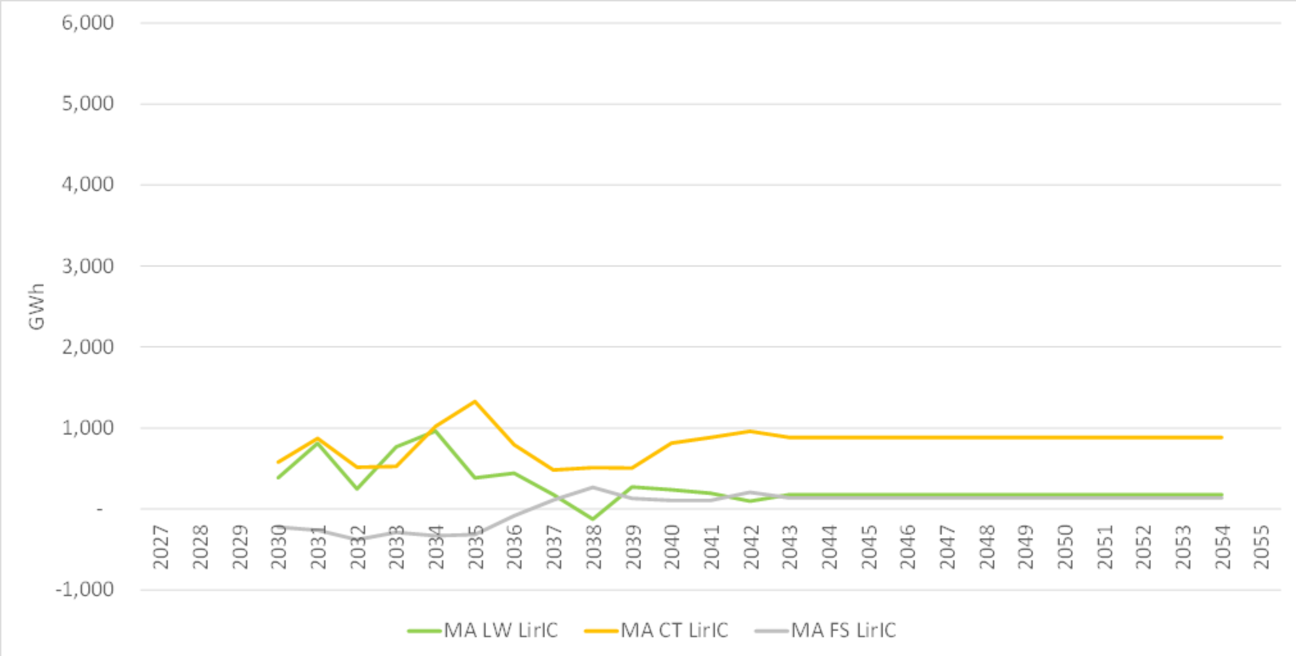

Figure 87: Annual RES curtailment avoided for LirIC for the Marginal Additional case.

The above figure shows the renewable energy supply (RES) curtailment avoided on an annual basis for Leading the Way, Consumer Transformation and Falling Short for the Marginal Additional case. Note that beyond 2042, the results are an average of the years 2040, 2041 and 2042, as our detailed modelling with FES22 only extends out to 2042. The figure shows that the level of annual RES curtailment avoided when LirIC is included is approximately between 0.2TWh and 1TWh, which equates to approximately between 0.5GWh and 2.7GWh per day. Up to 2036 in the Falling Short scenario, LirIC results in a small increase in RES curtailment.

15. MaresConnect

MaresConnect is a W3 interconnector project. It has a capacity of 0.75GW and connects to Ireland.

PV constraint costs

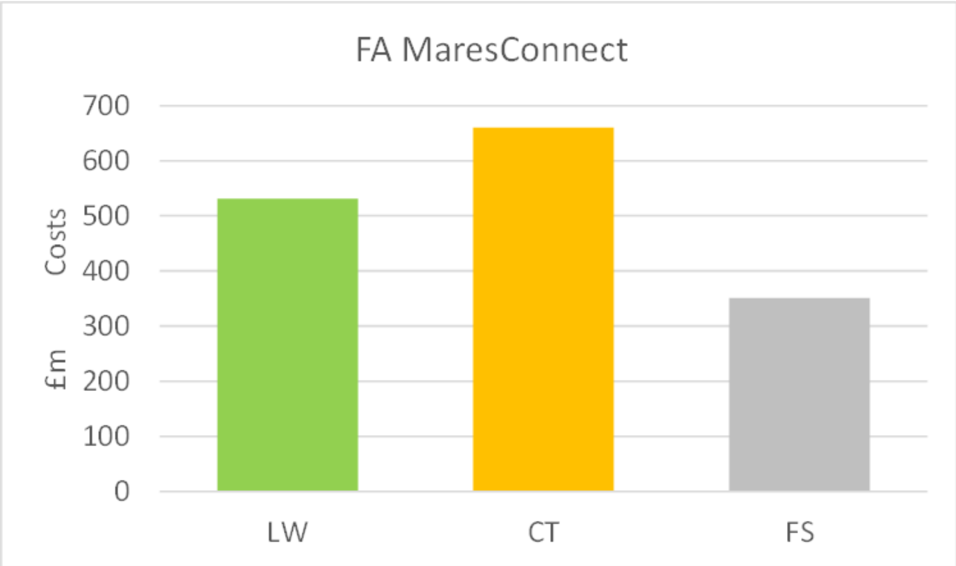

Figure 88: PV additional constraint costs due to MaresConnect for the First Additional case, Present Value 25-year, real 2022, £m.

The above figure shows the additional constraint costs with the inclusion of MaresConnect for the FA case. In the Leading the Way (LW) scenario constraint costs are increased by £0.53bn, in Consumer Transformation (CT) by £0.66bn and in the Falling Short (FS) scenario by £0.35bn.

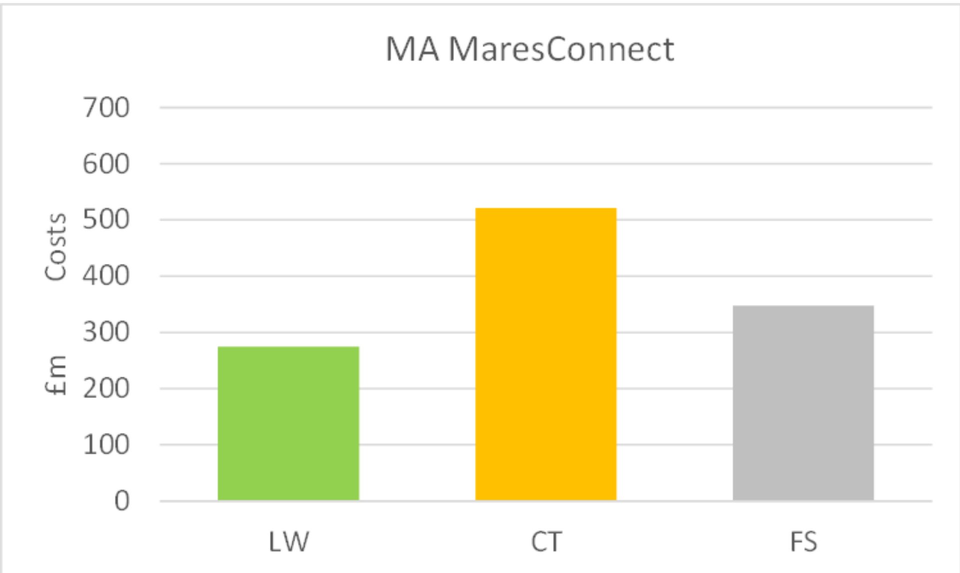

Figure 89: PV additional constraint costs due to MaresConnect for the Marginal Additional case, Present Value 25-year, real 2022, £m.

The above figure shows the additional constraint costs with the inclusion of MaresConnect for the MA case. Additional constraint costs are lower than in the FA case for the Leading the Way and Consumer Transformation scenarios. In the

Leading the Way (LW) scenario constraint costs are increased by £0.27bn and in Consumer Transformation (CT) by £0.52bn. For Falling Short for the MA case, additional constraint costs are the same as in the FA case, at £0.35bn.

Annual constraint costs

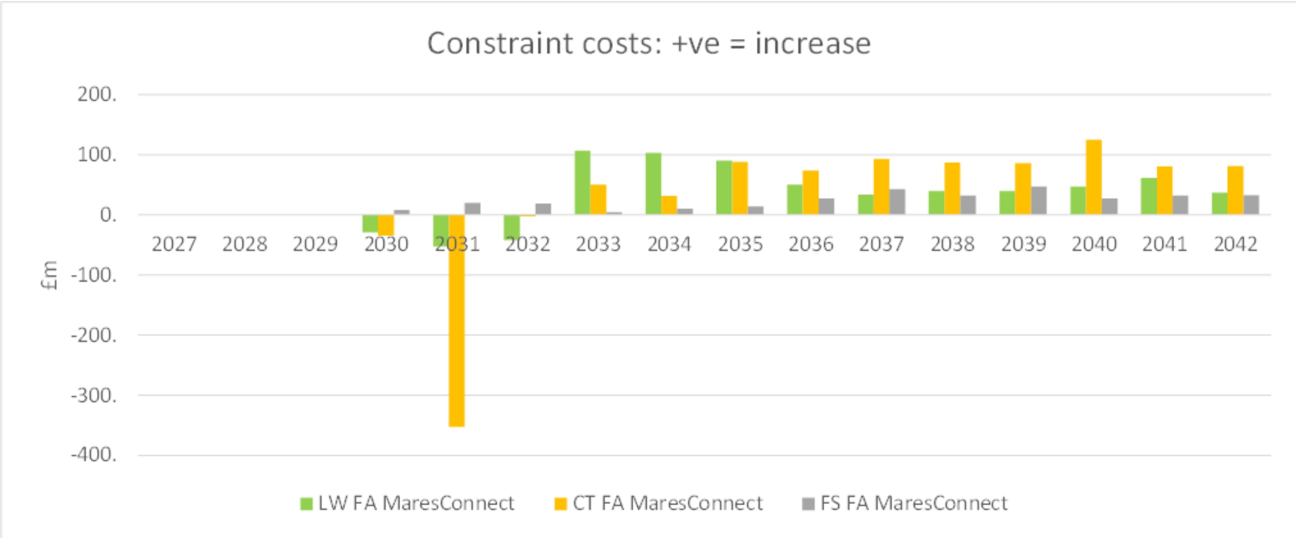

Figure 90: Additional annual constraint costs due to MaresConnect for the First Additional case.

The above figure shows that for the First Additional case, MaresConnect results in increased constraint costs (undiscounted) of between £50m and £100m for the mid to late 2030s in CT and LW, except 2031 where a decrease of approximately £350m is observed in CT. The high level of constraint cost reduction in 2031 in CT is because the inclusion of MaresConnect enables the model to produce a solution that decreases constraints across potentially one or more boundaries. The unique combination of electricity supply, demand and boundary capabilities seen in 2031 for CT is not replicated in any other years, suggesting that for later years either supply or demand patterns or boundary capabilities have changed. This is explored in subsequent charts in this section. In FS, MaresConnect results in increased constraint costs in most years of less than £50m.

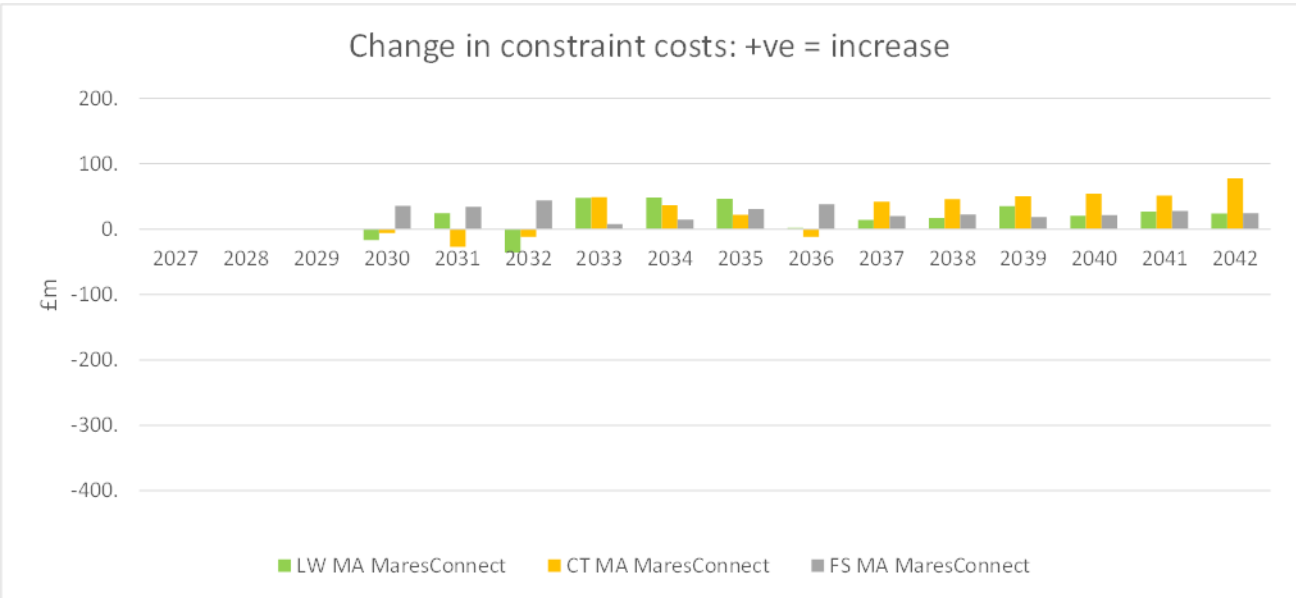

Figure 91: Additional annual constraint costs due to MaresConnect for the Marginal Additional case.

The above figure shows that in the Marginal Additional case, MaresConnect results in decreased constraint costs of up to approximately £50m (undiscounted) in the years 2030 to 2032 in LW and CT. FS results in increased constraint costs of less than £50m per year (undiscounted). The figure shows that there is no repeat of the £350m constraint saving in 2031, as seen in the First Additional case. This is because in the MA case, which has all of the other W3 and OHA pilot projects included, the addition of MaresConnect is not providing the model such significant constraint saving opportunities.

Annual import and export flows for dispatch and redispatch

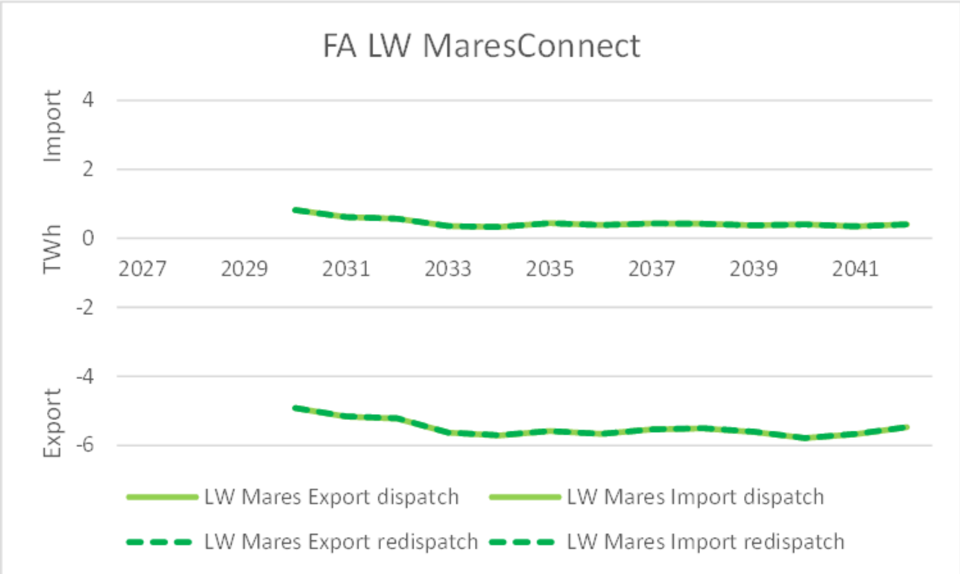

Figure 92: Annual import and export flows for MaresConnect in the FA case for Leading the Way.

The above figure shows MaresConnect has high exports and low imports in the dispatch for Leading the Way for the First Additional case. The redispatch shows the same levels of exports and imports as the dispatch. This is because the BID3 model is configured to model as accurately as possible the actual operation of the transmission system.

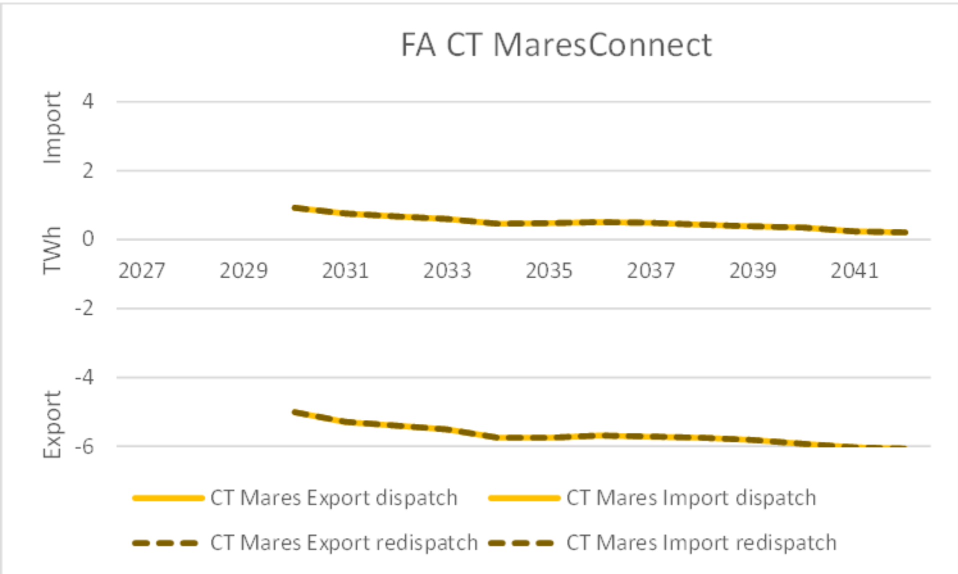

Figure 93: Annual import and export flows for MaresConnect in the FA case for Consumer Transformation.

The above figure shows MaresConnect has high exports and low imports in the dispatch for Consumer Transformation for the First Additional case. The redispatch shows the same levels of exports and imports as the dispatch. This is because the BID3 model is configured to model as accurately as possible the actual operation of the transmission system.

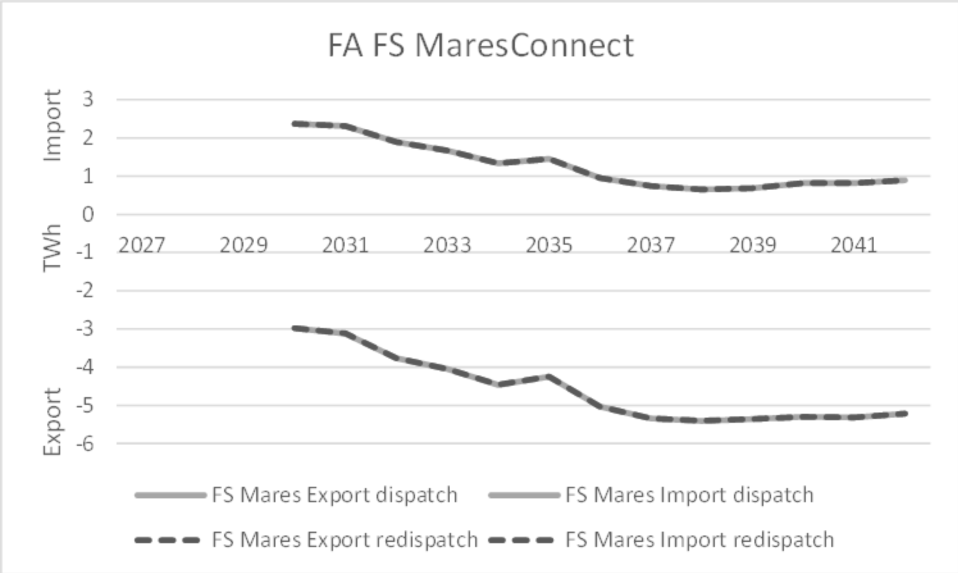

Figure 94: Annual import and export flows for MaresConnect in the FA case for Falling Short.

The above figure shows MaresConnect has increasing levels of exports over the forecast period up to 2038 and decreasing imports up to 2038 in the dispatch for Falling Short for the First Additional case.

