energy storage IRELAND

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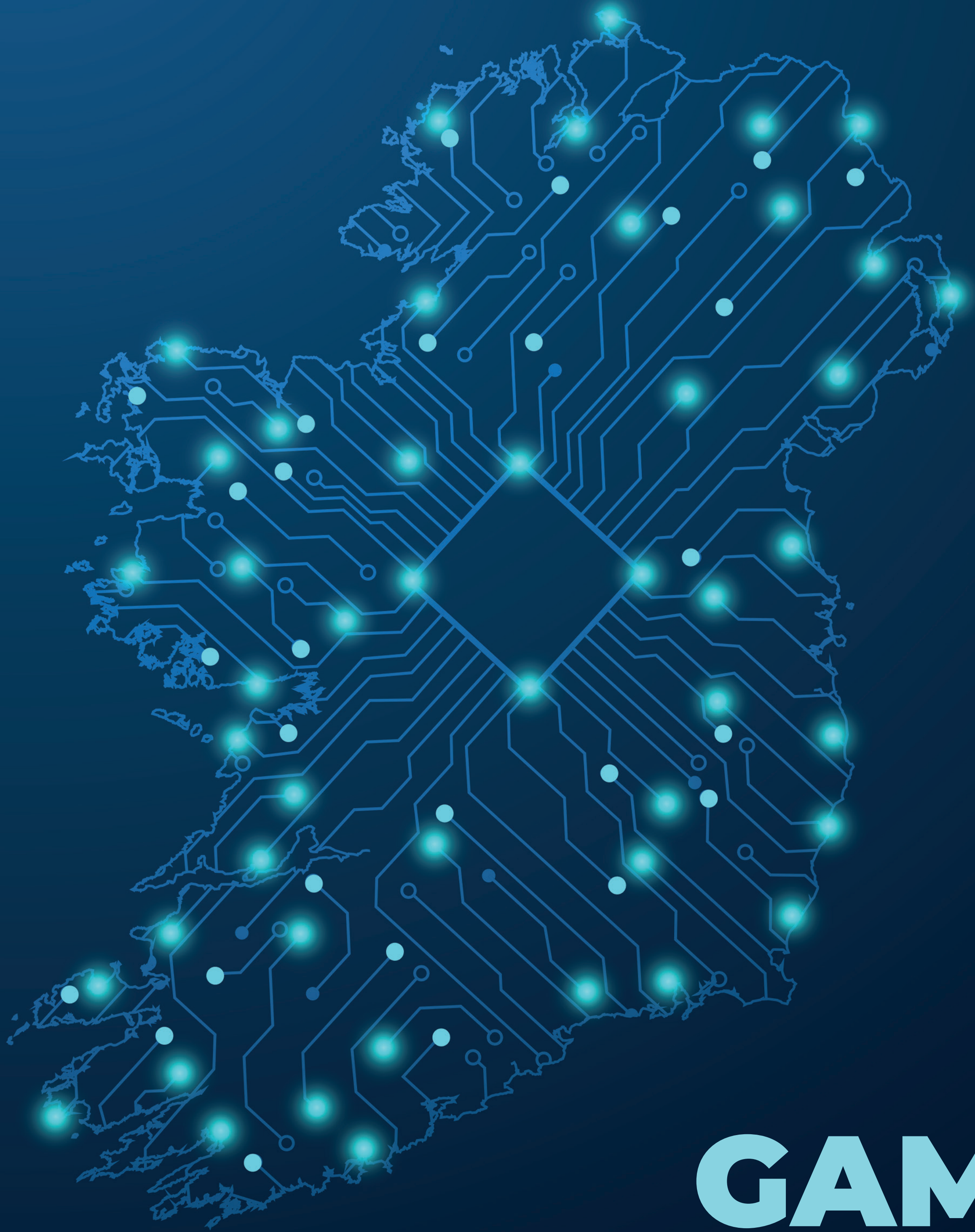

GAME CHANGER

How Energy Storage is the key to a **Secure, Sustainable, Clean Energy Future** in Ireland

MAY **2022**

Version History

Version	Date	Description	Prepared by	Approved by
v4_0	26/05/2022	Finalised issue	Alec Granville-Willett	Mark Turner

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Commissioned by Energy Storage Ireland

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Foreword from Energy Storage Ireland

Everything has changed.

The need to decarbonise our energy supply is the greatest challenge humanity faces but since the start of this year we have faced a new, different, and growing, energy crisis.

The invasion of Ukraine and our dependency on imported fossil fuels means Irish electricity consumers have faced dizzying increases in their bills and the worst may be yet to come.

We must fundamentally change the structure of our energy system.

We need a Game Changer.

Everyone who lives in Ireland is entitled to a secure supply of electricity at a price they can afford and, perhaps most importantly, producing as few CO_2 emissions as possible.

Energy storage can ensure a secure and sustainable supply of clean electricity to Irish homes and businesses, while cutting the cost of electricity for consumers and reducing our CO_2 emissions.

It must be put at the heart of any response in Ireland and Northern Ireland to the current energy crisis and our longer-term decarbonisation targets.

In recent years industry has successfully deployed short-duration lithium-ion battery storage in the All-island market with nearly 500 MW of grid-scale battery capacity operating today.

These battery systems respond in milli-seconds to keep our power system stable, they reduce our reliance on fossil fuel-fired back-up, they help to keep your lights on. Every day.

We have proven that, with the right policies in place, our industry can – and will again – deliver. But in the face of multiple energy crises, we need to do more, faster.

This report shows the enormous benefits of growing out our energy storage capability to fully harness our renewable energy resources and replace expensive, polluting, fossil fuels.

We must focus on delivering proven, quick to deploy, energy storage technologies that can help address Ireland's need for a secure supply of power.

At the same time, we must also start to develop new policies and systems to support the latest energy storage technologies that can help achieve even deeper decarbonisation of the electricity sector.