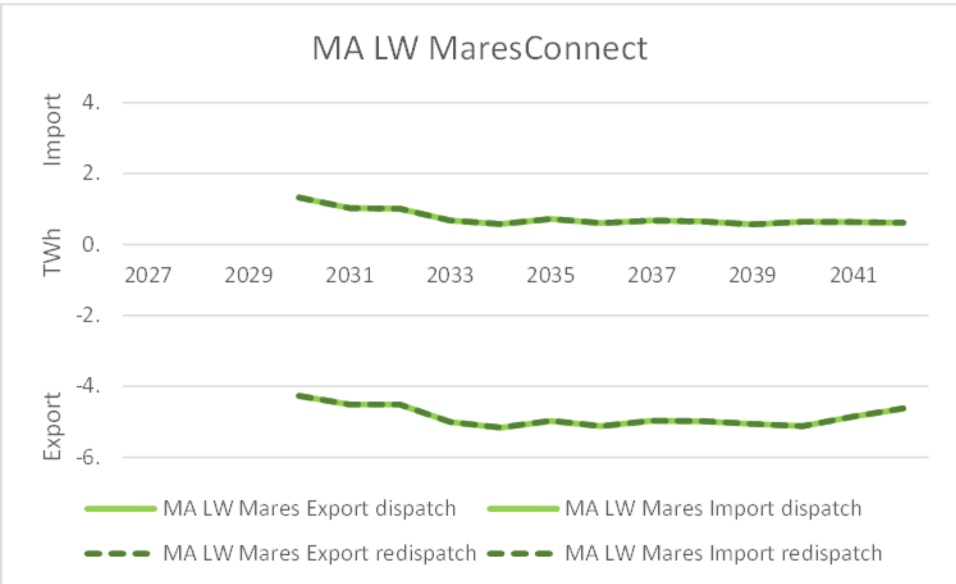

Figure 95: Annual import and export flows for MaresConnect in the MA case for Leading the Way.

The above figure shows that for the Marginal Additional case, MaresConnect has high exports, but lower than in the First Additional case, and low imports in the dispatch, similar to those shown in the FA case for Leading the Way. The redispatch shows the same levels of exports and imports as the dispatch. This is because the BID3 model is configured to model as accurately as possible the actual operation of the transmission system.

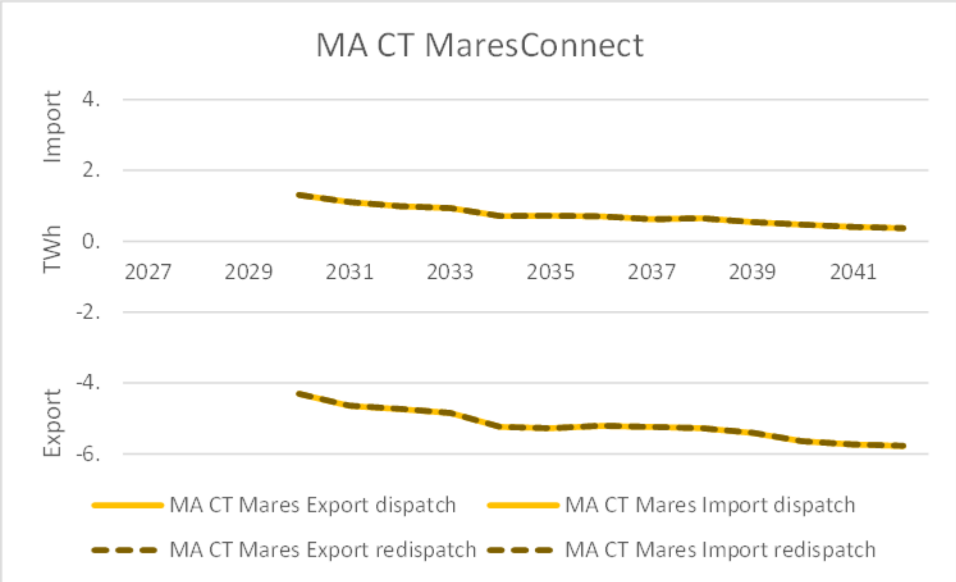

Figure 96: Annual import and export flows for MaresConnect in the MA case for Consumer Transformation.

The above figure shows that for the Marginal Additional case, MaresConnect has high exports, but lower than in the FA case and low imports in the dispatch for Consumer Transformation. The redispatch shows the same levels of exports and imports as the dispatch. This is because the BID3 model is configured to model as accurately as possible the actual operation of the transmission system.

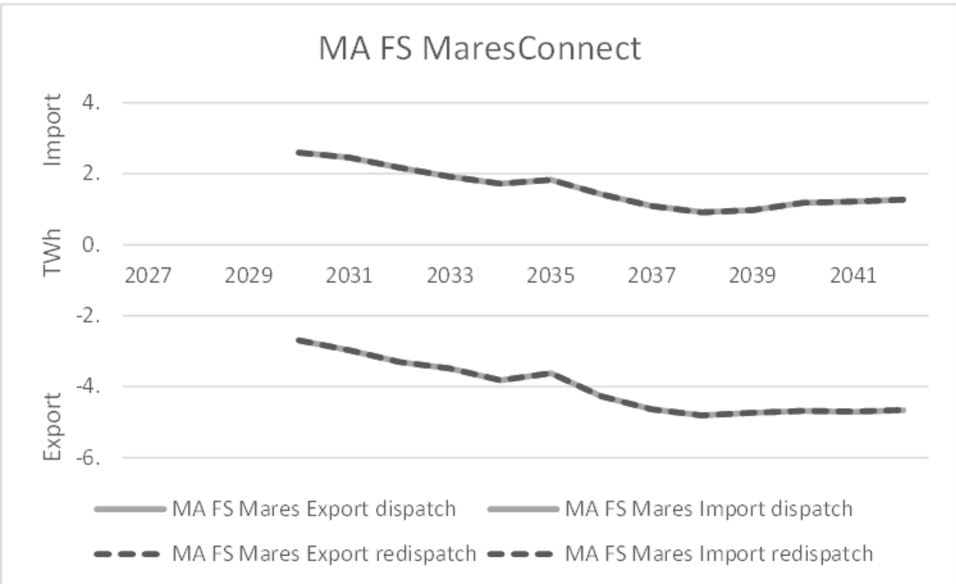

Figure 97: Annual import and export flows for MaresConnect in the MA case for Falling Short.

The above figure shows that for the Marginal Additional case MaresConnect has increasing levels of exports over the forecast period up to 2038, but lower than in the First Additional case and decreasing imports in the dispatch for Falling Short.

Change in constraint costs by boundary

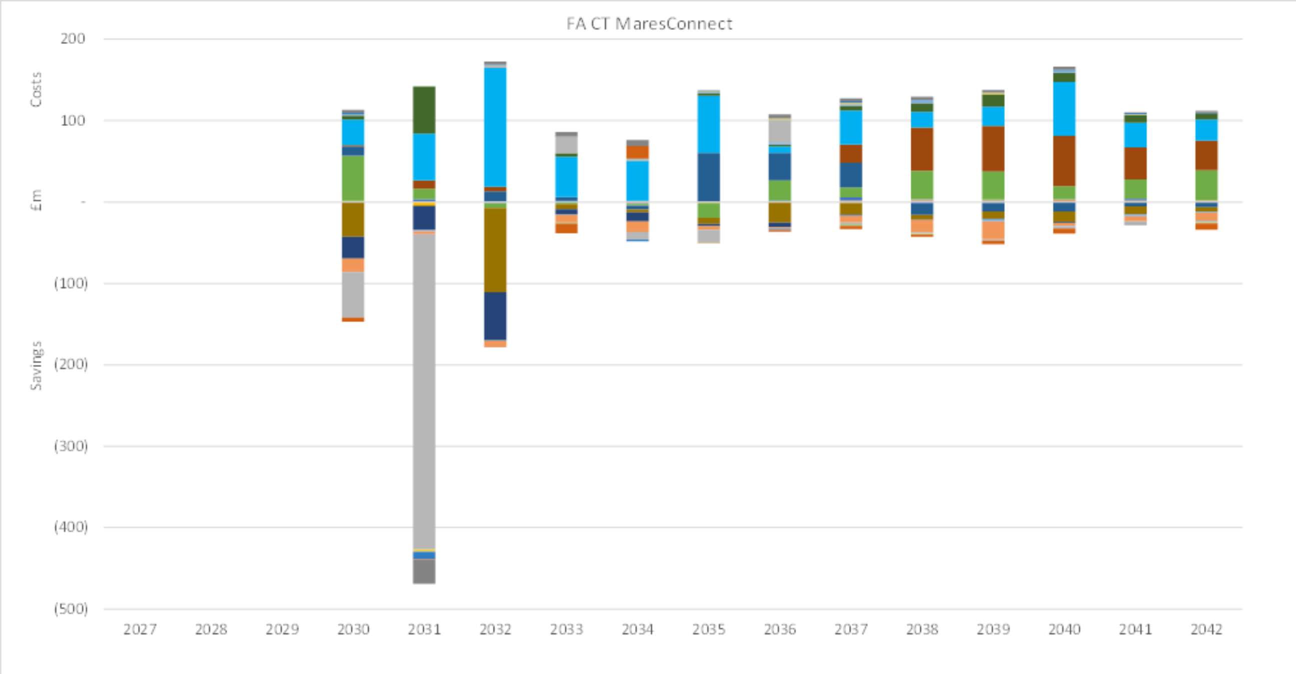

Figure 98: Change in constraint costs by boundary for MaresConnect for the FA case for Consumer Transformation.

The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for MaresConnect for the First Additional case for the Consumer Transformation scenario. Each different colour represents the change in constraint costs for a particular boundary. It is important to note that the chart shows changes in constraint costs by boundary, i.e. the difference between constraint costs when the project is included and when the project is excluded.

The figure shows that MaresConnect increases constraint costs on certain boundaries but also reduces constraint costs on others. Whether the impact is an increase in constraint costs or a reduction in constraint costs for a particular boundary, changes from year to year. The size of change in constraint costs by boundary can also vary significantly from year to year. This is shown clearly in the years 2030 to 2032. The figure also shows that the specific boundaries that have the greatest impact on the total change in constraint costs can vary from year to year. These factors are a result of the changes in demand, supply and network capability over time.

The figure shows that the large constraint saving previously highlighted in Figure 90 for the year 2031 is driven by savings across a single boundary, in this case a Welsh boundary. The very high levels of savings only occur for a single year, suggesting the combination of supply, demand and boundary capabilities that enable such a significant saving across one boundary when MaresConnect is included only exist for 2031. That is in later years, supply and demand patterns and boundary capabilities will have evolved such that the model is no longer able to produce the lowest total cost solution by significantly reducing constraint costs across that particular boundary when MaresConnect is included.

In general, MaresConnect increases constraint costs on several northern boundaries, but relieves congestion on several midland and one Welsh boundary. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

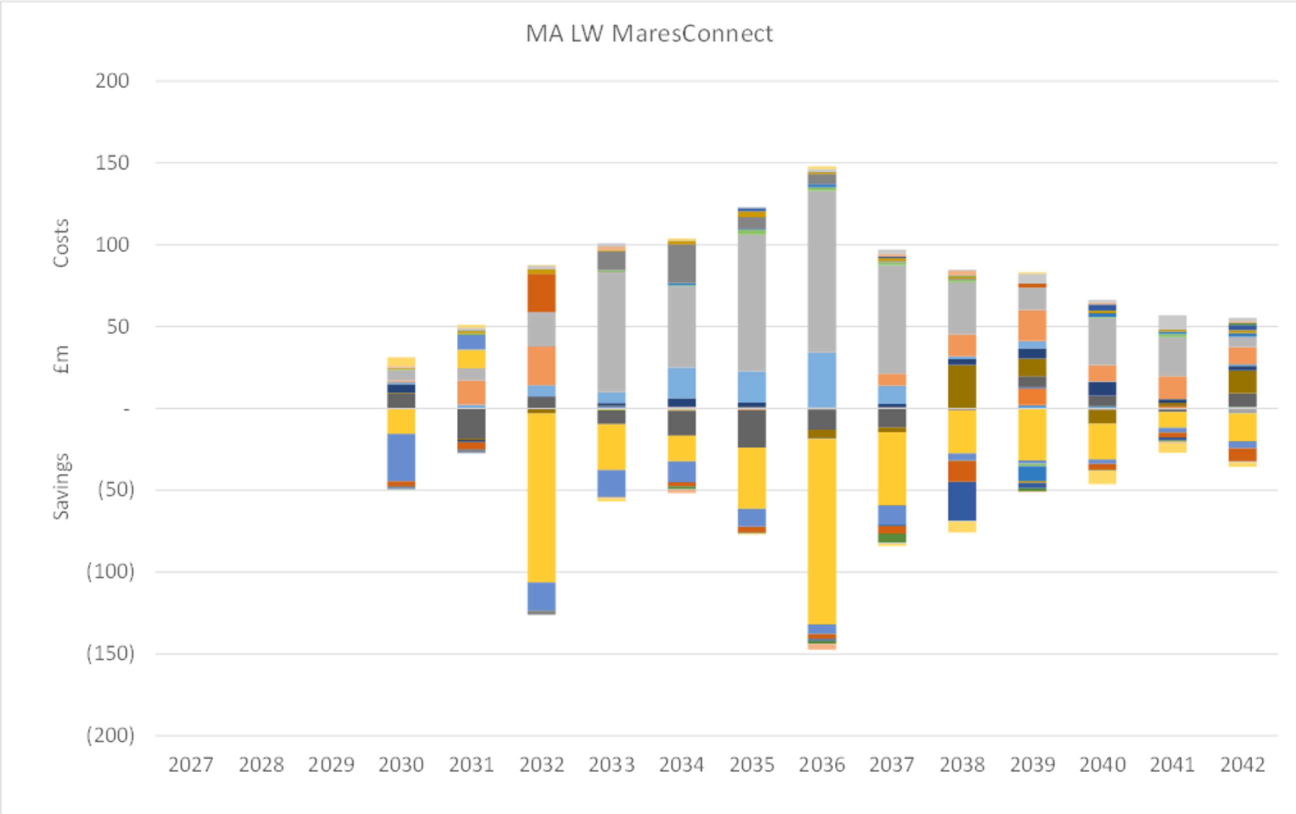

Figure 99: Change in constraint costs by boundary for MaresConnect for the MA case for Leading the Way.

The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for MaresConnect for the Marginal Additional case for the Leading the Way scenario. Each different colour represents the change in constraint costs for a particular boundary. It is important to note that the chart shows changes in constraint costs by boundary, i.e. the difference between constraint costs when the project is included and when the project is excluded.

Compared to the First Additional case, the Marginal Additional shows similar levels of additional constraint costs each year, and an increase in constraint savings for each year. This is because the Marginal Additional case has all of the W3 interconnector and OHA pilot projects included in the supply/demand background, enabling the model to minimise total constraint costs by taking balancing actions across the whole GB network for a wider range of solutions.

In general, for the Marginal Additional case, MaresConnect increases constraint costs on several northern boundaries, but relieves congestion on some midlands boundaries. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

PV system operation

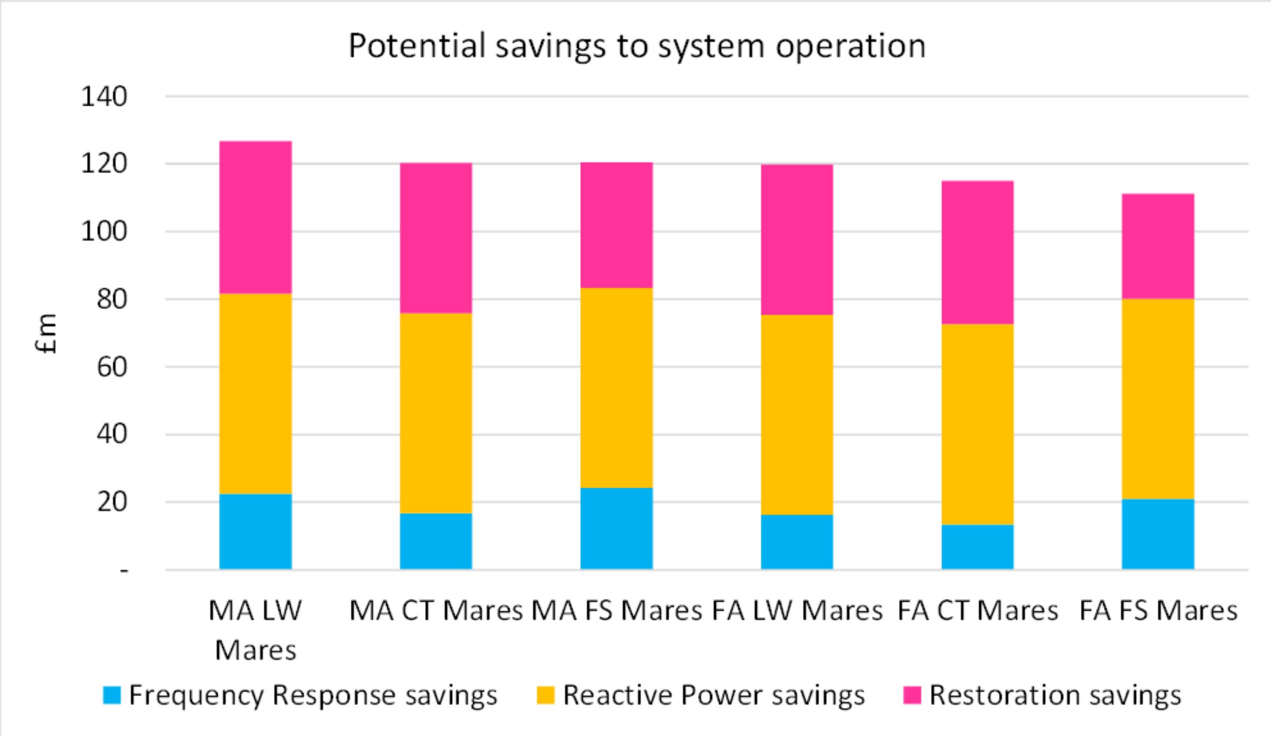

Figure 100: PV potential system operability savings for MaresConnect, Present Value 25-year, real 2022, £m.

The above figure shows the potential savings for frequency response, reactive power and restoration services in present value (25 year, 2022 £m) for MaresConnect for Leading the Way, Consumer Transformation and Falling Short for both the Marginal Additional and First Additional cases. There is considerable uncertainty around forecasting potential system operability benefits over a 25-year time horizon, but the figure shows that there is potentially significant savings in frequency response, reactive power and restoration services.

There is little variation across the three scenarios and also across the First Additional and Marginal Additional cases. This is because the potential system operability savings from the services provided by MaresConnect are less sensitive to flows across the interconnector, whereas the constraint cost impact is highly dependent on the scale and direction of flows across the project.

RES curtailment avoided

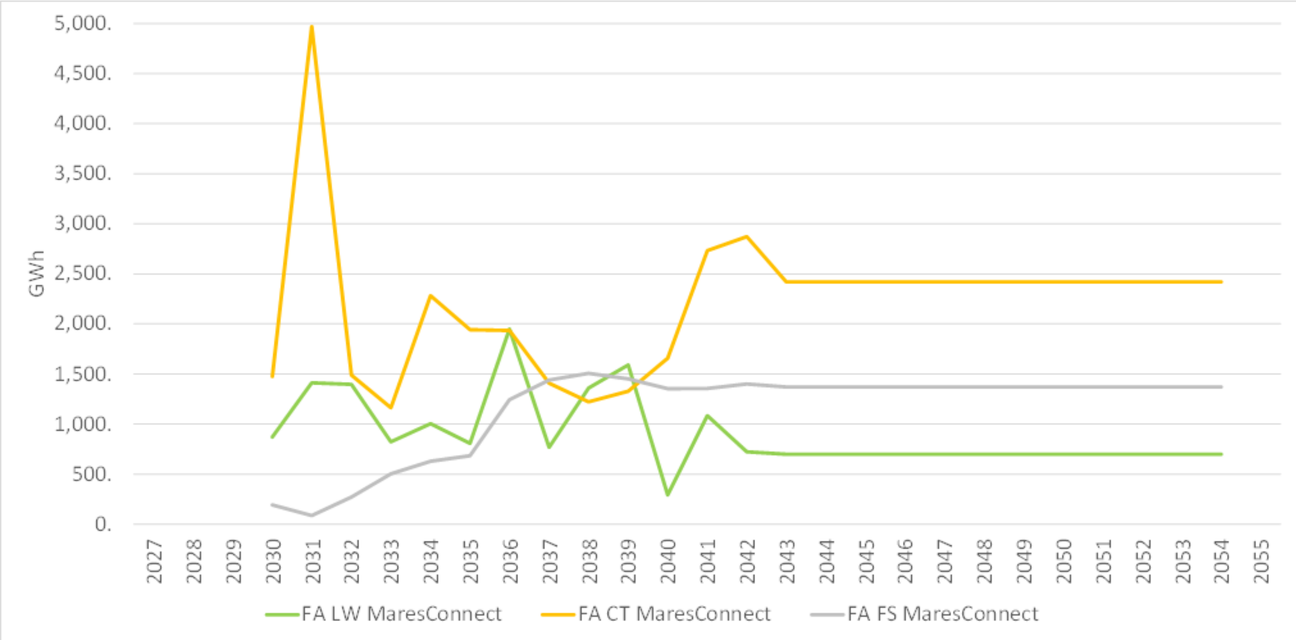

Figure 101: Annual RES curtailment avoided for MaresConnect for the First Additional case.

The above figure shows the renewable energy supply (RES) curtailment avoided on an annual basis for Leading the Way, Consumer Transformation and Falling Short for the First Additional case. Note that beyond 2042, the results are an average of the years 2040, 2041 and 2042, as our detailed modelling with FES22 only extends out to 2042. The figure shows a spike in RES curtailment avoided in Consumer Transformation for 2031: this coincides with the large constraint saving seen across one boundary for that year. The figure shows that the level of annual RES curtailment avoided when MaresConnect is included is approximately between 0.5TWh and 2.5TWh, which equates to approximately between 1.4GWh and 6.8GWh per day.

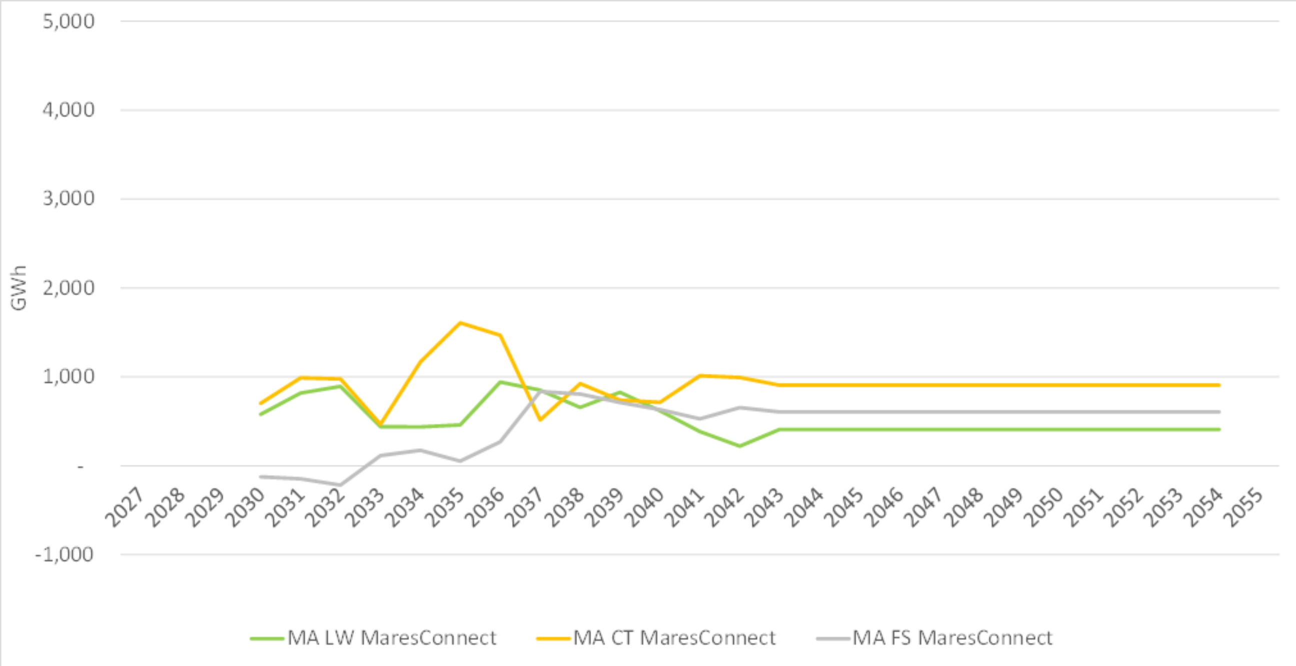

Figure 102: Annual RES curtailment avoided for MaresConnect for the Marginal Additional case.

The above figure shows the renewable energy supply (RES) curtailment avoided on an annual basis for Leading the Way, Consumer Transformation and Falling Short for the Marginal Additional case. Note that beyond 2042, the results are an average of the years 2040, 2041 and 2042, as our detailed modelling with FES22 only extends out to 2042. The figure shows that the level of annual RES curtailment avoided when MaresConnect is included is approximately between 0.5TWh and 1TWh, which equates to approximately between 1.4GWh and 2.7GWh per day.

16. Nautilus

Nautilus is an Offshore Hybrid Asset (OHA) pilot project. It has a capacity of 1.4GW and connects to Belgium.

PV constraint costs

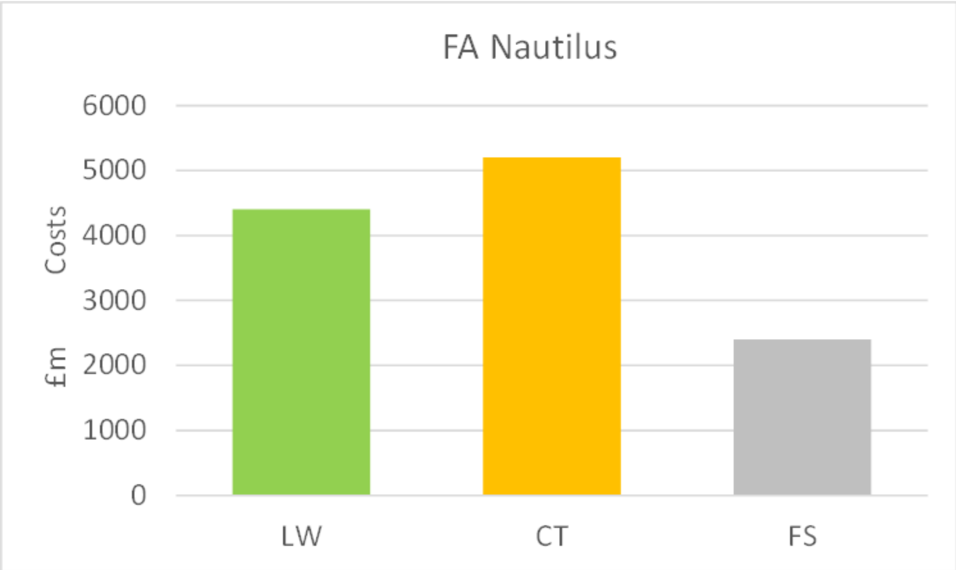

Figure 103: PV additional constraint costs due to Nautilus for the First Additional case, Present Value 25-year, real 2022, £m.

The above figure shows the additional constraint costs with the inclusion of Nautilus for the FA case. In the Leading the Way (LW) scenario constraint costs are increased by £4.4bn, in Consumer Transformation (CT) by £5.2bn and in the Falling Short (FS) scenario by £2.4bn.

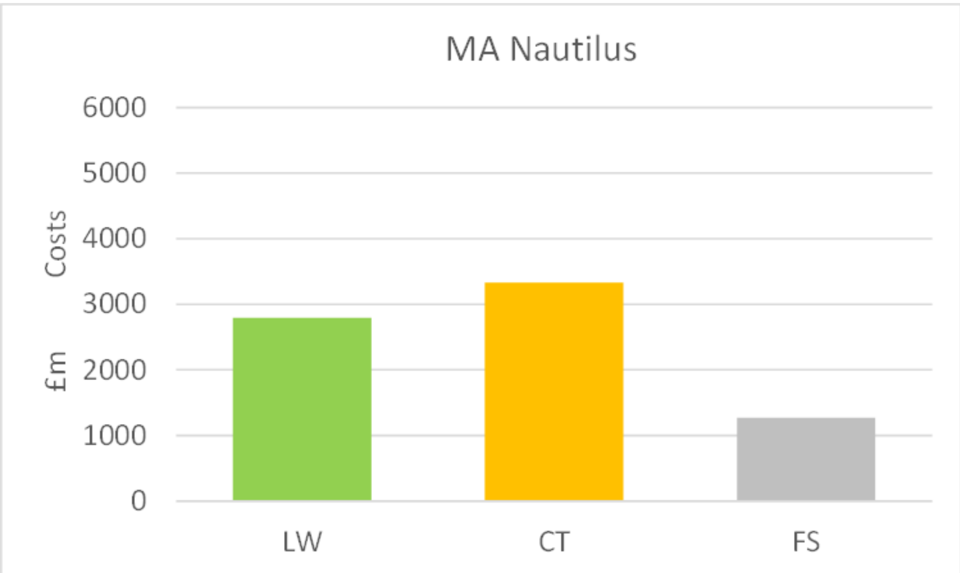

Figure 104: PV additional constraint costs due to Nautilus for the Marginal Additional case, Present Value 25-year, real 2022, £m.

The above figure shows the additional constraint costs with the inclusion of Nautilus for the MA case. Additional constraint costs are significantly lower than in the FA case. This is because the inclusion of the other OHA and Window 3 projects within the supply demand mix reduces the impact any one interconnector has on constraint costs. In the Leading the Way (LW) scenario constraint costs are increased by £2.8bn, in Consumer Transformation (CT) by £3.3bn and in the Falling Short (FS) scenario by £1.3bn.

Annual constraint costs

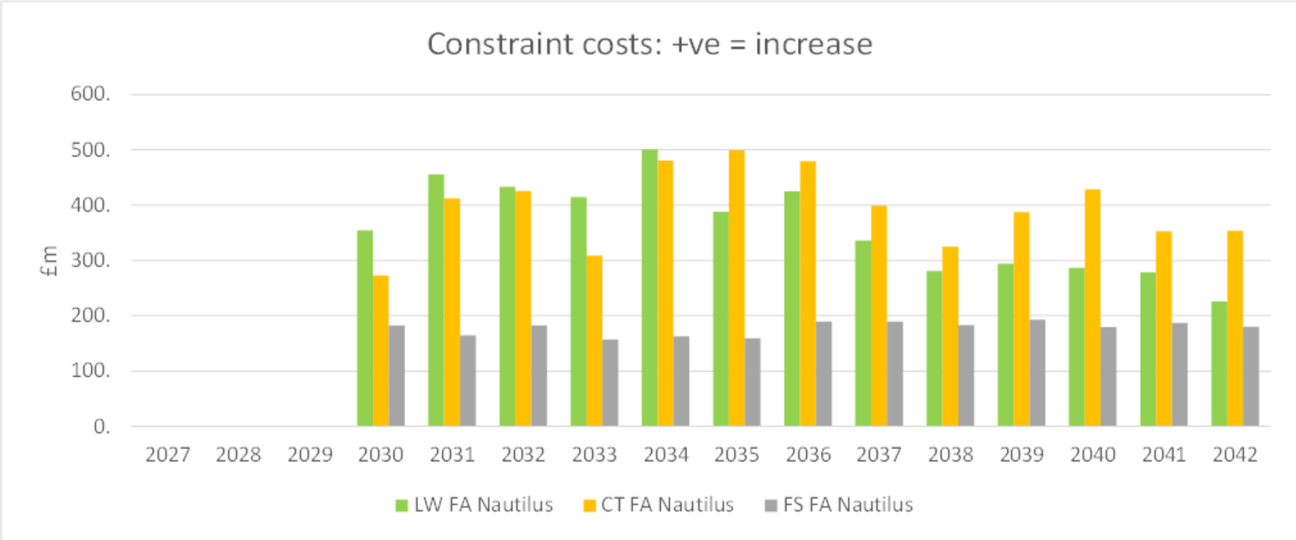

Figure 105: Additional annual constraint costs due to Nautilus for the First Additional case.

The above figure shows that for the First Additional case, Nautilus results in an increase in constraint costs of between £300m to £400m (undiscounted) in CT and LW in the years 2031 to 2040. In FS constraint cost increases are much lower, at approximately £150m to £200m (undiscounted) each year.

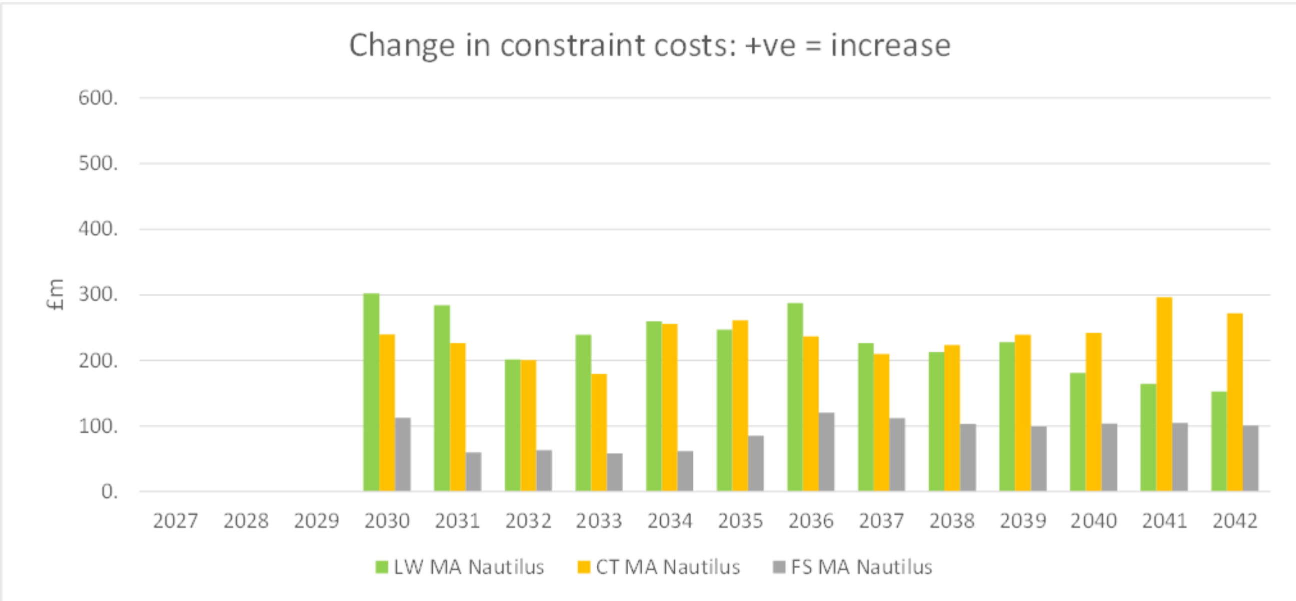

Figure 106: Additional annual constraint costs due to Nautilus for the Marginal Additional case.

The above figure shows that in the Marginal Additional case, Nautilus results in increased constraint costs of between £200m and £250m (undiscounted) in the years 2030 to 2039 in LW and CT. FS results in increased constraint costs of approximately £100m per year or less (undiscounted).

Annual import and export flows for dispatch and redispatch

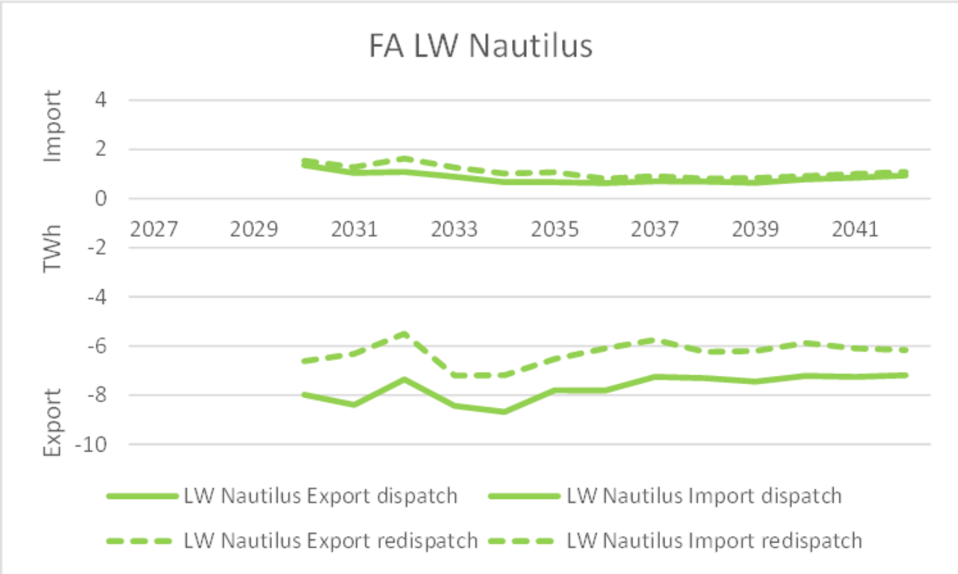

Figure 107: Annual import and export flows for Nautilus in the FA case for Leading the Way.

The above figure shows Nautilus has high exports and low imports in the dispatch for Leading the Way for the First Additional case. The redispatch shows a significant reduction in exports and small increases in imports.

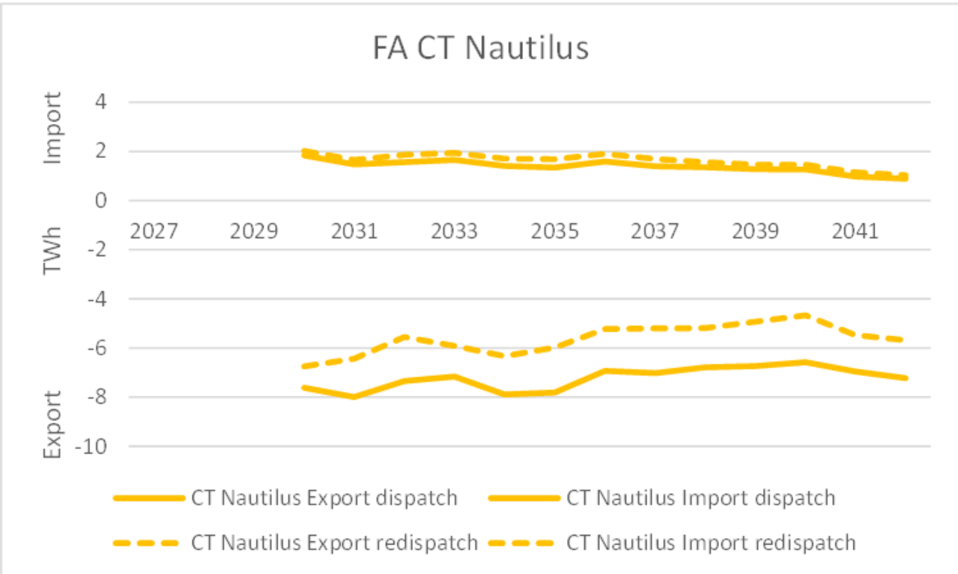

Figure 108: Annual import and export flows for Nautilus in the FA case for Consumer Transformation.

The above figure shows Nautilus has high exports and low imports in the dispatch for Consumer Transformation for the First Additional case. The redispatch shows a significant reduction in exports and small increases in imports.

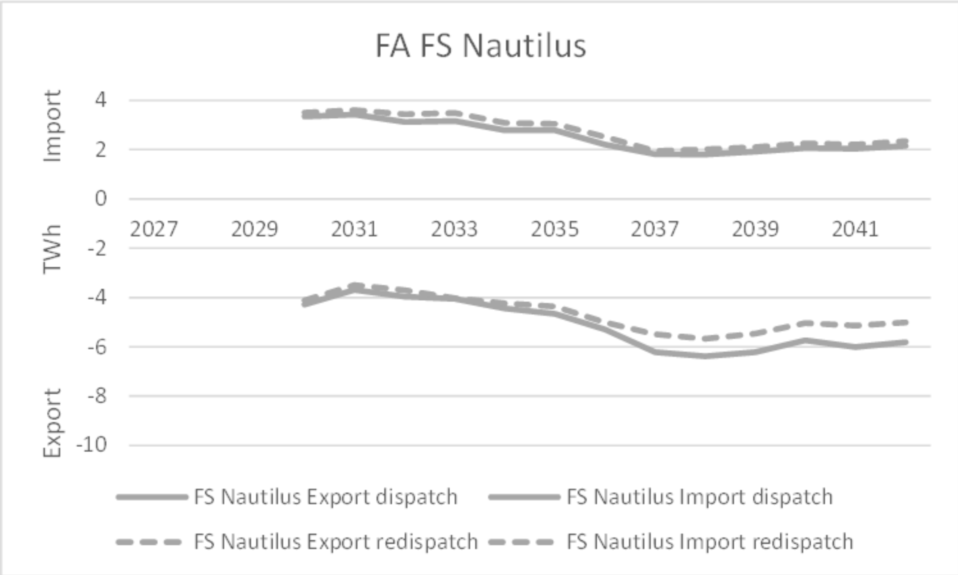

Figure 109: Annual import and export flows for Nautilus in the FA case for Falling Short.

The above figure shows that for the First Additional case Nautilus has increasing levels of exports over the forecast period up to 2038 and decreasing imports up to 2037 in the dispatch for Falling Short. The redispatch shows a slight reduction in exports in the later years and a small increase in imports in the early years.

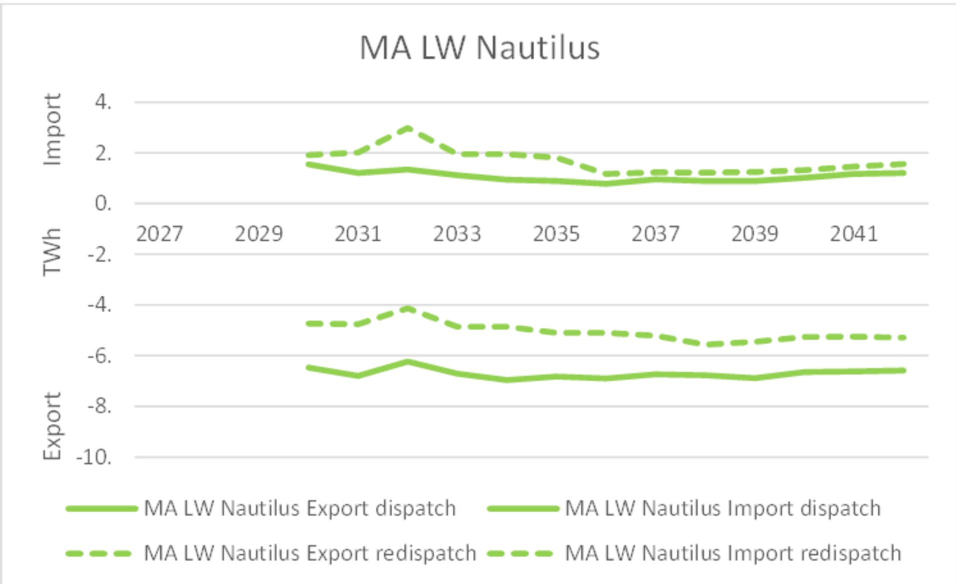

Figure 110: Annual import and export flows for Nautilus in the MA case for Leading the Way.