Our industry is ready to deliver this. We have the talent, the technology, the expertise, and a significant pipeline of projects.

We need a coordinated and collaborative approach with policy makers to get this right, to replace our fossil fuel-fired back-up with a cleaner, cheaper, alternative.

This requires the active support of governments in Ireland and Northern Ireland, and other key stakeholders such as the Regulatory Authorities and System Operators.

There will be challenges, but the reward for success is a more secure energy system, lower bills, and fewer CO_2 emissions.

Everything has changed.

Together, we can change it again.

Bobby Smith,

Head of Energy Storage Ireland

Executive Summary

In this study we have set out to determine the benefits of deploying energy storage in Ireland and Northern Ireland, beyond the provision of zero-carbon system services by battery technologies, the benefits of which were evaluated in our *Store, Respond and Save* study of December 2019.

Key findings

- By participating in the Irish **day-ahead energy market**, energy storage can **reduce day-ahead carbon emissions by 50%** by using long-duration storage technologies. This makes a material contribution to meeting ambitious 2030 power sector decarbonisation goals.
- **Strategic deployment** of energy storage in transmission constrained regions of the network **reduces the dispatch-down of renewable generation** from constraints without the need for network reinforcement, unlocking **additional carbon savings**.
- By contributing to **security of supply**, helping to **support renewable capacity**, and **displacing fossil fuels** in the balancing market, energy storage can deliver a **net saving to end consumers in Ireland of up to €85m per year**.
- These benefits are **additional** to the carbon, renewable curtailment, and end consumer savings offered by energy storage through the **provision of zero-carbon system services**.
- Energy storage helps the integration of renewables at all stages by ensuring that generation is not wasted; **reducing oversupply by up to 60%**, **constraint volumes by up to 90%, and curtailment by 100%**.

Our study

Energy storage encompasses a broad range of technologies including chemical, electrical, thermal, electrochemical, and mechanical storage. Each of these technologies has distinct characteristics and capabilities, such as speed of response, efficiency, and storage capacity, which means that they can provide a variety of valuable services to the Irish all-island power system. We have used our in-house power market modelling capability to analyse a series of portfolios of energy storage capacities and durations, though we have remained technology-agnostic across our two phases of study:

- We first considered the system-level benefits unlocked by the deployment of energy storage from participation in the day-ahead power market in terms of lower CO_2 emissions, security of supply, and end consumer savings in 2030.
- We then analysed the strategic deployment of energy storage capacity in regions of the network with transmission constraints, using County Donegal as a case study, to determine the further carbon reductions and end consumer savings offered by maximising renewable generation in these areas.

Both phases consider a decarbonised 2030 power sector, with the renewable capacity targets of the *Climate Action Plan 2021* in Ireland (8.2 GW of onshore wind, 5 GW of offshore wind, and 2.5 GW of solar PV) and the Accelerated Ambition scenario of the *SONI TESNI 2020* in Northern Ireland (2,540 MW of onshore wind, 500 MW of offshore wind, and 1,170 MW of solar PV). Zero-carbon system services, provided by technologies such as synchronous condensers and short-duration batteries, allow the system to operate without re-dispatch of plant to maintain DS3 limits.

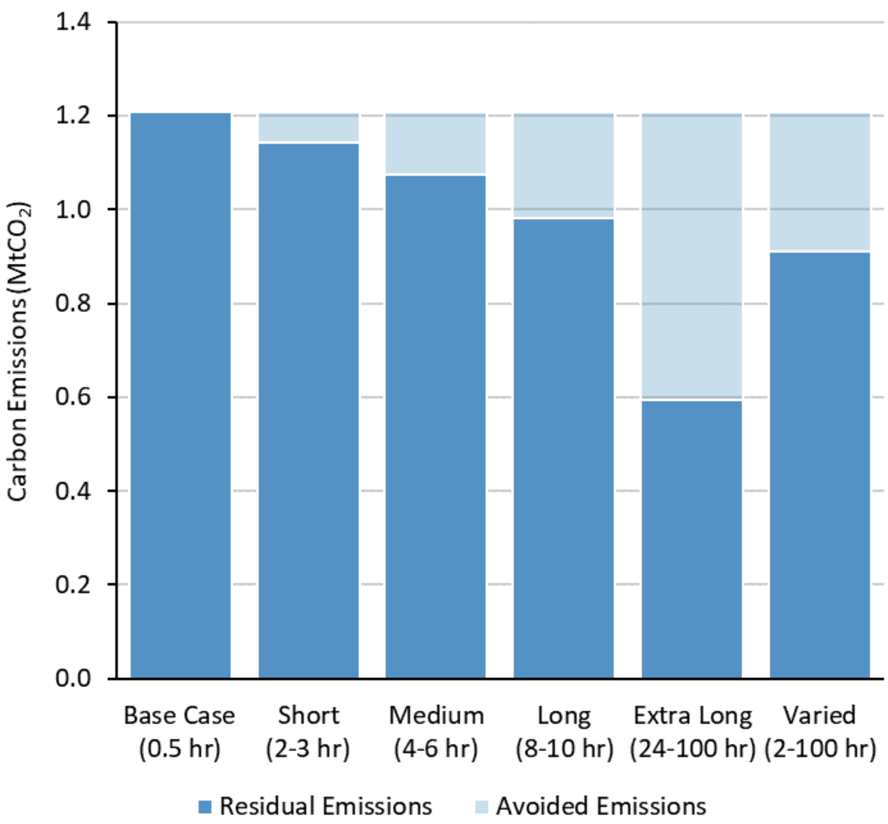
System-level benefits of energy storage

Table 1 below details the installed all-island energy storage assumptions for each scenario, with Figure 1 presenting the resulting emissions from the Irish power sector.