The above figure shows that for the Marginal Additional case, Nautilus has high exports, but lower than in the First Additional case, and low imports in the dispatch similar to those shown in the First Additional case for Leading the Way. The redispatch shows significant reductions in exports, especially in the early years and an increase in imports, particularly from 2032 to 2035.

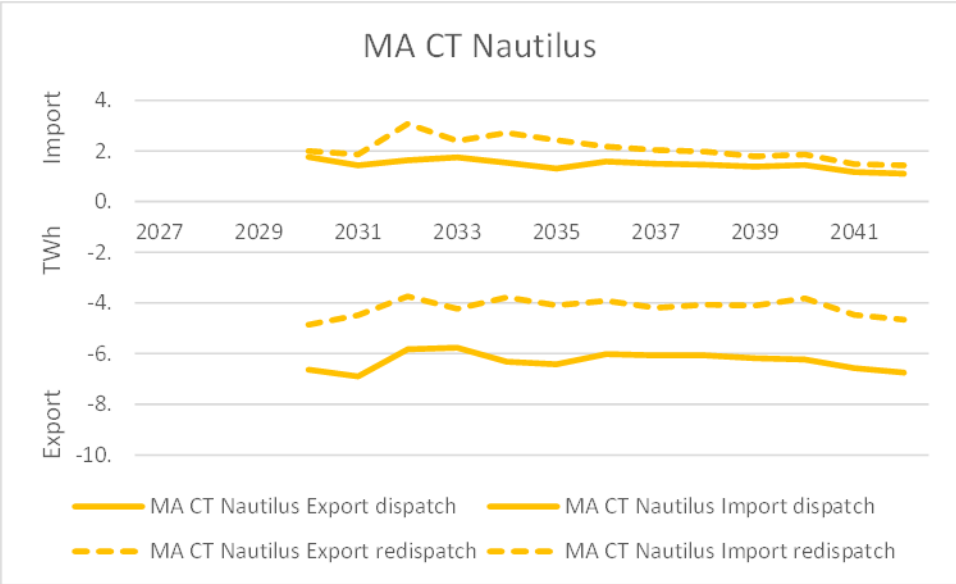

Figure 111: Annual import and export flows for Nautilus in the MA case for Consumer Transformation.

The above figure shows that for the Marginal Additional case for Consumer Transformation, Nautilus has high exports, but lower than in the First Additional case, and low imports in the dispatch, similar to those shown in the First Additional case for Consumer Transformation. The redispatch shows significant reductions in exports across all the years and an increase in imports, particularly from 2032 to 2035.

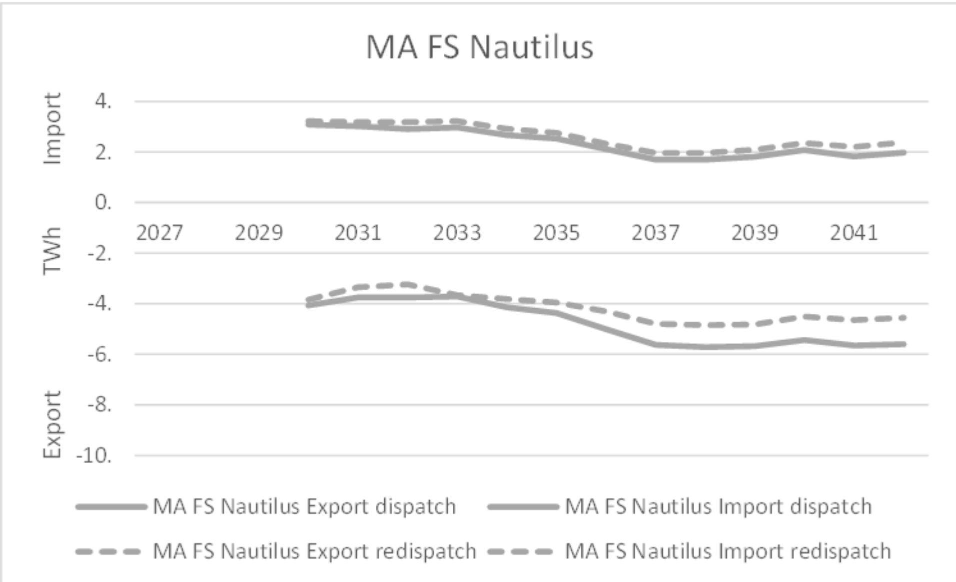

Figure 112: Annual import and export flows for Nautilus in the MA case for Falling Short.

The above figure shows that for the Marginal Additional case Nautilus has increasing levels of exports over the forecast period up to 2038 and decreasing imports up to 2037 in the dispatch for Falling Short. The redispatch shows a slight reduction in exports in the later years and a small increase in imports across all the years.

Change in constraint costs by boundary

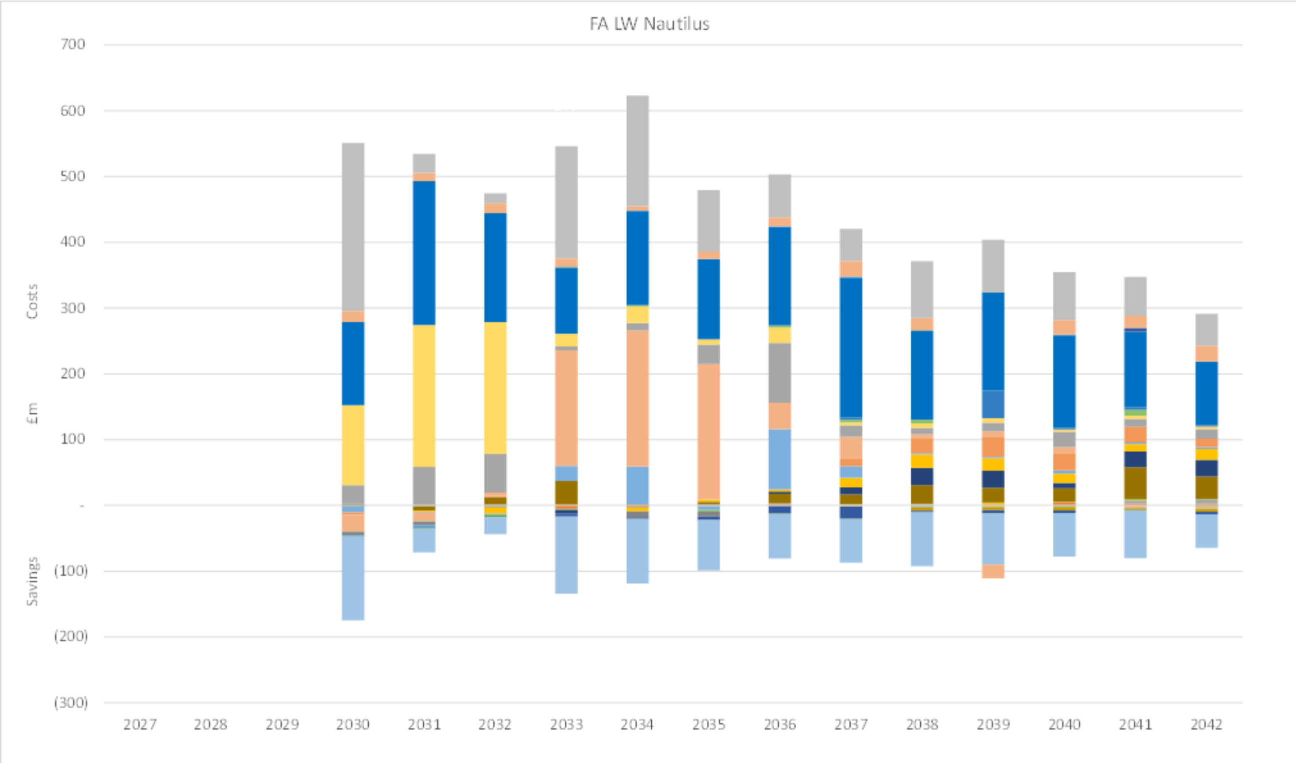

Figure 113: Change in constraint costs by boundary for Nautilus for the FA case for Leading the Way.

The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for Nautilus for the First Additional case for the Leading the Way scenario. Each different colour represents the change in constraint costs for a particular boundary. It is important to note that the chart shows changes in constraint costs by boundary, i.e. the difference between constraint costs when the project is included and when the project is excluded.

The figure shows that Nautilus increases constraint costs on certain boundaries but also reduces constraint costs on others. Whether the impact is an increase in constraint costs or a reduction in constraint costs for a particular boundary, changes from year to year. The size of change in constraint costs by boundary can also vary significantly from year to year. This is shown clearly in the years 2035 to 2037. The figure also shows that the specific boundaries that have the greatest impact on the total change in constraint costs can vary from year to year. These factors are a result of the changes in demand, supply and network capability over time.

In general, Nautilus increases constraint costs on several midland and southern boundaries but relieves congestion on other southern boundaries. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

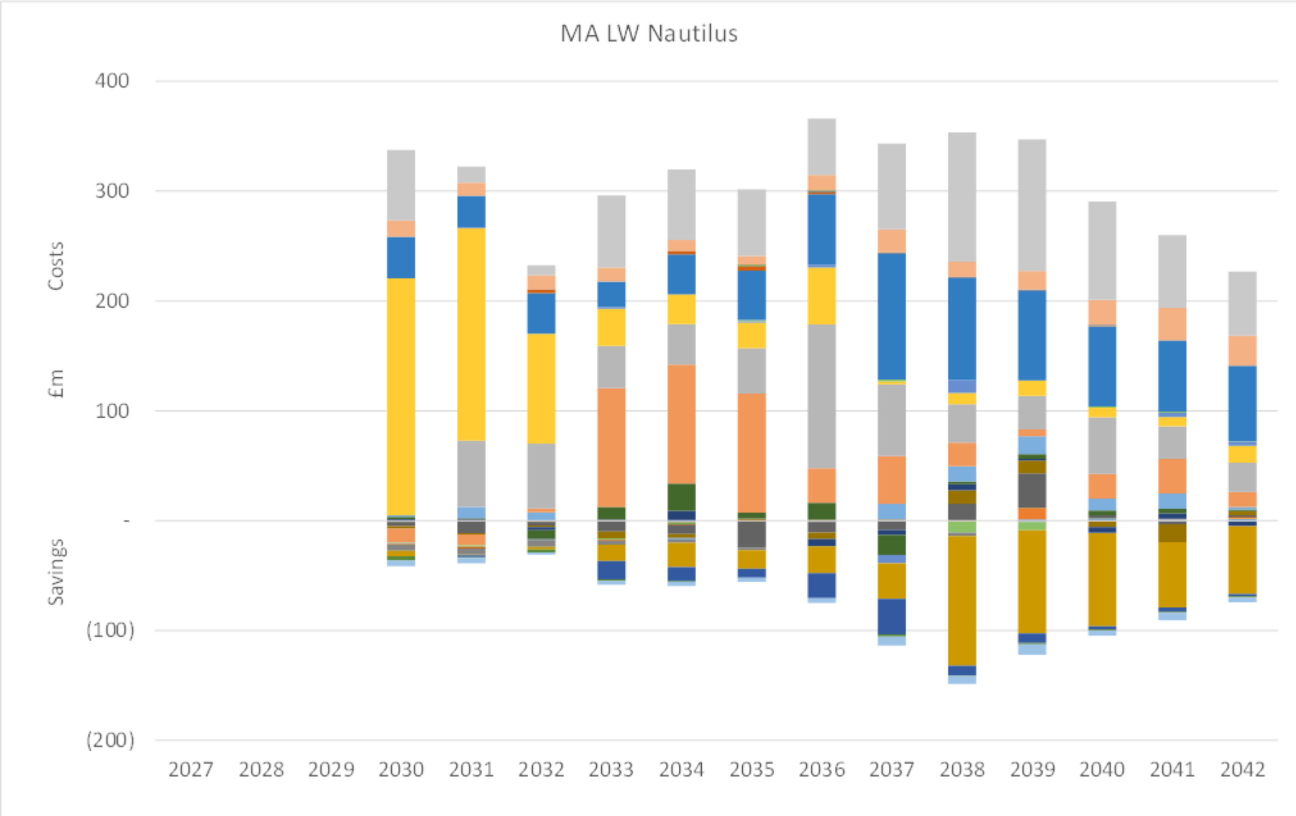

Figure 114: Change in constraint costs by boundary for Nautilus for the MA case for Leading the Way.

The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for Nautilus for the Marginal Additional case for the Leading the Way scenario. Each different colour represents the change in constraint costs for a particular boundary. It is important to note that the chart shows changes in constraint costs by boundary, i.e. the difference between constraint costs when the project is included and when the project is excluded.

Compared to the First Additional case, the Marginal Additional shows an overall reduction in additional constraint costs each year, and similar constraint savings for each year. This is because the Marginal Additional case has all of the W3 interconnector and OHA pilot projects included in the supply/demand background, enabling the model to minimise total constraint costs by taking balancing actions across the whole GB network for a wider range of solutions.

In general, for the Marginal Additional case, Nautilus increases constraint costs on several midland and southern boundaries but relieves congestion on other southern boundaries. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

PV system operation

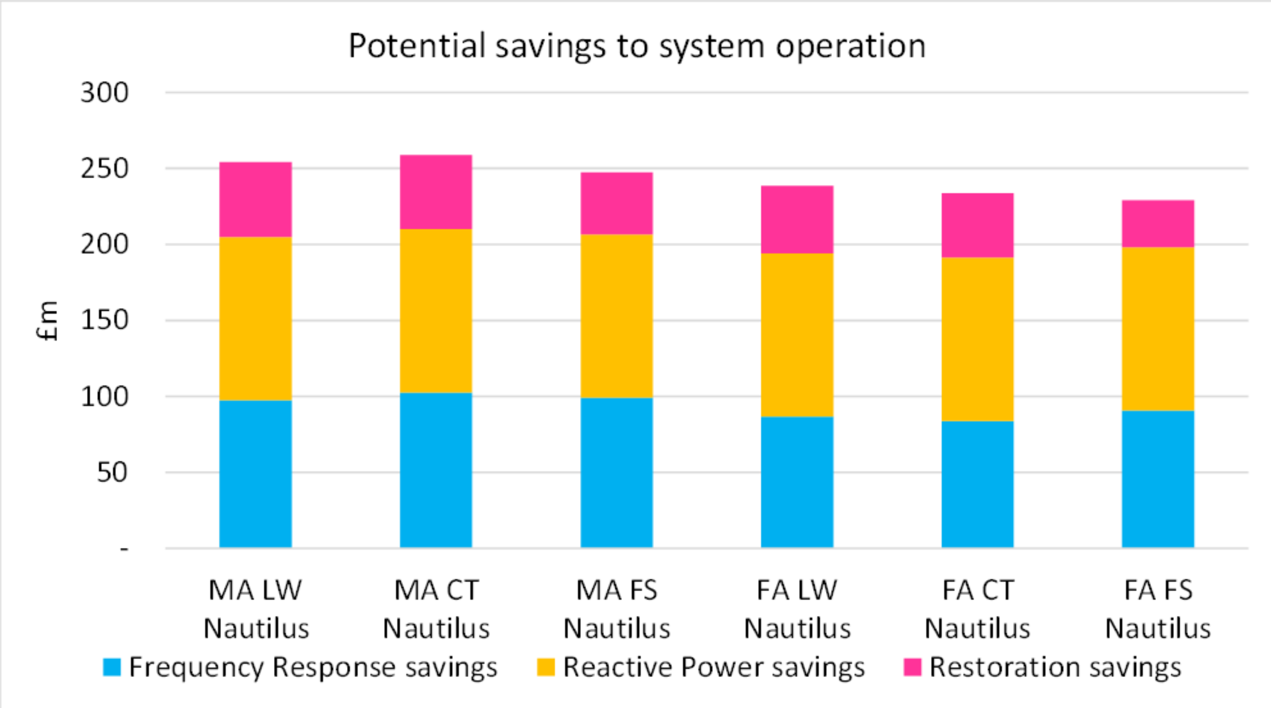

Figure 115: PV potential system operability savings for Nautilus, Present Value 25-year, real 2022, £m.

The above figure shows the potential savings for frequency response, reactive power and restoration services in present value (25 year, 2022 £m) for Nautilus for Leading the Way, Consumer Transformation and Falling Short for both the Marginal Additional and First Additional cases. There is considerable uncertainty around forecasting potential system operability benefits over a 25-year time horizon, but the figure shows that there is potentially significant savings in frequency response, reactive power and restoration services.

There is little variation across the three scenarios and also across the First Additional and Marginal Additional cases. This is because the potential system operability savings from the services provided by Nautilus are less sensitive to flows across the OHA, whereas the constraint cost impact is highly dependent on the scale and direction of flows across the project.

RES curtailment avoided

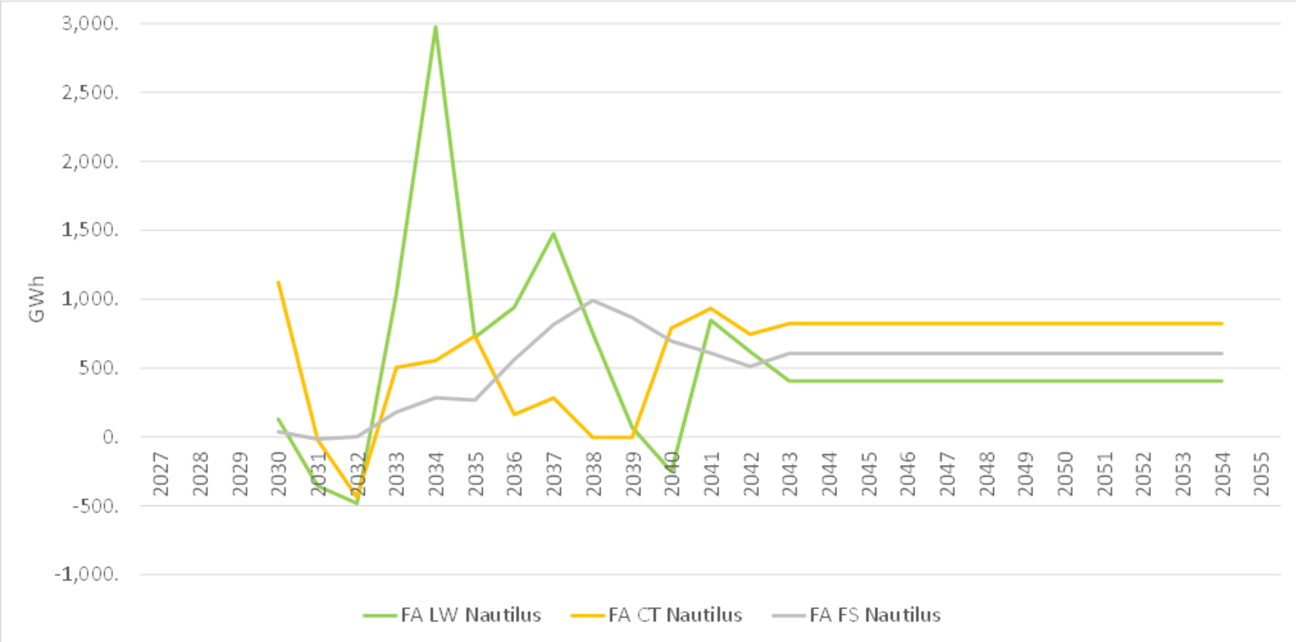

Figure 116: Annual RES curtailment avoided for Nautilus for the First Additional case.

The above figure shows the renewable energy supply (RES) curtailment avoided on an annual basis for Leading the Way, Consumer Transformation and Falling Short for the First Additional case. Note that beyond 2042, the results are an average of the years 2040, 2041 and 2042, as our detailed modelling with FES22 only extends out to 2042. The figure shows that the level of annual RES curtailment avoided when Nautilus is included is approximately between 0.5TWh and 1TWh, which equates to approximately between 1.4GWh and 2.7GWh per day.

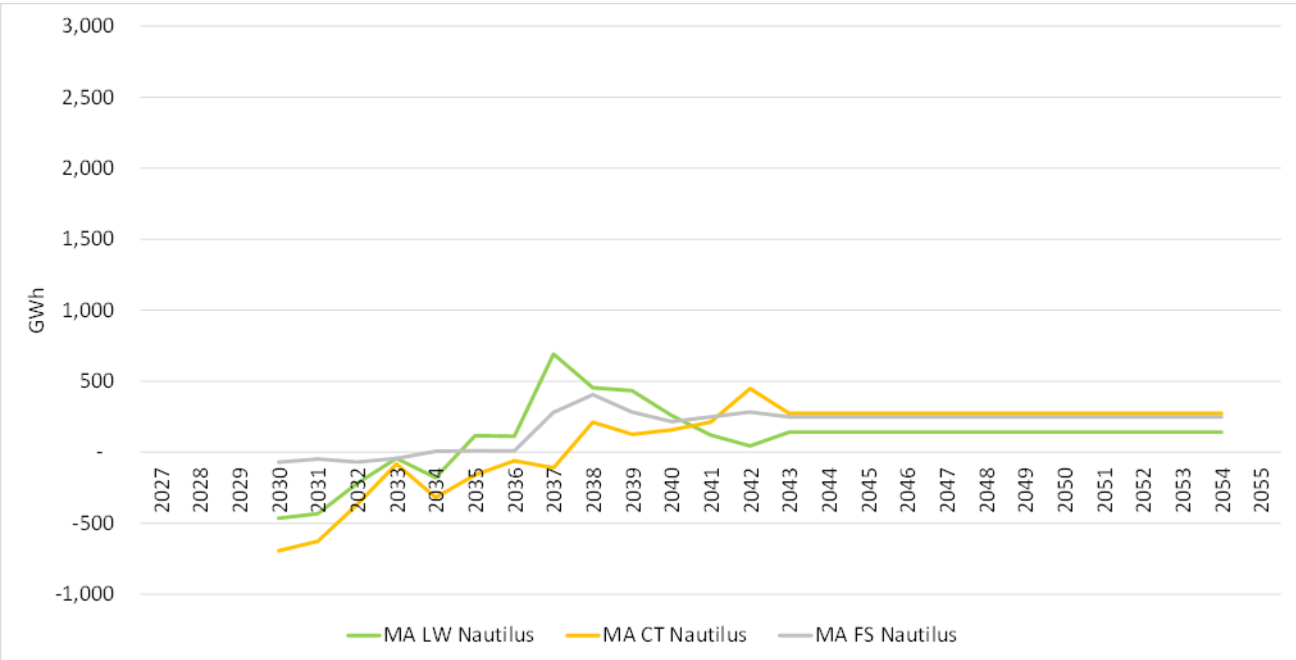

Figure 117: Annual RES curtailment avoided for Nautilus for the Marginal Additional case.

The above figure shows the renewable energy supply (RES) curtailment avoided on an annual basis for Leading the Way, Consumer Transformation and Falling Short for the Marginal Additional case. Note that beyond 2042, the results are an average of the years 2040, 2041 and 2042, as our detailed modelling with FES22 only extends out to 2042. The figure shows that the level of annual RES curtailment avoided when Nautilus is included is approximately between 0.25TWh and 0.5TWh, which equates to approximately between 0.7GWh and 1.4GWh per day. Up to 2034 in all three scenarios, Nautilus results in an increase in RES curtailment.

17. NU-Link

NU-Link is a W3 interconnector project. It has a capacity of 1.2GW and connects to The Netherlands.

PV constraint costs

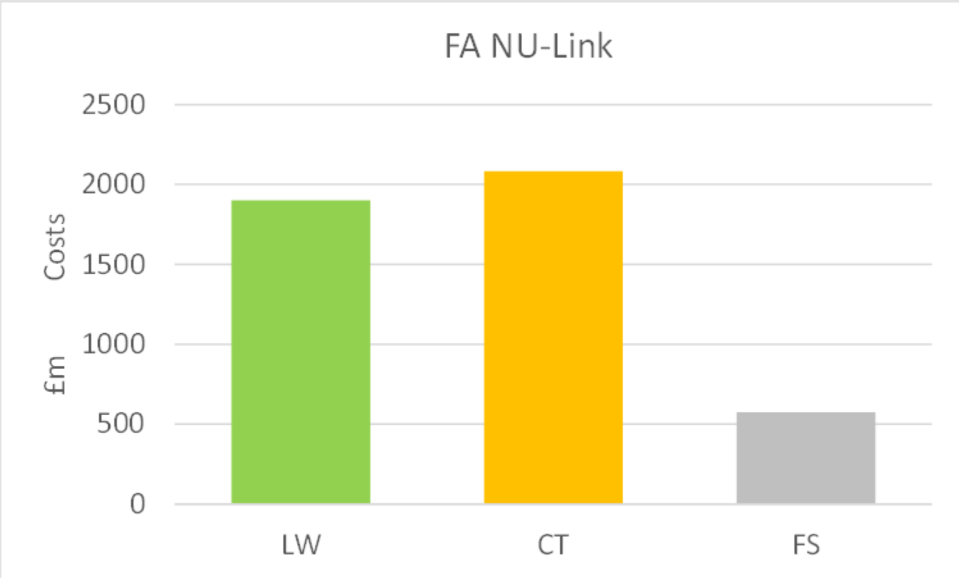

Figure 118: PV additional constraint costs due to NU-Link for the First Additional case, Present Value 25-year, real 2022, £m.

The above figure shows the additional constraint costs with the inclusion of NU-Link for the FA case. In the Leading the Way (LW) scenario constraint costs are increased by £1.9bn, in Consumer Transformation (CT) by £2.08bn and in the Falling Short (FS) scenario by £0.57bn.

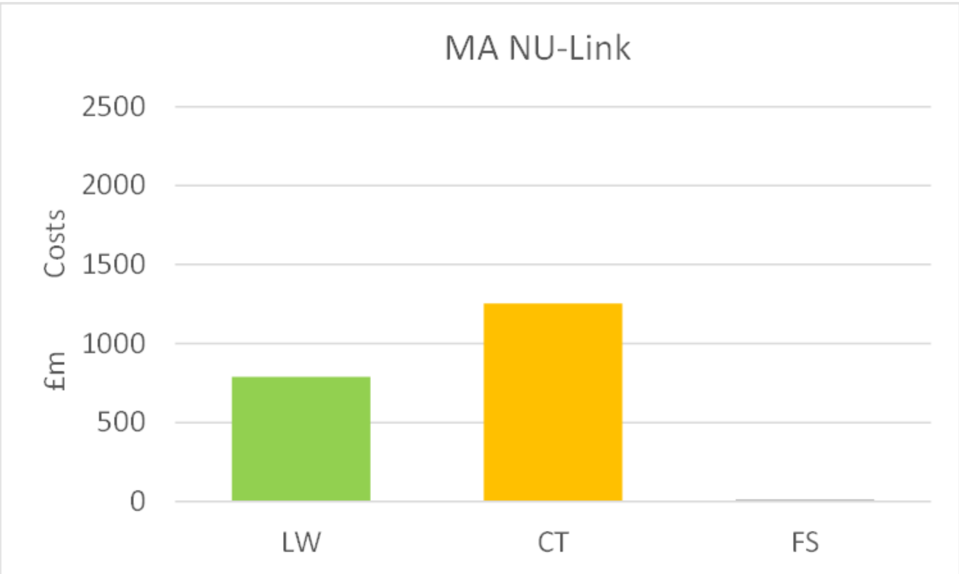

Figure 119: PV additional constraint costs due to NU-Link for the Marginal Additional case, Present Value 25-year, real 2022, £m.

The above figure shows the additional constraint costs with the inclusion of NU-Link for the MA case. Additional constraint costs are significantly lower than in the FA case. This is because the inclusion of the other OHA and Window 3 projects within the supply demand mix reduces the impact any one interconnector has on constraint costs. In the Leading the way scenario (LW) constraint costs are increased by £0.79bn, in Consumer Transformation (CT) by £1.25bn and in the Falling Short (FS) scenario by £0.01bn.

Annual constraint costs

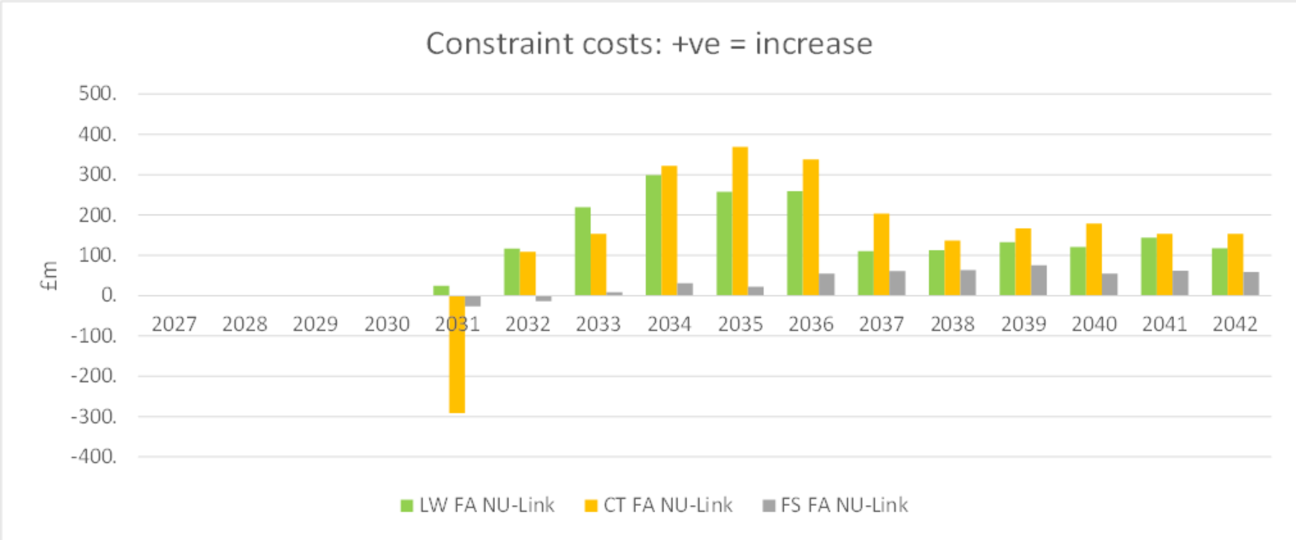

Figure 120: Additional annual constraint costs due to NU-Link for the First Additional case.

The above figure shows that for the First Additional case, NU-Link results in an increase in constraint costs of approximately £200m to £300m (undiscounted) in CT and LW in the years 2034 to 2036. The high level of constraint cost reduction in 2031 in CT is because the inclusion of NU-Link enables the model to produce a solution that decreases constraints across potentially one or more boundaries. The unique combination of electricity supply, demand and boundary capabilities seen in 2031 for CT is not replicated in any other years, suggesting that for later years either supply or demand patterns or boundary capabilities have changed. This is explored in subsequent charts in this section. In FS constraint cost increases are much lower, with small savings in 2031 and 2032.

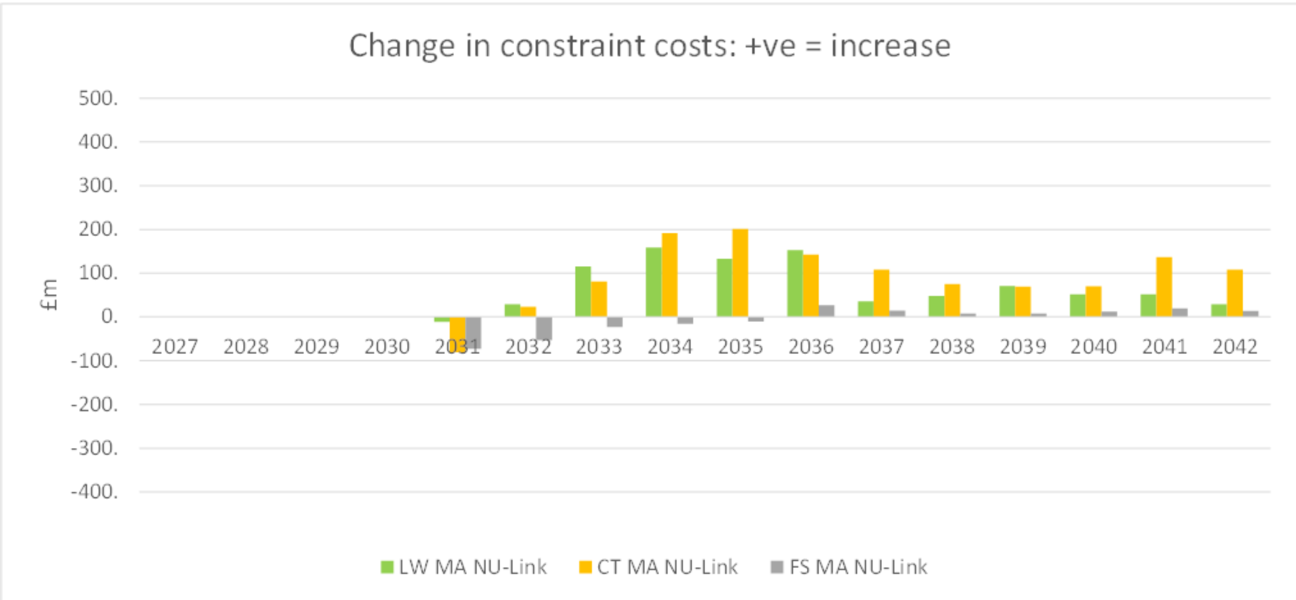

Figure 121: Additional annual constraint costs due to NU-Link for the Marginal Additional case.

The above figure shows that for the Marginal Additional case, NU-Link results in an increase in constraint costs of approximately £100m to £200m (undiscounted) in CT and LW for the years 2034 to 2036. FS shows constraint savings for the years 2031 to 2035, and for the other years shows very low levels of additional constraint costs compared to LW and CT.

Annual import and export flows for dispatch and redispatch

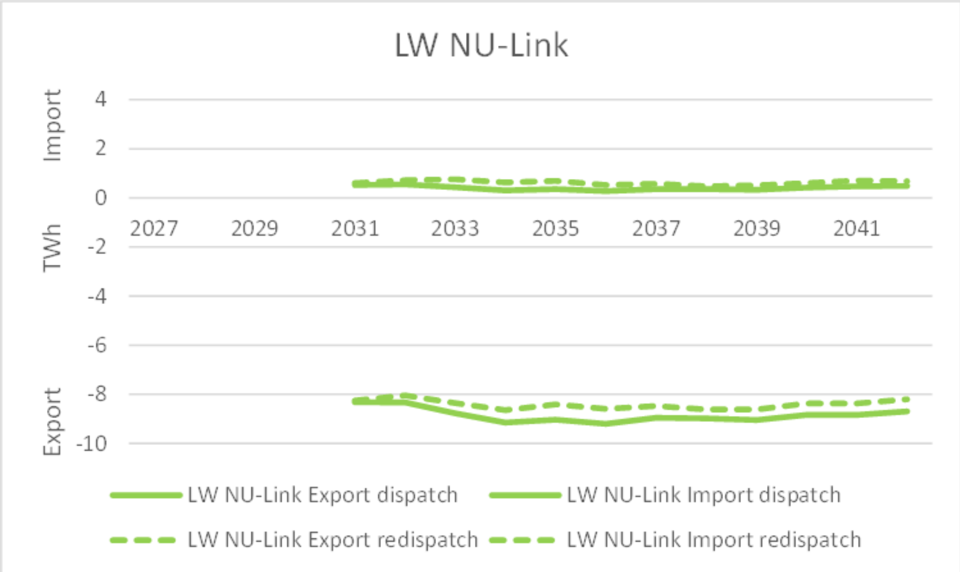

Figure 122: Annual import and export flows for NU-Link in the FA case for Leading the Way.

The above figure shows NU-Link has high exports and very low imports in the dispatch for Leading the Way for the First Additional case. The redispatch shows a small reduction in exports and a very small increase in imports.

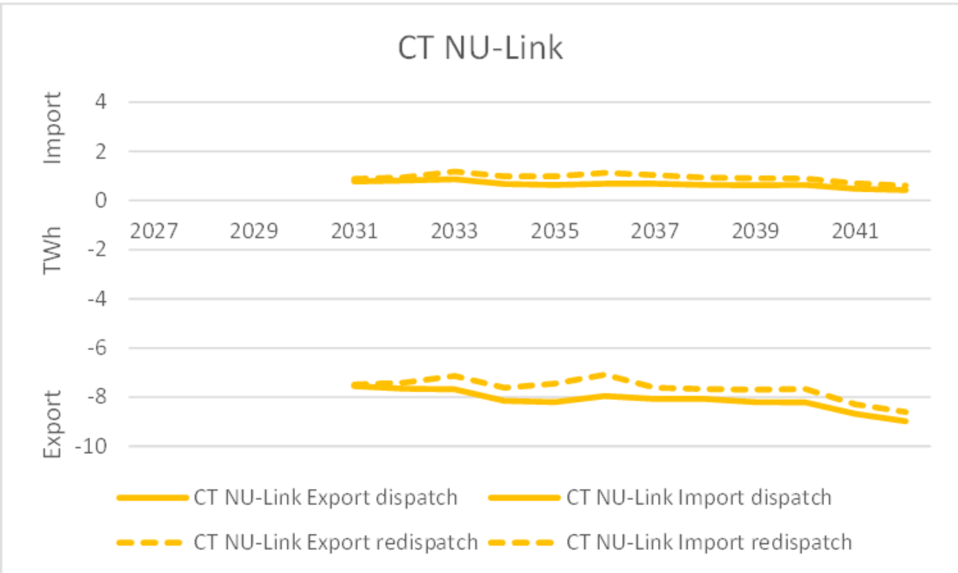

Figure 123: Annual import and export flows for NU-Link in the FA case for Consumer Transformation.

The above figure shows NU-Link has high exports and very low imports in the dispatch for Consumer Transformation for the First Additional case. The redispatch shows a small reduction in exports and a very small increase in imports.

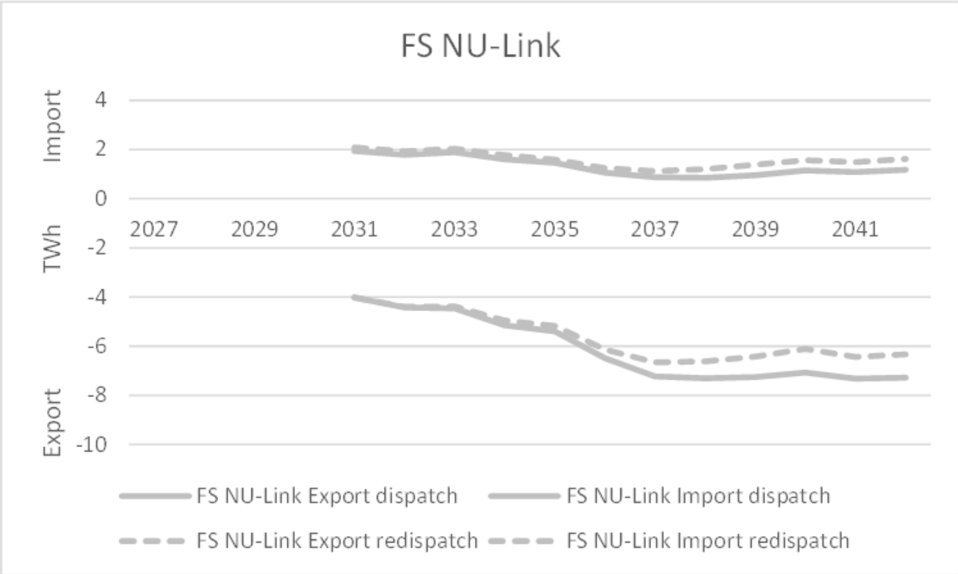

Figure 124: Annual import and export flows for NU-Link in the FA case for Falling Short.

The above figure shows that for the First Additional case NU-Link has increasing levels of exports over the forecast period up to 2037 and decreasing imports up to 2037 in the dispatch for Falling Short. The redispatch shows a slight reduction in exports in the later years and a small increase in imports in the later years.

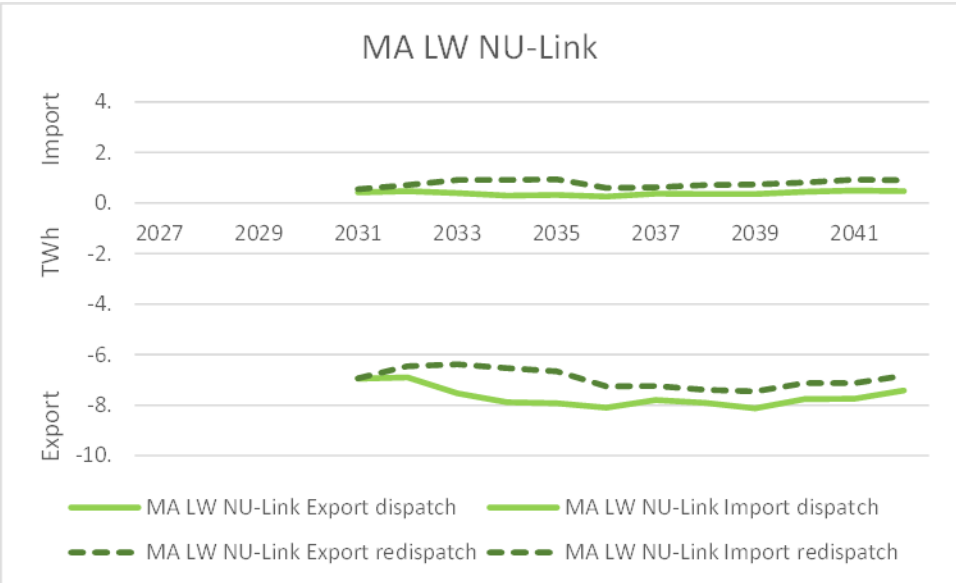

Figure 125: Annual import and export flows for NU-Link in the MA case for Leading the Way.