Table 1: All-island energy storage capacity and duration assumptions by scenario (columns)

I-SEM Storage Assumptions	Units	Short	Medium	Long	Extra Long	Varied
I-SEM Storage						
0.5-hour (DS3-only)	*MW*	700	700	700	700	700
2-hour	*MW*	1,000	0	0	0	250
3-hour	*MW*	1,000	0	0	0	250
4-hour	*MW*	0	1,000	0	0	250
6-hour	*MW*	0	1,000	0	0	250
8-hour	*MW*	0	0	1,000	0	250
10-hour	*MW*	0	0	1,000	0	250
24-hour	*MW*	0	0	0	1,000	250
100-hour	*MW*	0	0	0	1,000	250

Figure 1: Irish power sector CO_2 emissions (excluding re-dispatch for transmission constraints)

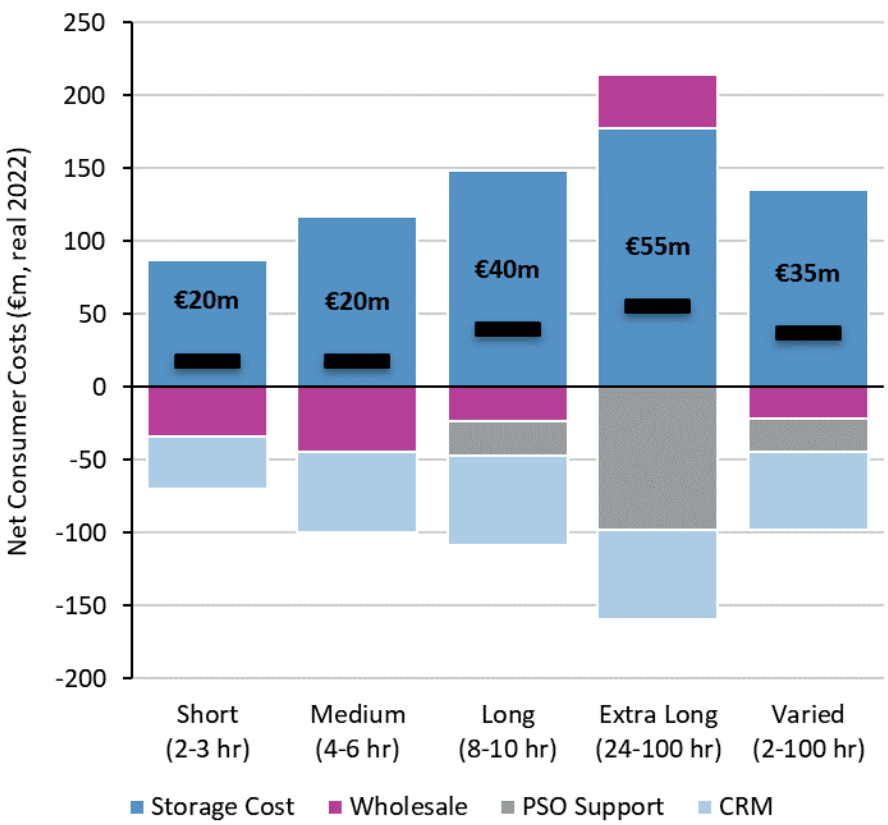


The emissions presented in Figure 1 correspond to those that would result from the day-ahead market schedule of plant, before any re-dispatch to account for transmission constraints.

We compared each storage scenario against the Base Case, which includes 700 MW of dedicated system service-providing 0.5-hour duration storage, but no further storage deployment. Annual Irish power sector emissions in the Base Case, around 1.2 $MtCO_2$, are significantly below those seen historically due to the assumed additional renewable capacity build and zero-carbon provision of system services. By participating in the day-ahead market, energy storage is able to reduce these residual emissions significantly. Our analysis shows that a portfolio of 24- and 100-hour duration storage can reduce emissions by over 50% in the Extra Long-Duration scenario. Storage achieves this by absorbing excess low cost and zero-carbon renewable energy in hours of oversupply, and releasing it when it is most needed. This enables the integration of a greater capacity of renewables, relieves reliance on fossil fuels, and reduces end consumer costs.

In Figure 2 we present the results of our system-level cost-benefit analysis for 2030 for each storage scenario, relative to the Base Case. Each net cost is shown as a positive value, with net benefits presented as negative. The annuitized cost of the additional storage assets is substantially offset in each scenario by the benefits of lower peak wholesale prices, reduced costs to support renewable capacity via the PSO levy, and capacity market savings driven by the security of supply contribution of storage. The energy storage portfolio modelled in the Extra Long-Duration scenario, which reduced residual day-ahead market CO_2 emissions by over 50%, incurs a net cost to end consumers of around €55m in 2030. However, the benefits presented in this phase do not include those conferred by strategic deployment of storage in constrained areas of the network, which we have also explored.

Figure 2: End consumer system-level cost-benefit analysis for Ireland in 2030



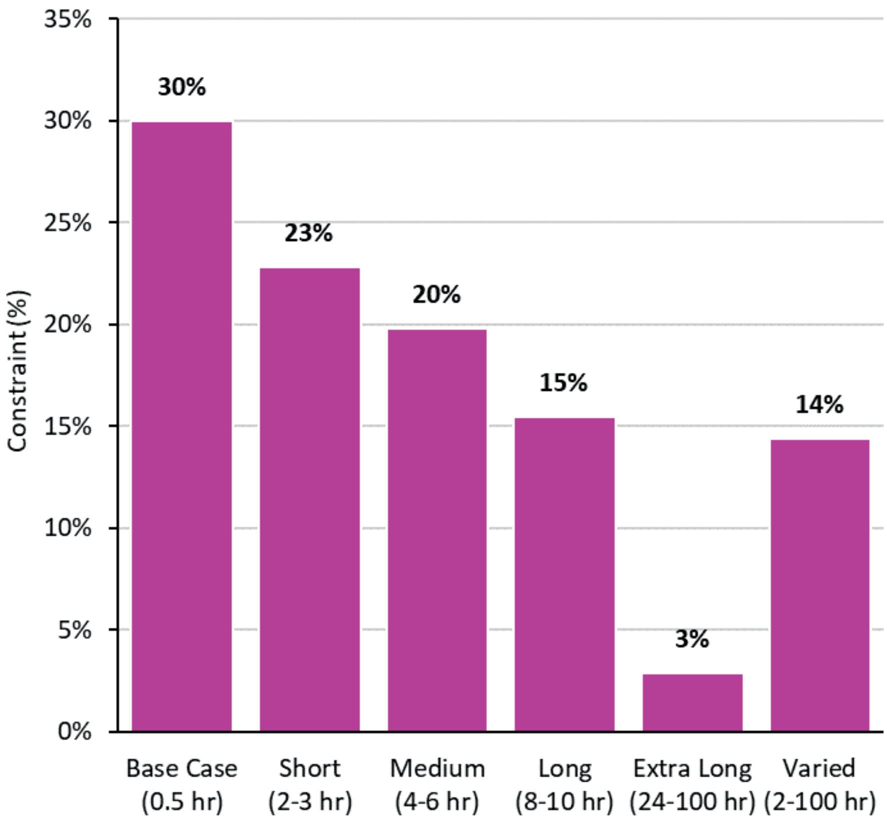
Local constraint benefits of energy storage

In the second phase of our study we modelled the constrained transmission capacity between County Donegal and the rest of the all-island network to determine the impact of strategic locational deployment of energy storage on renewable constraint in the county, and the further carbon savings unlocked. We present our main assumptions in Table 2 below. We analysed each scenario from the previous phase, with 400 MW of storage capacity of varying durations assumed in County Donegal. Figure 3 presents the resulting local renewable constraint in the Base Case and each scenario.

Table 2: Key County Donegal scenario assumptions in this phase of study

County Donegal Key Assumptions	Units	Donegal
Installed Generation Capacity		
Onshore wind	*MW*	930
Hydro	*MW*	70
N-1 Transmission Capacity		
Summer rating	*MVA*	360
Autumn rating	*MVA*	380
Winter rating	*MVA*	400

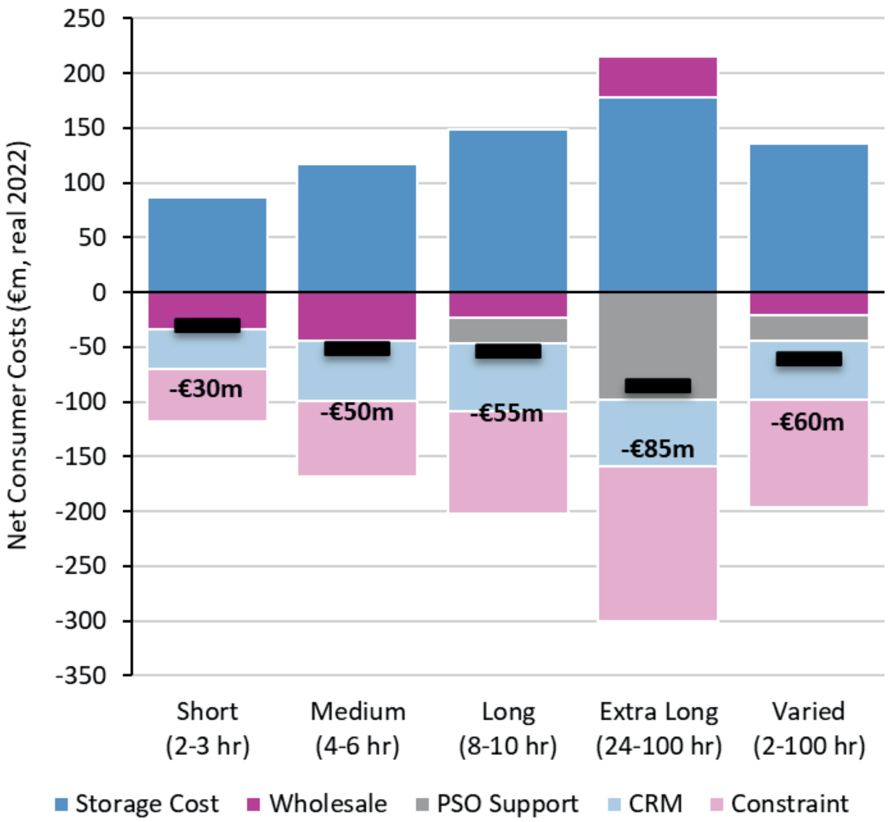
Figure 3: Renewable constraint volumes in County Donegal



In the Base Case, without energy storage in County Donegal, the build-out of onshore wind capacity results in constraint of around 30%, with the turned-down energy being lost due to limitations of the transmission network. By charging during hours of constraint, in which the transmission capacity cannot support the available renewable generation in the county and export it to the wider network, storage assets are able to discharge this energy in hours of low renewable output. **Our analysis shows that 200 MW of 24-hour and 200 MW of 100-hour duration storage can reduce constraint in the county by up to 90%, releasing 470 GWh of recovered low cost zero-carbon electricity.**

This energy acts to displace fossil fuel-fired generation, reducing the CO_2 emissions associated with the re-dispatch of plant in the Balancing Mechanism. In the Extra Long-Duration scenario, a total of 150 ktCO_2 can be displaced in 2030 by the storage in County Donegal. Under the illustrative assumption that this saving 'per MW' is representative of the overall storage fleet, around 620 ktCO_2 could be displaced by the strategic deployment of the storage portfolio on the network. The associated fuel and carbon cost savings of around €140m in the Extra Long-Duration scenario result in an overall net benefit of energy storage of €85m in ROI in 2030 as presented in Figure 4 below.