The above figure shows that for the Marginal Additional case, NU-Link has high exports, but lower than in the First Additional case, and very low imports in the dispatch, similar to those shown in the First Additional case for Leading the Way. The redispatch shows significant reductions in exports, especially in the early years and a small increase in imports, particularly from 2032 to 2035.

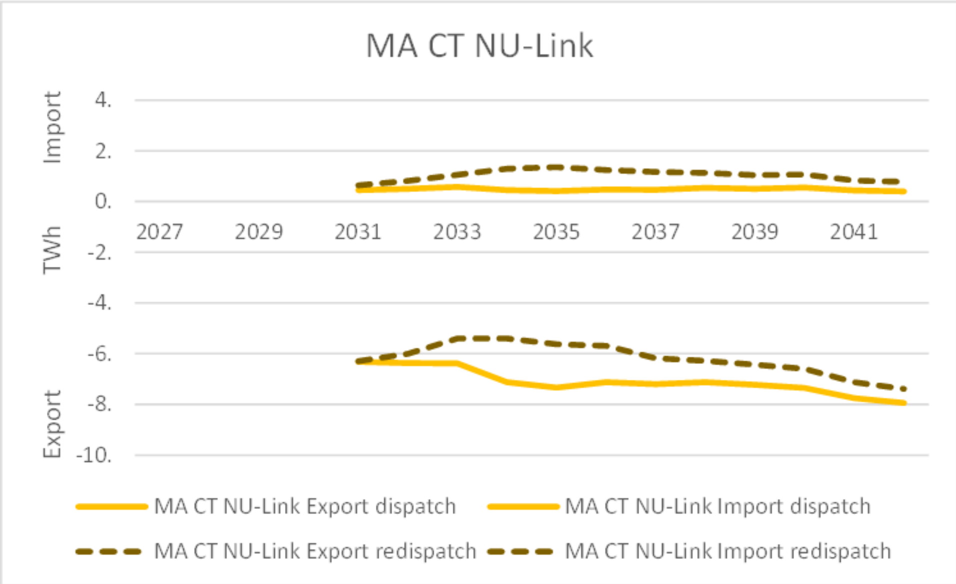

Figure 126: Annual import and export flows for NU-Link in the MA case for Consumer Transformation.

The above figure shows that for the Marginal Additional case, NU-Link has high exports, but lower than in the First Additional case, and very low imports in the dispatch, similar to those shown in the First Additional case for Consumer Transformation. The redispatch shows significant reductions in exports, especially in the early years and a small increase in imports.

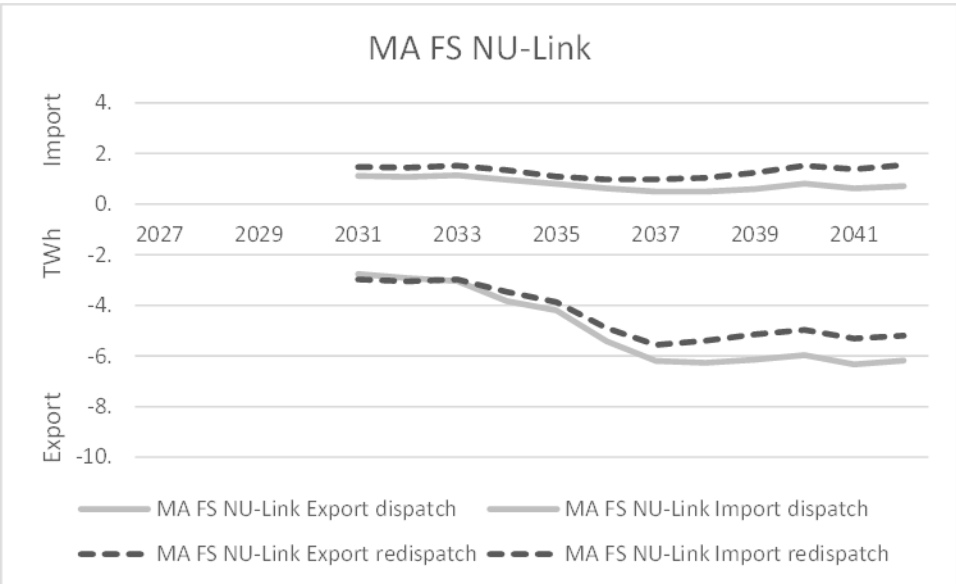

Figure 127: Annual import and export flows for NU-Link in the MA case for Falling Short.

The above figure shows that for the Marginal Additional case, NU-Link has increasing exports, but lower than in the First Additional case, and low imports in the dispatch, slightly lower than those seen in the First Additional case for Falling Short. The redispatch shows some reduction in exports, especially in the later years and a small increase in imports.

Change in constraint costs by boundary

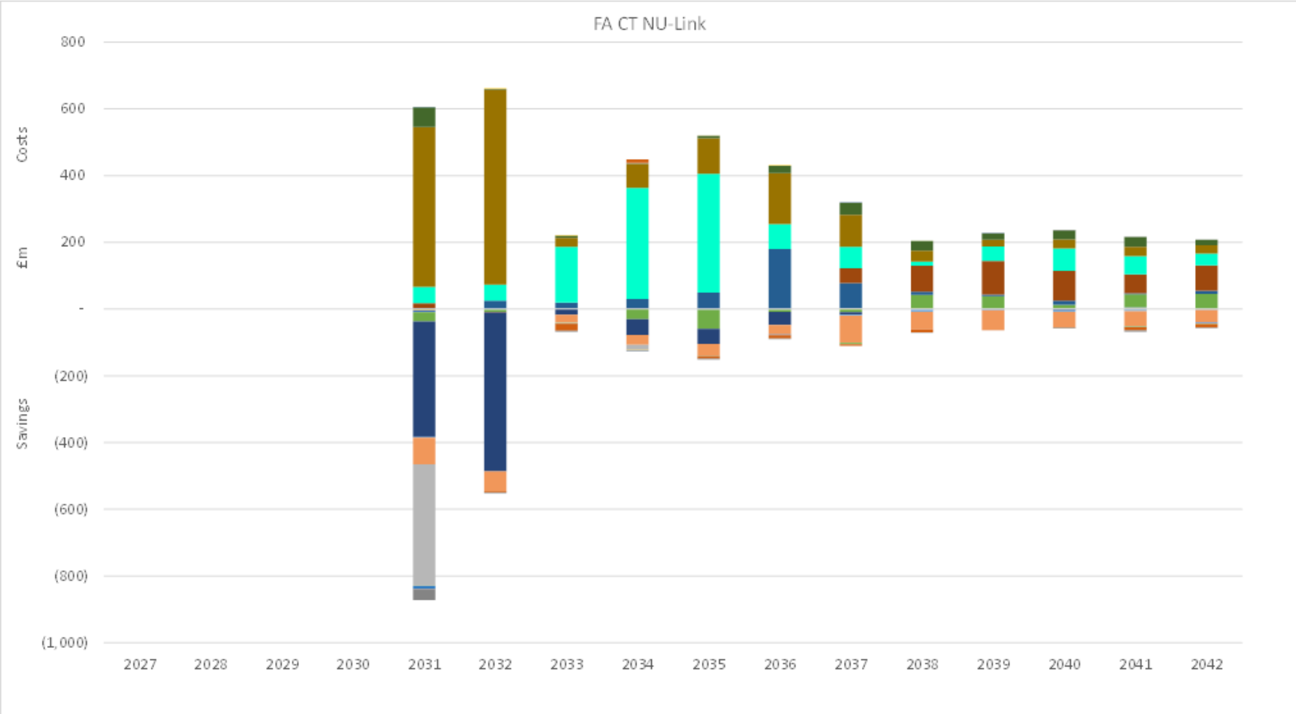

Figure 128: Change in constraint costs by boundary for NU-Link for the FA case for Consumer Transformation.

The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for NU-Link for the First Additional case for the Consumer Transformation scenario. Each different colour represents the change in constraint costs for a particular boundary. It is important to note that the chart shows changes in constraint costs by boundary, i.e. the difference between constraint costs when the project is included and when the project is excluded.

The figure shows that NU-Link increases constraint costs on certain boundaries but also reduces constraint costs on others. Whether the impact is an increase in constraint costs or a reduction in constraint costs for a particular boundary, changes from year to year. The size of change in constraint costs by boundary can also vary significantly from year to year. This is shown clearly in the years 2031 to 2033. The figure also shows that the specific boundaries that have the greatest impact on the total change in constraint costs can vary from year to year. These factors are a result of the changes in demand, supply and network capability over time.

The figure shows that the large constraint saving previously highlighted in Figure 120 for the year 2031 is driven by savings across two boundaries, in this case a Welsh and a midland boundary. The saving only occurs for a single year suggesting the combination of supply, demand and boundary capabilities that enable such a significant saving across both boundaries when NU-Link is included only exist for 2031, although significant savings are seen in one of the boundaries in 2032 also. In later years, supply and demand patterns and boundary capabilities will have evolved such that the model is no longer able to produce the lowest total cost solution by significantly reducing constraint costs across those particular boundaries when NU-Link is included.

In general, NU-Link increases constraint costs on several northern boundaries but relieves congestion on certain midlands and one Welsh boundary. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

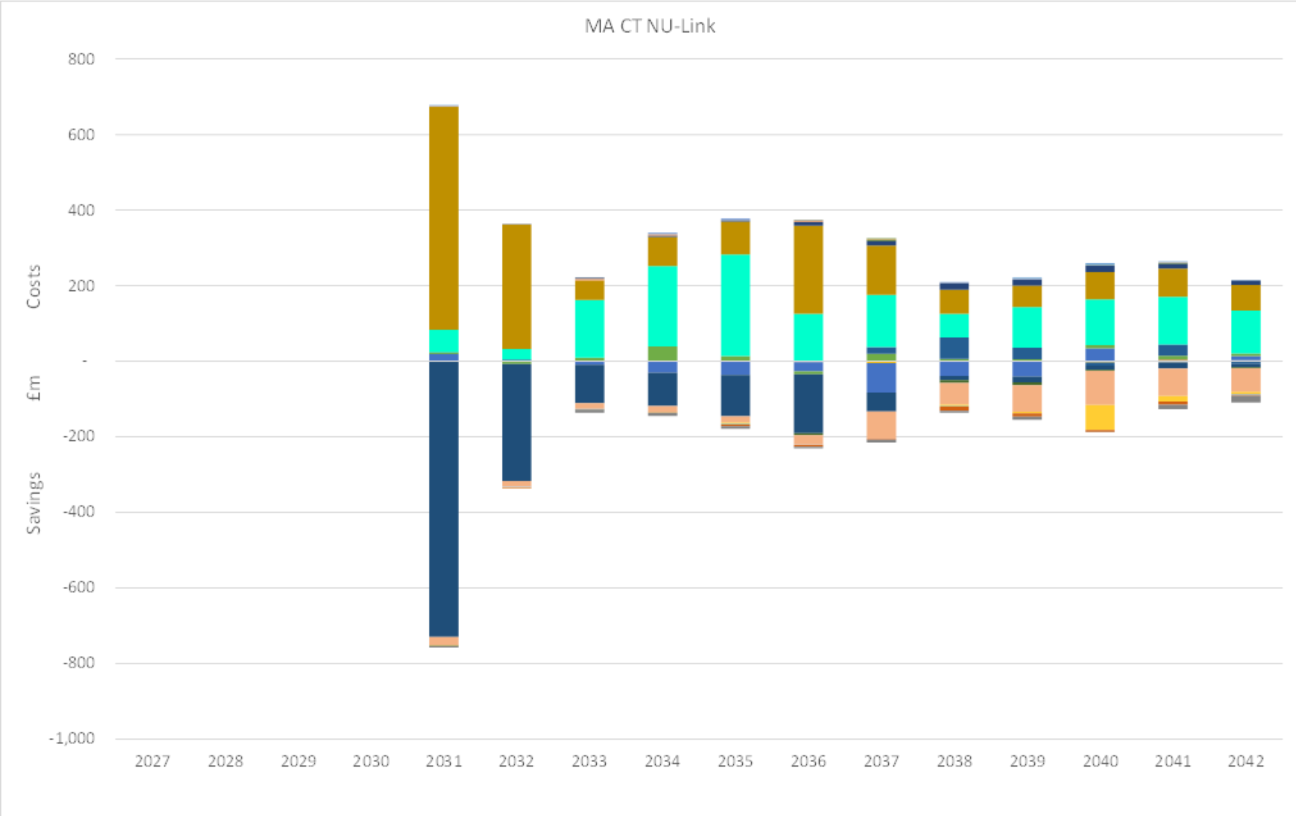

Figure 129: Change in constraint costs by boundary for NU-Link for the MA case for Consumer Transformation.

The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for NU-Link for the Marginal Additional case for the Consumer Transformation scenario. Each different colour represents the change in constraint costs for a particular boundary. It is important to note that the chart shows changes in constraint costs by boundary, i.e. the difference between constraint costs when the project is included and when the project is excluded.

Compared to the First Additional case, the Marginal Additional shows similar levels of additional constraint costs, and an increase in constraint savings in most years. This is because the Marginal Additional case has all of the W3 interconnector and OHA pilot projects included in the supply/demand background, enabling the model to minimise total constraint costs by taking balancing actions across the whole GB for a wider range of solutions.

The figure also shows that the high constraint savings seen in 2031 in the First Additional case are not present, suggesting that the inclusion of all the other W3 interconnectors and OHA pilot project means that the model is able to achieve a different solution which no longer results in such a significant saving when NU-Link is included.

In general, for the Marginal Additional case, NU-Link increases constraint costs on several northern boundaries but relieves congestion on some midlands boundaries. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

PV system operation

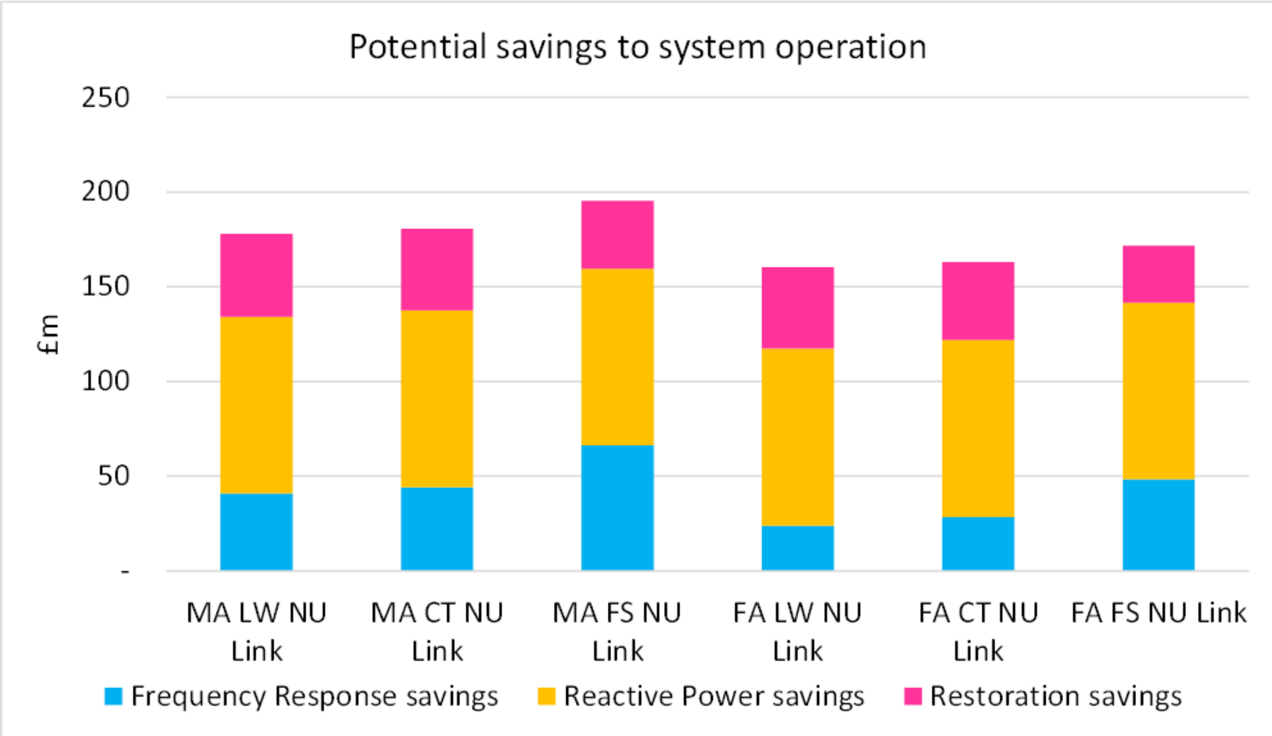

Figure 130: PV potential system operability savings for NU-Link, Present Value 25-year, real 2022, £m.

The above figure shows the potential savings for frequency response, reactive power and restoration services in present value (25 year, 2022 £m) for NU-Link for Leading the Way, Consumer Transformation and Falling Short for both the Marginal Additional and First Additional cases. There is considerable uncertainty around forecasting potential system operability benefits over a 25-year time horizon, but the figure shows that there is potentially significant savings in frequency response, reactive power and restoration services.

There is little variation across the three scenarios and also across the First Additional and Marginal Additional cases. This is because the potential system operability savings from the services provided by NU-Link are less sensitive to flows across the interconnector, whereas the constraint cost impact is highly dependent on the scale and direction of flows across the project.

RES curtailment avoided

Figure 131: Annual RES curtailment avoided for NU-Link for the First Additional case.

The above figure shows the renewable energy supply (RES) curtailment avoided on an annual basis for Leading the Way, Consumer Transformation and Falling Short for the First Additional case. Note that beyond 2042, the results are an average of the years 2040, 2041 and 2042, as our detailed modelling with FES22 only extends out to 2042. The figure shows a spike in RES curtailment avoided in Consumer Transformation for 2031: this coincides with the large constraint saving seen across two boundaries for that year. The figure shows that the level of annual RES curtailment avoided when NU-Link is included is approximately between 1TWh and 3TWh, which equates to approximately between 2.7GWh and 8.2GWh per day.

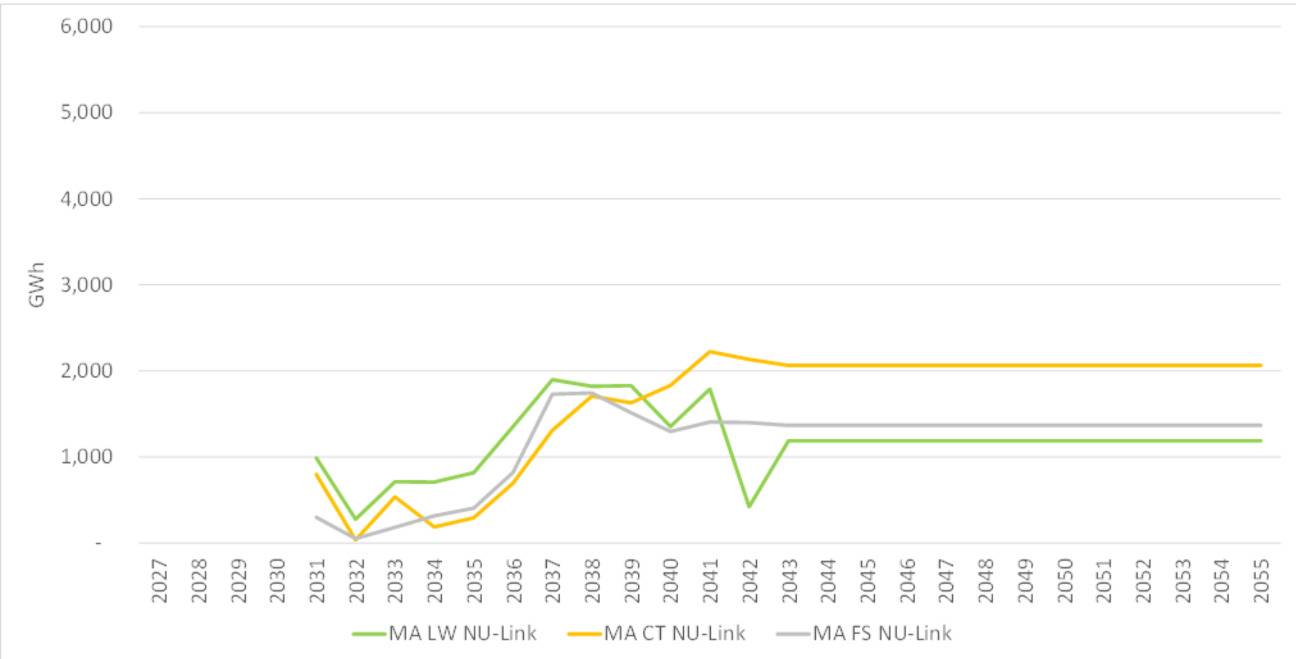

Figure 132: Annual RES curtailment avoided for NU-Link for the Marginal Additional case.