Figure 4: ROI end consumer cost-benefit analysis for 2030 including savings from lower constraint



Recommendations from Energy Storage Ireland

Given the substantial decarbonisation benefits and end consumer savings unlocked by energy storage demonstrated by Baringa in this study, particularly those of longer storage durations, an appropriate policy landscape designed to enable their build-out is vital. In response to Baringa's findings, Energy Storage Ireland highlights the current key barriers to entry for these technologies, and provides a series of recommendations to address them, summarised in Table 3 below.

Table 3: Summary of energy storage policy recommendations

Policy	Recommendation	Key Stakeholders	Timeline
Energy Storage Strategy	Develop a holistic energy storage strategy in Ireland and Northern Ireland that addresses the key barriers for energy storage and sets out a roadmap of actions, stakeholders, and timelines for the sector.	DECC, DfE	Q1 2023
Capacity Remuneration Mechanism	1. Carry out a review of CRM de-rating factors to ensure appropriate consideration of energy storage. 2. Conduct consultation on policy options to reform the CRM for net zero.	CRU, UR	1. Q3 2022 2. Q1 2023
System Services	Develop an enduring system services framework decision that supports existing and new low carbon service providers.	CRU, UR	Q4 2022
Network Solutions	Publish a consultation on options to enable energy storage as a network solution e.g. cap and floor mechanism, locational capacity contracts, congestion products etc.	CRU, UR, EirGrid, SONI	Q1 2023
Network Charging	Review current import and export network charging arrangements for energy storage to ensure full consideration of the system benefits provided by storage assets and remove unnecessary financial barriers.	CRU, UR	Q1 2023
Connection Policy	Develop a long-term connection policy framework that provides a defined connection route for energy storage, and enables storage projects to connect in a timely manner.	CRU, UR	Q3 2022
Market Integration	Allow full participation of energy storage assets in the energy market: 1. Update TSO systems to allow acceptance and relay of negative physical notifications (instructions for import of energy); and 2. Update TSO systems to allow full integration of energy storage into scheduling and dispatch systems for import and export of energy.	EirGrid, SONI	Q2 2023
Hybrid Projects	Remove barriers to hybrid projects: 1. Allow multiple legal entities behind single connection point; 2. Remove over-install cap on MEC; and 3. Allow sharing of MEC between technologies behind a single connection point.	EirGrid, SONI, NIEN, ESBN	Q4 2022

1 Introduction

1.1 Energy storage in Ireland and Northern Ireland

1.1.1 Overview

Ireland's first large scale energy storage facility was the 290 MW pumped hydro storage station at Turlough Hill, which became operational in 1974 and remains active today. More recently the energy storage market has seen rapid deployment of lithium-ion battery energy storage systems (BESS) with the first grid-scale project becoming operational in 2020, and all-island deployment forecasted to reach nearly 800 MW by 2023[1].

BESS deployment in the near-term will predominantly be short-duration batteries, typically 30 minutes in duration[2], used to provide fast-acting frequency response and reserve grid services that can replace the need for fossil fuel-fired generators in the provision of these services, enabling significant reductions in carbon dioxide (CO_2) emissions and end consumer costs as was demonstrated in our *Store, Respond and Save*[3] and *Endgame*[4] reports.

Going forward we expect that the storage market will evolve to provide a wider variety of services, and that the portfolio of storage technologies and capabilities will become more diverse to support Ireland and Northern Ireland's ambitious decarbonisation targets.

However, the Irish and Northern Irish Governments have not set long-term capacity targets for energy storage and so, beyond the deployment of short-duration BESS in the near-term, there is some uncertainty as to the capacity and durations of energy storage that will be needed to support decarbonisation goals. It is also unlikely that the all-island market structures and policies at present are sufficient to drive development of energy storage that will be needed in future.

In this study we have aimed to address these uncertainties by analysing a variety of storage portfolios within a modelled scenario of the 2030 all-island power system (the I-SEM) and quantifying the benefits that energy storage can provide in terms of CO_2 emission reductions, production cost savings, security of supply, renewable oversupply, and alleviation of transmission constraints. We have utilised the same thorough modelling methodology that we have employed in previous studies[5], with our pan-European power market model simulating the hourly plant dispatch in the island of Ireland.

Based on the results of our study, Energy Storage Ireland has sought to address some of the policy uncertainties and provide recommendations that would help facilitate further deployment of energy storage in future to deliver its benefits.

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[1] Energy Storage Ireland pipeline survey data.
[2] The 'duration' of an energy storage asset refers to the length of time that it can continuously discharge, or release energy.
[3] *Store, Respond and Save*
[4] *Endgame*
[5] Detail on previous Baringa reports is given in Appendix C.2.

1.1.2 Ireland's Climate Action Plan

Ireland's *Climate Action Plan*, first published in June 2019[6] and updated in November 2021[7], provides a roadmap for Ireland to achieve a 51% reduction in overall greenhouse gas emissions by 2030, and ultimately to reach net zero emissions by no later than 2050.

For the electricity sector the 2021 plan sets a target to increase the proportion of renewable electricity to 80% by 2030, and to reduce emissions to a range of 2 to 4 million tonnes of CO_2 ($MtCO_2$) by 2030 (a 62-81% decrease from 2018 levels). These targets exceed the ambition of those stated in the 2019 plan; 70% renewable electricity and 4 to 5 $MtCO_2$.

The proposed pathway includes a more rapid build-out of renewable generation capacity (wind and solar power generation technologies) and energy storage than had been proposed previously. Specifically, the Department of the Environment, Climate and Communications (DECC) will develop a storage policy that supports the 2030 targets and aligns with Ireland's renewable gas ambition, security of supply, and policy drivers to encourage deployment of flexible technologies.

1.1.3 Northern Ireland's Energy Strategy

In December 2021, the Department for the Economy published the *Energy Strategy for Northern Ireland – the Path to Net Zero Energy*[8] document. The goal of the strategy is a 100% reduction in energy sector emissions by 2050. To deliver this ambition the strategy aims to deliver a 56% reduction in energy sector emissions by 2030 relative to 1990 levels and sets a target of at least 70% renewable electricity by 2030. This final target was superseded by an 80% renewable electricity ambition in an amendment to the *NI Assembly Climate Change Bill*[9] in March 2022.

The strategy also highlights a high-level action to implement measures around system flexibility services, energy storage, data access, and electromobility. These measures are proposed to support the integration of the elevated levels of renewable generation expected on the system by 2030, an approximate doubling from today's levels.

1.1.4 Shaping our Electricity Future

The *Shaping our Electricity Future Roadmap*[10], a joint publication by the transmission system operators (TSOs), EirGrid and SONI, was released in November 2021. The publication set out the TSOs plans from the perspective of networks, engagement, operations, and the market, to support a secure transition to at least 70% renewable electricity on the grid by 2030.

The roadmap estimates that between 2 and 3 GW of new dispatchable capacity is needed across Ireland and Northern Ireland for a secure transition to 2030 and that this capacity is required to meet demand where renewables are not available. This is proposed to be a balanced portfolio of BESS, demand-side flexibility, interconnection, and renewable gas-ready conventional fossil fuel-fired capacity. The TSOs also note that in the longer-term other storage technologies such as long-duration batteries and new pumped hydro storage assets will play a key role.

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[6] Climate Action Plan 2019
[7] Climate Action Plan 2021
[8] Energy Strategy for Northern Ireland – The Path to Net Zero Energy
[9] NI Assembly Climate Change Bill (Further Consideration Stage)
[10] Shaping our Electricity Future Roadmap

On an all-island basis the TSOs have assumed approximately 2 GW of BESS is deployed by 2030, with 400 MW of this having an average duration of 0.5 hrs, 1,050 MW with an average duration of 2 hrs, and 550 MW with an average duration of 6 hrs.

1.2 Zero-carbon system services

Our *Store, Respond and Save* report, published in December 2019, demonstrated the valuable role that 'zero-carbon' flexible technologies such as BESS, demand-side response, synchronous condensers, and renewable generators could play in the provision of system services – avoiding the need to source them from fossil fuel-fired generators. Our analysis showed that procuring system services from zero-carbon providers could reduce all-island power sector emissions by almost 2 million tonnes of CO_2 per year by 2030. It would also result in significant operational cost savings of €120 million per year by 2030, primarily from avoided fuel and carbon costs, and reduce system-level renewable dispatch-down[11] by 50%.

The analysis underpinning *Store, Respond and Save* was rooted in an Irish power sector compliant with the 70% renewable electricity target first modelled in our *70 by 30*[12] study, and later adopted in the *Climate Action Plan 2019*. Our June 2021 *Endgame* report demonstrated that a more ambitious deployment of zero-carbon system services could enable a 2030 power sector with 80% renewable electricity, and emissions of less than 2 $MtCO_2$. As in the previous study, zero-carbon provision of system services unlocked cost savings to the end consumer; over €250 million in 2030 from avoided dispatch balancing costs in Ireland alone.

The benefits we have evaluated in this study are in addition to those conferred by storage through provision of zero-carbon system services, those being quantified in *Store, Respond and Save*, and *Endgame*. The results of the study show the additional potential benefits that can be delivered from deployment of energy storage of varying capabilities and durations out to 2030, beyond that required for zero-carbon system services.

1.3 Our approach to this study

To quantify the holistic impact of energy storage on the Irish and Northern Irish power sectors, we have conducted two distinct modelling phases. First, we have modelled the day-ahead power market arrangements in I-SEM, both with and without participation of energy storage capacity. A range of storage durations between 2 and 100 hours have been considered across five scenarios. A 'Base Case' has also been modelled, in which enough dedicated DS3[13]-providing short-duration storage is deployed to meet the DS3 limits in I-SEM, with no build of storage beyond this level, or participation of storage in the day-ahead market. All scenarios include this dedicated storage capacity, as well as other technologies capable of providing zero-carbon system services. **The incremental changes to the model outputs between the scenarios and the Base Case have been analysed to determine the benefits offered by energy storage at the system-wide level. This analysis is presented in Section 2.**

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[11] Detail on dispatch-down actions in I-SEM is presented in Appendix A.

[12] *70 by 30*

[13] Delivering a Secure, Sustainable Electricity System (DS3) is EirGrid's holistic programme of changes designed to enable power sector decarbonisation. 'DS3 limits' are requirements that the all-island system must meet in all hours to ensure system stability and security of supply. Market participants can provide 'DS3 services', ancillary products such as reserve, inertia, and reactive power, which are required to maintain the DS3 limits.

We have then modelled the I-SEM with consideration of the transmission capacity between County Donegal in the North-West of Ireland, and the rest of the all-island system. The applied transmission limit acted to increase the level of dispatch-down seen by renewable generators modelled in the county, representative of the level of renewable constraint in the region. The scenarios considered in the system-level phase of study were then re-run with this constraint in place, with a portion of the day-ahead market active storage capacity being apportioned to County Donegal. **The reduction in renewable constraint in the scenarios relative to the Base Case is representative of the benefits conferred by strategic deployment of energy storage behind transmission constraints. This analysis is presented in Section 3.**

The storage deployment scenarios considered across both phases of study are:

- **Short-Duration**: In addition to the storage capacity build in the Base Case, a total of 2 GW of 2- and 3-hour duration storage is commissioned on the all-island system by 2030. This storage capacity is modelled as participating in the day-ahead market, unlike the 0.5-hour duration storage assets.
- **Medium-Duration**: The Base Case storage capacity is complemented by 2 GW of 4- and 6-hour duration storage projects.
- **Long-Duration**: 2 GW of 8- and 10-hour storage capacity is assumed on an all-island basis, in addition to the Base Case assumptions. Storage technologies of this duration would be new to the island of Ireland, exceeding the roughly 5-hour duration of the Turlough Hill pumped hydro storage plant.
- **Extra Long-Duration**: 2 GW of 24- and 100-hour duration storage capacity is deployed on the island, incremental to the Base Case capacity. 100-hour duration storage was previously modelled in the *Endgame* study, in which it proved to be an effective solution in a highly decarbonised Irish power sector.
- **Varied Duration**: A range of storage technologies between 2 and 100 hours in duration is deployed in I-SEM in equal proportion, totalling 2 GW on top of the Base Case capacity.