The above figure shows the renewable energy supply (RES) curtailment avoided on an annual basis for Leading the Way, Consumer Transformation and Falling Short for the Marginal Additional case. Note that beyond 2042, the results are an average of the years 2040, 2041 and 2042, as our detailed modelling with FES22 only extends out to 2042. The figure shows that the level of annual RES curtailment avoided when NU-Link is included is approximately between 0.5TWh and 2TWh, which equates to approximately between 1.4GWh and 5.5GWh per day.

18. Tarchon

Tarchon is a W3 interconnector project. It has a capacity of 1.4GW and connects to Germany.

PV constraint costs

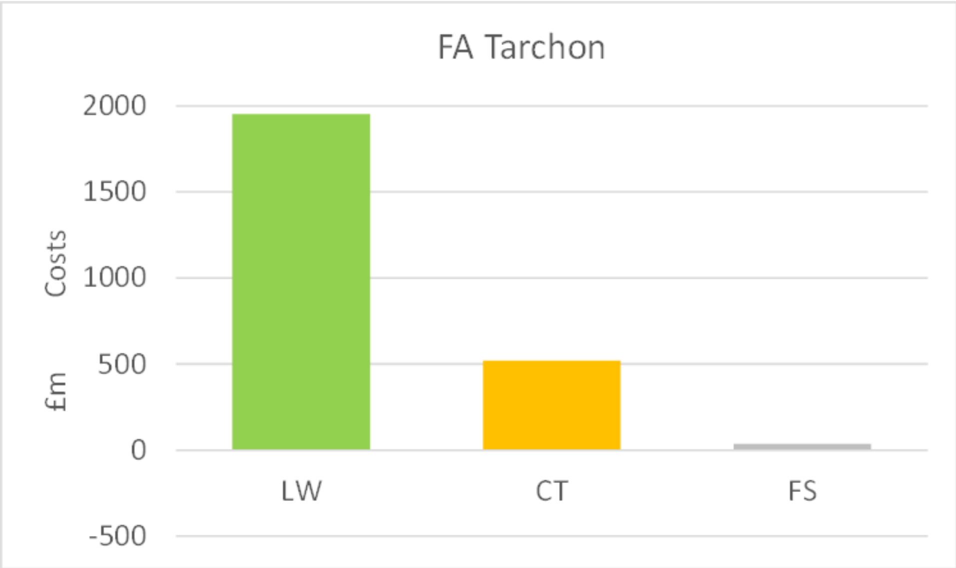

Figure 133: PV additional constraint costs due to Tarchon for the First Additional case, Present Value 25-year, real 2022, £m

The above figure shows the additional constraint costs with the inclusion of Tarchon for the FA case. In the Leading the Way (LW) scenario constraint costs are increased by £1.95bn, in Consumer Transformation (CT) by £0.52bn and in the Falling Short (FS) scenario by £0.04bn.

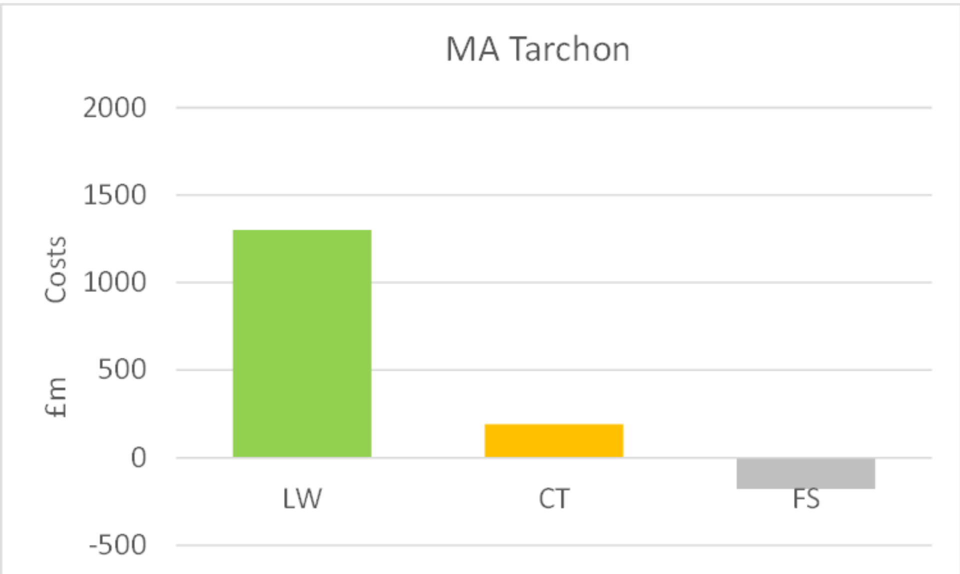

Figure 134: PV additional constraint costs due to Tarchon for the Marginal Additional case, Present Value 25-year, real 2022, £m.

The above figure shows the additional constraint costs with the inclusion of Tarchon for the MA case. Additional constraint costs are significantly lower than in the FA case. This is because the inclusion of the other OHA and Window 3 projects within the supply demand mix reduces the impact of any one interconnector on constraint costs. In the Leading the Way scenario (LW) constraint costs are increased by £1.3bn, in Consumer Transformation (CT) by £0.19bn and in the Falling Short (FS) scenario there is a constraint saving of £0.18bn.

Annual constraint costs

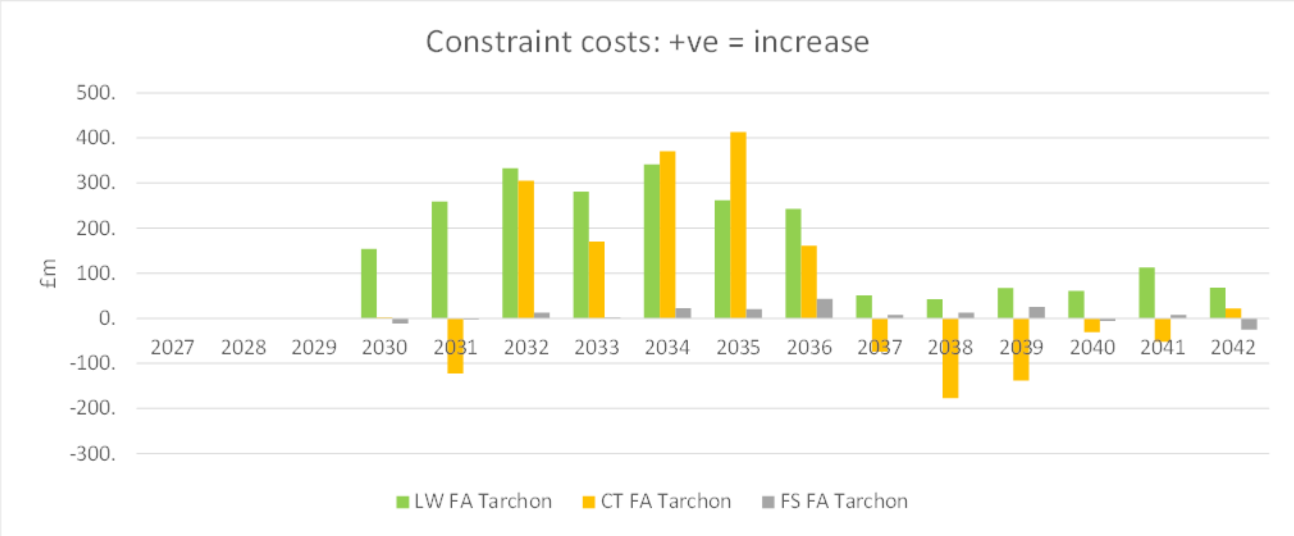

Figure 135: Additional annual constraint costs due to Tarchon for the First Additional case.

The above figure shows that for the First Additional case, Tarchon results in an increase in constraint costs of approximately £150m to £350m (undiscounted) in CT and LW in the years from 2032 to 2035. Thereafter constraint costs fall considerably in LW and constraint savings are seen in CT. In FS constraint costs are very low, with constraint costs below £50m and small savings in some years.

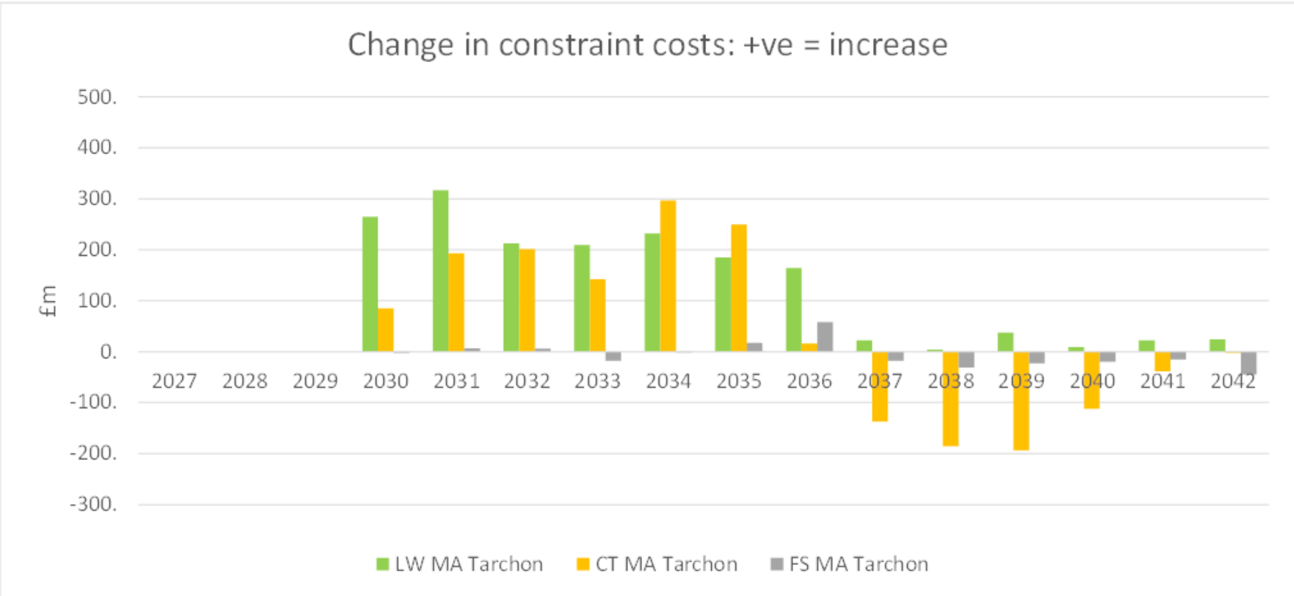

Figure 136: Additional annual constraint costs due to Tarchon for the Marginal Additional case.

The above figure shows that for the Marginal Additional case, Tarchon results in an increase in constraint costs of approximately £100m to £300m (undiscounted) in CT and LW in the years from 2032 to 2035. Thereafter constraint costs fall considerably to very low levels in LW and constraint savings of nearly £200m are seen in several years in CT. In FS constraint costs are very low, with constraint costs below £50m and small savings of up to £50m seen in many of the later years.

Annual import and export flows for dispatch and redispatch

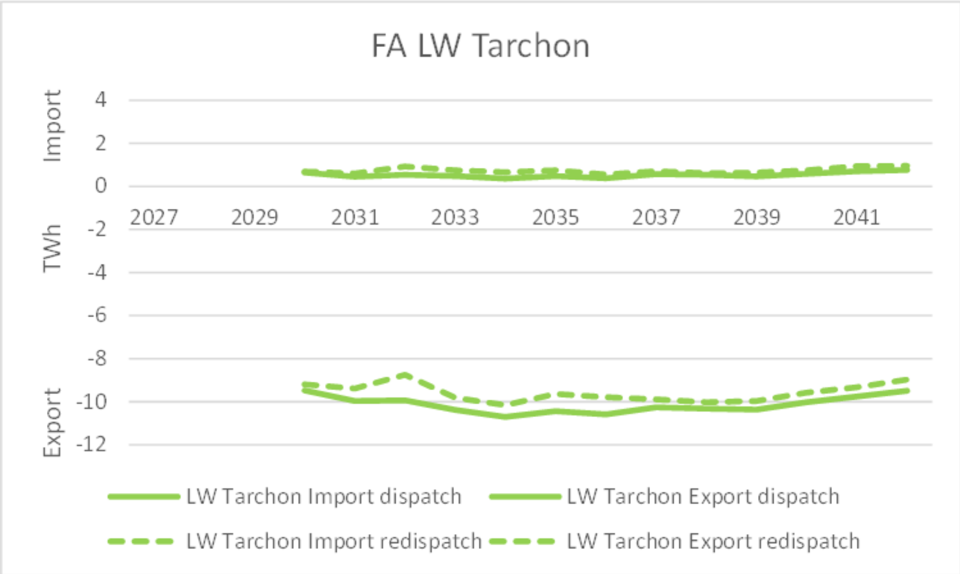

Figure 137: Annual import and export flows for Tarchon in the FA case for Leading the Way.

The above figure shows Tarchon has high exports and very low imports in the dispatch for Leading the Way for the First Additional case. The redispatch shows a small reduction in exports and a very small increase in imports.

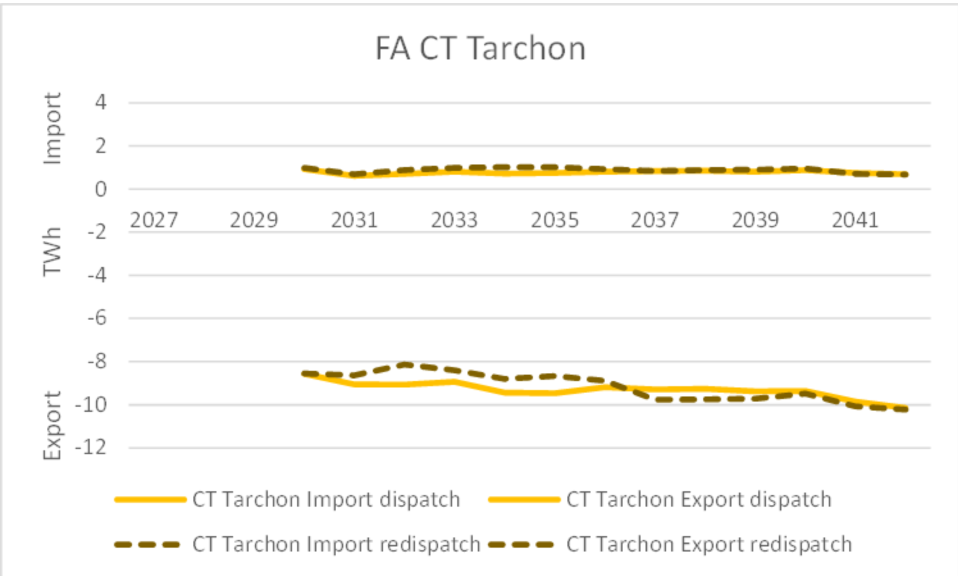

Figure 138: Annual import and export flows for Tarchon in the FA case for Consumer Transformation.

The above figure shows Tarchon has high exports and very low imports in the dispatch for Consumer Transformation for the First Additional case. The redispatch shows a small reduction in exports between 2031 and 2036 and very little change in imports.

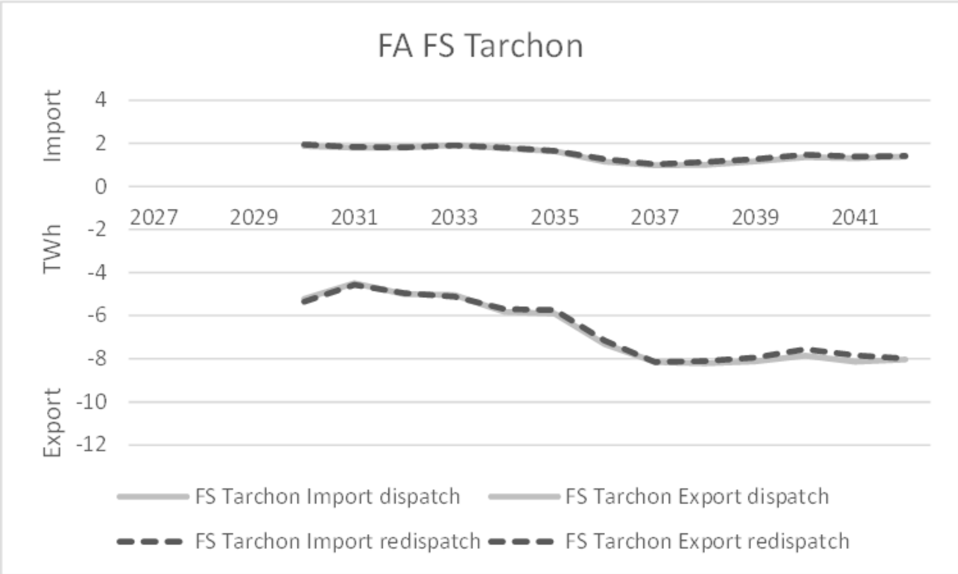

Figure 139: Annual import and export flows for Tarchon in the FA case for Falling Short.

The above figure shows that for the First Additional case Tarchon has increasing levels of exports over the forecast period up to 2037 and low levels of imports in the dispatch for Falling Short. The redispatch shows very little change in imports or exports.

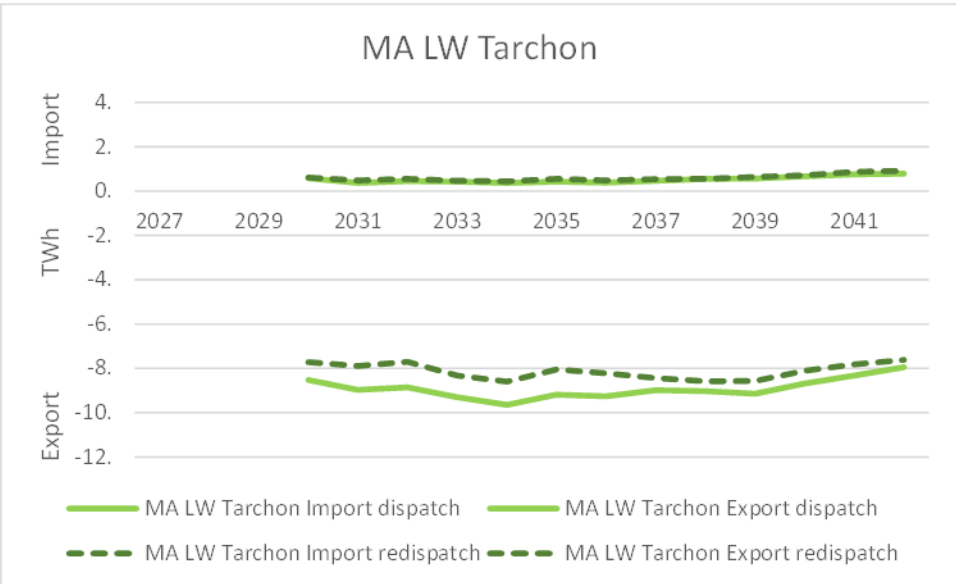

Figure 140: Annual import and export flows for Tarchon in the MA case for Leading the Way.

The above figure shows that for the Marginal Additional case, Tarchon has high exports, but slightly lower than in the First Additional case, and very low imports in the dispatch, similar to those shown in the First Additional case for Leading the Way. The redispatch shows some reduction in exports, especially in the early years and virtually no change in imports.

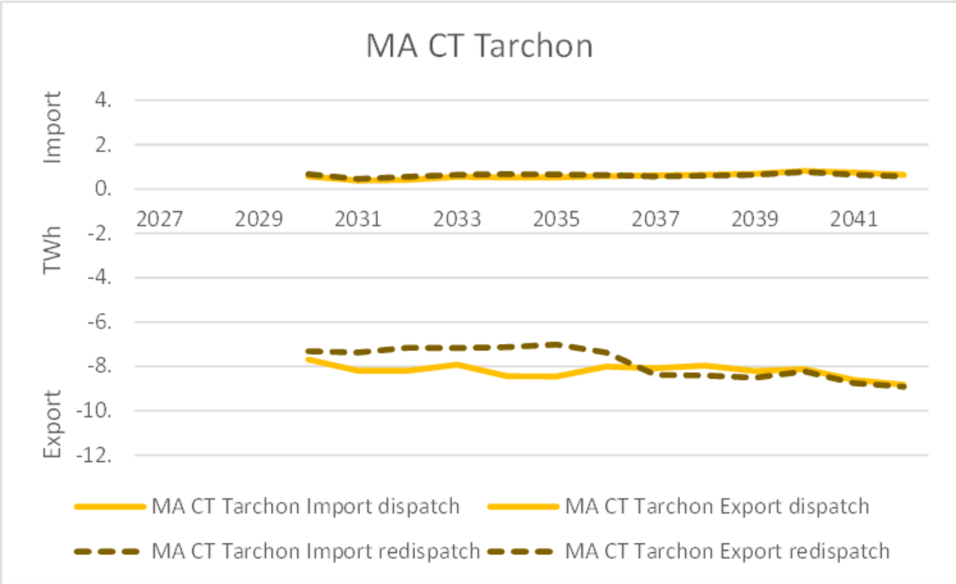

Figure 141: Annual import and export flows for Tarchon in the MA case for Consumer Transformation.