Each scenario has been evaluated relative to the Base Case:

- **Base Case**: No energy storage capacity is assumed deployed in I-SEM beyond the existing Turlough Hill pumped hydro storage plant, and the 700 MW of dedicated DS3-providing 0.5-hour duration capacity required to meet the all-island operating reserve requirement[14].

All scenarios consider an all-island system compliant with the ambitious renewable capacity targets presented in the *Climate Action Plan 2021* in ROI, and the Accelerated Ambition scenario of SONI's *Tomorrow's Energy Scenarios Northern Ireland (TESNI) 2020*[15] in NI. The DS3 limits of the I-SEM system, such as the System Non-Synchronous Penetration (SNSP) limit and minimum units for system stability (Min Gen) limits, are maintained by a suite of zero-carbon system services in all scenarios. These services are provided by dedicated storage capacity, synchronous condensers, system flexibility, and renewable capacity.

[14] We have assumed that the requirements for primary operating reserve (POR) and secondary operating reserve (SOR) increase from 75% to 100% of the largest infeed by 2030. This would bring them in-line with the current tertiary operating reserve (TOR1 and TOR2) requirements. The largest infeed in all modelled scenarios is the 700 MW Celtic Interconnector.

[15] *SONI Tomorrow's Energy Scenarios Northern Ireland 2020*

Conventional fossil fuel-fired generators do not need to be re-dispatched from their day-ahead positions to provide inertia, this requirement being served by synchronous condensers. The proportion of electricity demand met by renewable sources (RES-E) in Ireland exceeds the 2030 target of 80% in all scenarios, with Northern Ireland's aligned target exceeded as well.

We have nominally modelled the year 2030 for the purposes of scenario assumptions such as commodity and carbon prices, demand, and interconnection to other markets. Each assumption is based on publicly available sources where possible, as well as internal Baringa analysis and market intelligence. All inputs, besides the capacity and duration of storage technologies deployed, are aligned between scenarios within each phase of the study.

The underlying assumptions of the scenarios are presented in this report, along with details of the methodology used, and the results and implications of the study.

The remainder of the report is structured as follows:

- **Section 2** presents the findings of the system-level modelling phase of the study, as well as the key assumptions and methodology underpinning them;
- **Section 3** provides detail of the modelling and results of the County Donegal case study;
- **Section 4** provides commentary around the economic value of energy storage in Ireland;
- **Section 5** presents the key findings of the study;
- **Section 6** details policy recommendations from Energy Storage Ireland based on the conclusions of the study; and
- **Appendix A** to **Appendix C** provide further detail on the scenario assumptions used throughout the study, and an overview of Baringa.

All monetary figures in this report are presented in real 2022 currency.

2 System-level benefits

2.1 Scenario assumptions

2.1.1 Overview of assumptions

Each scenario explored in Section 2 has been modelled using aligned scenario assumptions representative of a nominal 2030 year in which the power sector decarbonisation targets presented in the *Climate Action Plan 2021* and *SONI TESNI 2020* are achieved in the Republic of Ireland (ROI) and Northern Ireland (NI) respectively. Zero-carbon solutions to the all-island DS3 limits have been deployed to enable the extensive deployment of renewable capacity assumed, as was explored in *Endgame*. The key system-level input assumptions are presented in Table 4 below, with jurisdiction-level assumptions detailed in Table 5 below.

Table 4: Key all-island scenario assumptions in the system-level benefit phase of study

All-Island Scenario Assumptions	Units	I-SEM
Commodity & Carbon Prices		
Coal CIF ARA	*$/tonne*	73
Gas NBP	*€/MWh*	25
Oil Brent	*$/bbl*	84
Carbon EUA	*€/tonne*	93
Carbon UKA	*£/tonne*	82
I-SEM DS3 Limits		
SNSP limit	*%*	100%
RoCoF limit	*Hz/s*	1.0
Minimum inertia limit	*MWs*	0
System stability minimum units - ROI	*#*	0
System stability minimum units - NI	*#*	0

Table 5: Key jurisdiction-level scenario assumptions in the system-level benefit phase of study

ROI and NI Scenario Assumptions	Units	ROI	NI
Demand			
Annual demand excluding storage	*GWh*	43,380	10,520
Peak demand	*MW*	7,320	1,780
EV number	#	1,000,000	371,700
HP number	#	600,000	158,500
Installed Generation Capacity			
Onshore wind	*MW*	8,200	2,540
Offshore wind	*MW*	5,000	500
Solar PV	*MW*	2,500	1,170
Biomass	*MW*	200	0
Fossil gas	*MW*	4,900	1,800
Hydro	*MW*	230	0
Pumped storage	*MW*	290	0
Waste	*MW*	80	30
Interconnector Capacity			
Import from GB	*MW*	1,000	450
Export to GB	*MW*	1,000	500
Import from France	*MW*	700	0
Export to France	*MW*	700	0
Synchronous Condenser Capacity			
Synchronous condenser	*MWs*[16]	14,160	3,440

[16] Megawatt-seconds (MWs) are the units of inertia and are not synonymous with Megawatts (MW). The synchronous condensers in this study have a ratio of inertia produced per electricity used of 400 MWs per MW, i.e., a 4,000 MWs asset would require 10 MW of import capacity from the grid to power it.