The above figure shows that for the Marginal Additional case, Tarchon has high exports, but slightly lower than in the First Additional case, and very low imports in the dispatch, slightly lower than those shown in the First Additional case for Consumer Transformation. The redispatch shows some reductions in exports, between 2030 and 2036 and virtually no change in imports.

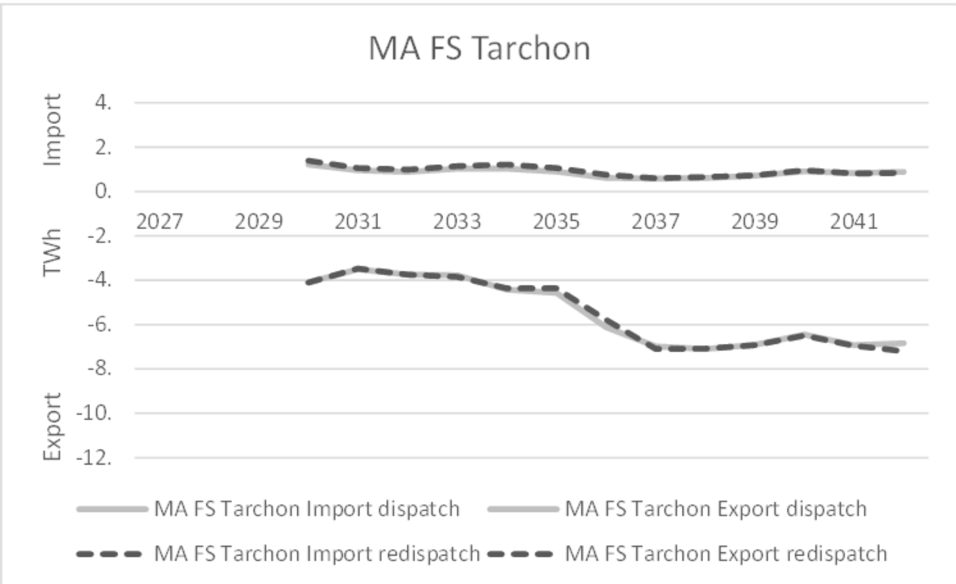

Figure 142: Annual import and export flows for Tarchon in the MA case for Falling Short.

The above figure shows that for the Marginal Additional case, Tarchon has increasing exports, similar to the levels in the First Additional case, and low imports in the dispatch, slightly lower than those seen in the First Additional case for Falling Short. The redispatch shows very little change in flows for imports or exports.

Change in constraint costs by boundary

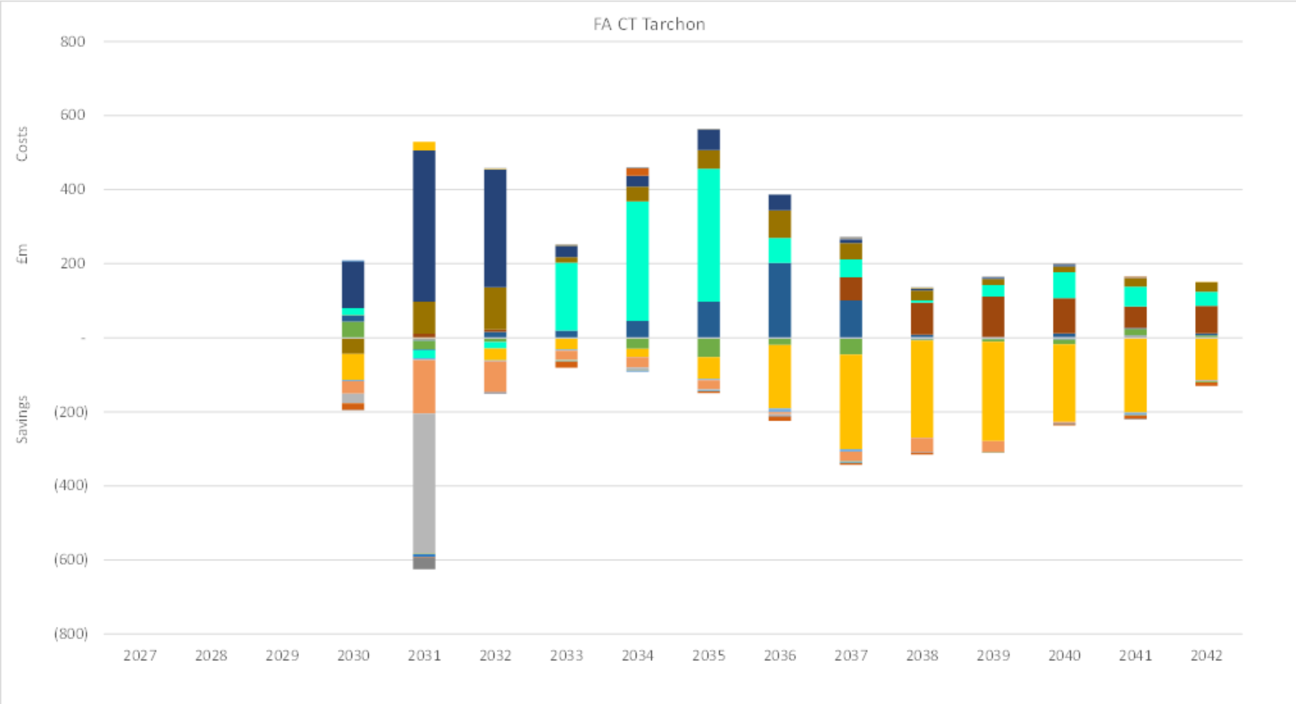

Figure 143: Change in constraint costs by boundary for Tarchon for the FA case for Consumer Transformation.

The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for Tarchon for the First Additional case for the Consumer Transformation scenario. Each different colour represents the change in constraint costs for a particular boundary. It is important to note that the chart shows changes in constraint costs by boundary, i.e. the difference between constraint costs when the project is included and when the project is excluded.

The figure shows that Tarchon increases constraint costs on certain boundaries but also reduces constraint costs on others. Whether the impact is an increase in constraint costs or a reduction in constraint costs for a particular boundary, changes from year to year. The size of change in constraint costs by boundary can also vary significantly from year to year. This is shown clearly in the years 2030 to 2032. The figure also shows that the specific boundaries that have the greatest impact on the total change in constraint costs can vary from year to year. These factors are a result of the changes in demand, supply and network capability over time.

In general, Tarchon increases constraint costs on various midlands and northern boundaries but relieves congestion on various other boundaries. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

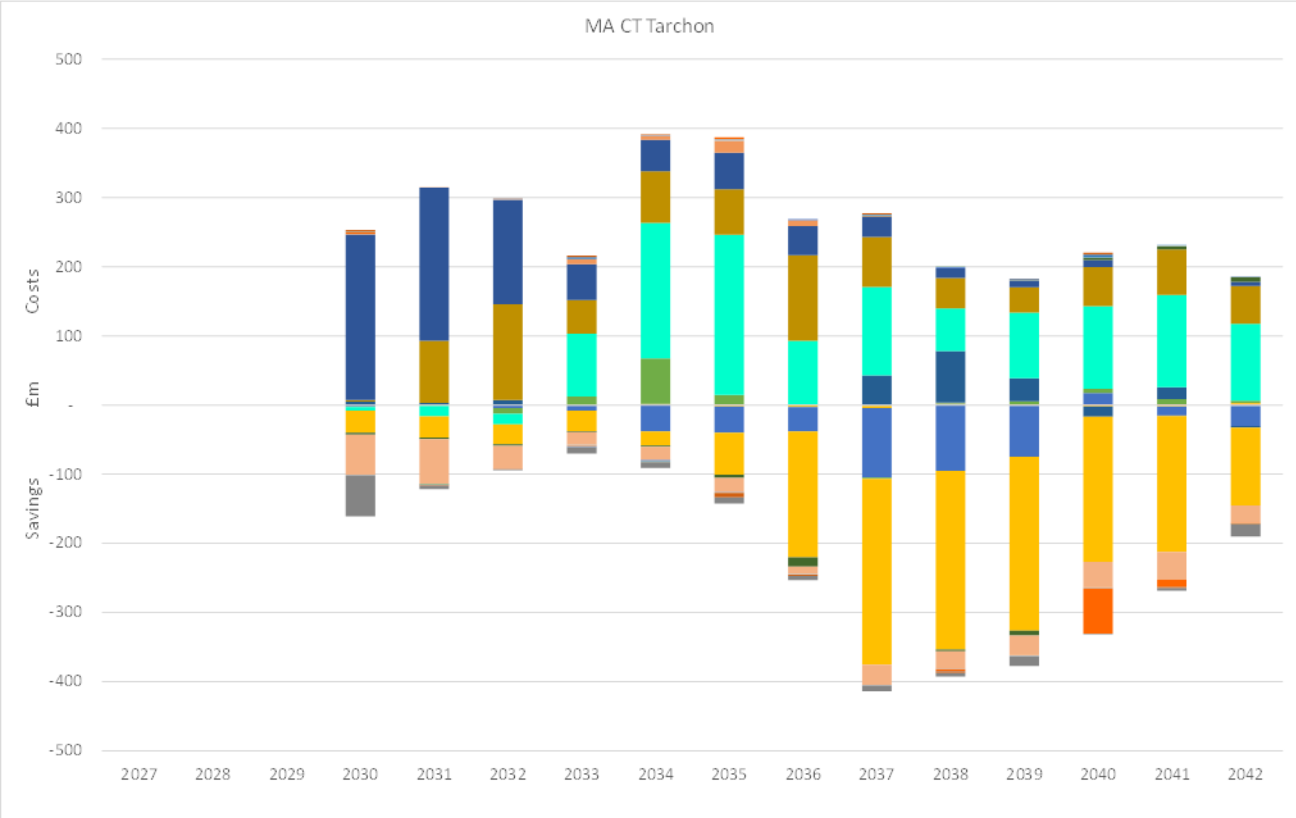

Figure 144: Change in constraint costs by boundary for Tarchon for the MA case for Consumer Transformation.

The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for Tarchon for the Marginal Additional case for the Consumer Transformation scenario. Each different colour represents the change in constraint costs for a particular boundary. It is important to note that the chart shows changes in constraint costs by boundary, i.e. the difference between constraint costs when the project is included and when the project is excluded.

Compared to the First Additional case, the Marginal Additional shows an overall reduction in additional constraint costs each year, and an increase in constraint savings for each year. This is because the Marginal Additional case has all of the W3 interconnector and OHA pilot projects included in the supply/demand background, enabling the model to minimise total constraint costs by taking balancing actions across the whole GB network for a wider range of solutions.

In general, for the Marginal Additional case, Tarchon increases constraint costs on several northern and midland boundaries but relieves congestion on a range of other boundaries. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

PV system operation

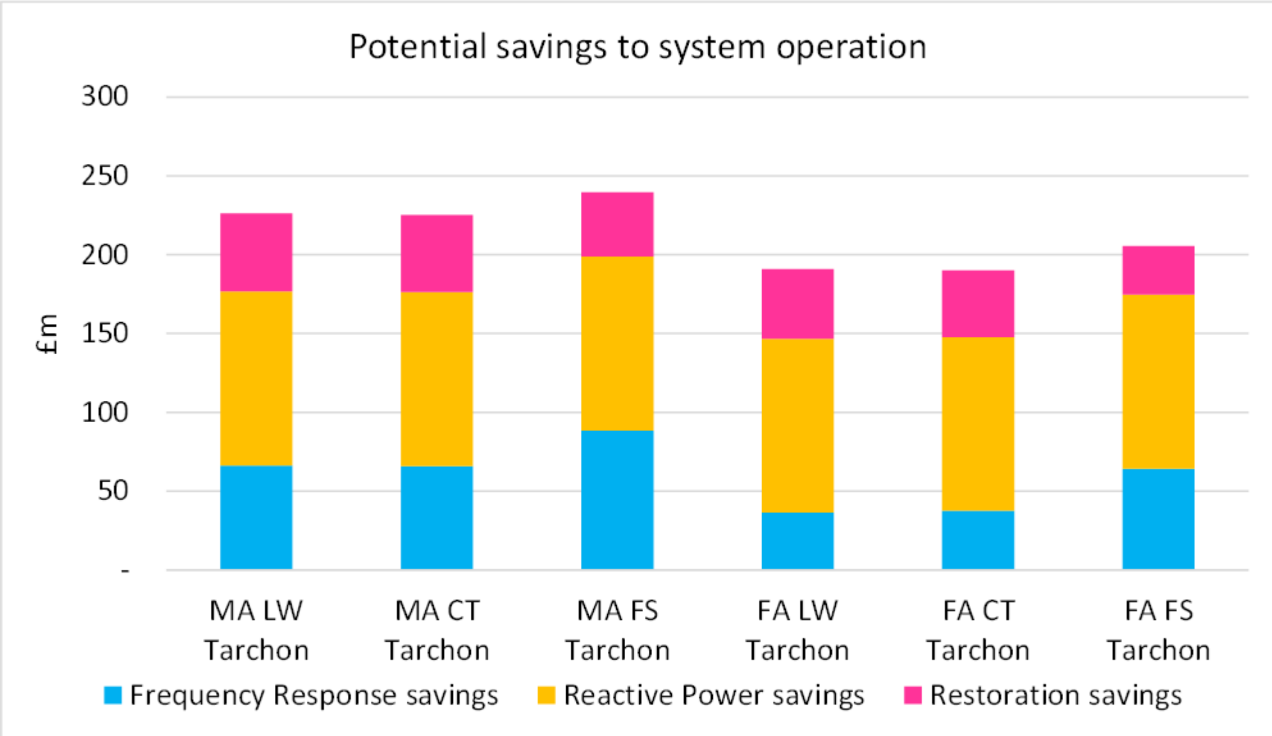

Figure 145: PV potential system operability savings for Tarchon, Present Value 25-year, real 2022, £m.

The above figure shows the potential savings for frequency response, reactive power and restoration services in present value (25 year, 2022 £m) for Tarchon for Leading the Way, Consumer Transformation and Falling Short for both the Marginal Additional and First Additional cases. There is considerable uncertainty around forecasting potential system operability benefits over a 25-year time horizon, but the figure shows that there is potentially significant savings in frequency response, reactive power and restoration services.

There is little variation across the three scenarios and also across the First Additional and Marginal Additional cases. This is because the potential system operability savings from the services provided by Tarchon are less sensitive to flows across the interconnector, whereas the constraint cost impact is highly dependent on the scale and direction of flows across the project.

RES curtailment avoided

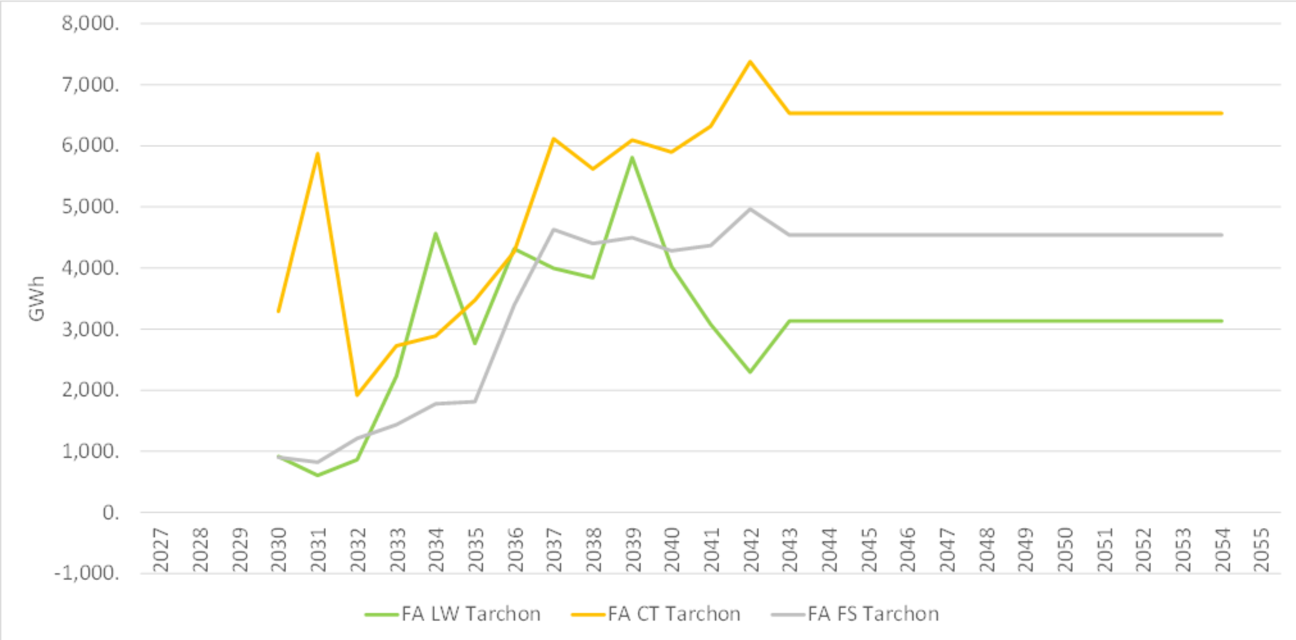

Figure 146: Annual RES curtailment avoided for Tarchon for the First Additional case.

The above figure shows the renewable energy supply (RES) curtailment avoided on an annual basis for Leading the Way, Consumer Transformation and Falling Short for the First Additional case. Note that beyond 2042, the results are an average of the years 2040, 2041 and 2042, as our detailed modelling with FES22 only extends out to 2042. The figure shows that the level of annual RES curtailment avoided when Tarchon is included is approximately between 3TWh and 6.5TWh, which equates to approximately between 8.2GWh and 17.8GWh per day. The figure shows that that the final three years modelled in BID3 (2040 to 2042), which are used to extrapolate the later years, are particularly high for the Consumer Transformation scenario.

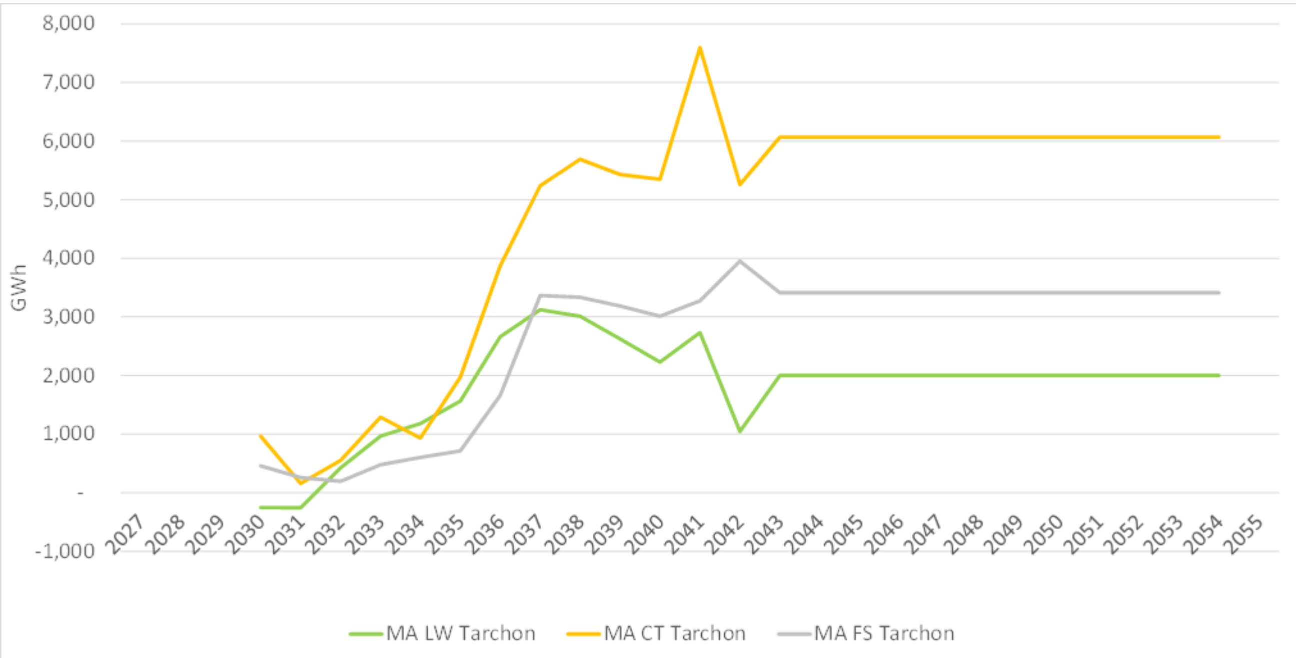

Figure 147: Annual RES curtailment avoided for Tarchon for the Marginal Additional case.

The above figure shows the renewable energy supply (RES) curtailment avoided on an annual basis for Leading the Way, Consumer Transformation and Falling Short for the Marginal Additional case. Note that beyond 2042, the results are an average of the years 2040, 2041 and 2042, as our detailed modelling with FES22 only extends out to 2042. The figure shows that the level of annual RES curtailment avoided when Tarchon is included is approximately between 1TWh and 6TWh, which equates to approximately between 2.7GWh and 16.4GWh per day. The figure shows that that the final three years modelled in BID3 (2040 to 2042), which are used to extrapolate the later years, are particularly high for the Consumer Transformation scenario.

ESO