2.1.2 Commodity and carbon prices

We have derived our commodity and carbon price assumptions for this study from the *International Energy Agency World Energy Outlook (IEA WEO) 2021* publication. We have aligned our assumptions of the CIF ARA[17] hard coal and Brent Crude[18] oil prices with the Stated Policies scenario; 73 $/tonne and 84 $/bbl respectively in 2030.

We have assumed that the price of NBP[19] fossil gas is set by the cost of HH[20] fossil gas imported as liquified natural gas (LNG) from the United States. The price of delivered fossil gas included the assumed costs of liquefaction, transport, and regasification, in addition to the 3.9 $/MMBtu cost of traded HH fossil gas in the Stated Policies scenario of the *IEA WEO 2021*. The calculated price of NBP fossil gas, 64 p/therm or 25 €/MWh, was overlayed with a monthly seasonality calculated based on historical variation seen in European fossil gas prices.

The cost of fossil gas delivered to each power plant was assumed to include either an annual (per kW) or short-term (per MWh) gas capacity charge, sourced from Gas Networks Ireland (GNI)[21] or Gas Market Operator (GMO) NI[22] for plant in ROI and NI respectively. Fossil gas-fired plant are assumed to switch from annual to short-term tariffs as their load factors decrease from historical outturn.

We have aligned our assumptions for EUA[23] and UKA[24] carbon prices with the 'European' carbon price of 93 €/tonne presented in the Sustainable Development scenario of the *IEA WEO 2021*.

2.1.3 Electricity demand

Our demand assumptions consist of two tranches of load on the all-island system:

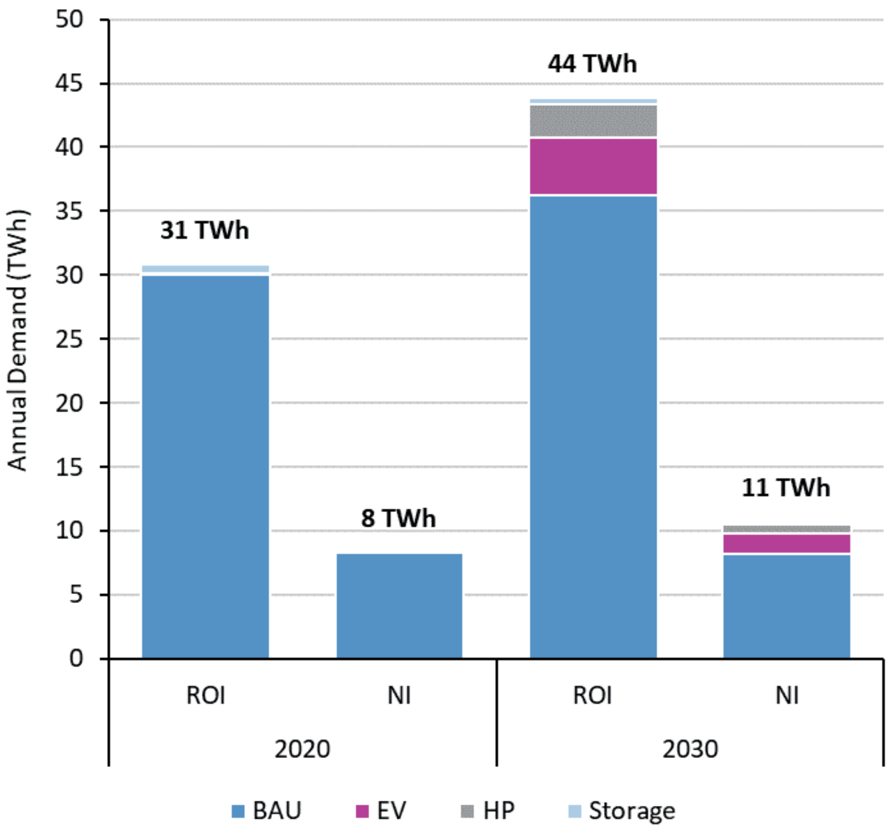
- A relatively inflexible business-as-usual (BAU) component, representative of rigid domestic, commercial, industrial, and data centre demand. We have sourced our figures from the Median scenario of EirGrid and SONI's *Generation Capacity Statement (GCS) 2021*[25], having subtracted the contribution of electric vehicles (EVs) and heat pumps (HPs) from the 2030 total. Data centres contribute around 30% of the 36 TWh BAU demand in ROI, as stated by EirGrid in the *GCS*. BAU demand in NI totals around 8 TWh. Some demand-side flexibility is included within these figures; around 360 and 120 MW[26] of load in ROI and NI respectively is assumed to be able to turn-down during hours of system tightness, with a further 160 and 50 MW being able to shift load profile within each day.

[17] North-West European coal price (Amsterdam-Rotterdam-Antwerp) including cost, insurance, and freight.
[18] North-West European crude oil hub based in the North Sea.
[19] National Balancing Point, a virtual trading hub for fossil gas based in the United Kingdom.
[20] Henry Hub, a physical trading and distribution hub for fossil gas based in Louisiana, United States.
[21] Gas Networks Ireland 2021/22 Tariffs
[22] Gas Market Operator NI 2021/22 Tariffs
[23] European Union Allowances, carbon credits used within the EU Emissions Trading System (EU ETS).
[24] United Kingdom Allowances, carbon credits used within the UK Emissions Trading System (UK ETS).
[25] *Generation Capacity Statement 2021*
[26] European Commission study on demand-side response

- A more flexible contribution from EVs and HPs. We have aligned our deployment figures of both technologies with the *Climate Action Plan 2021* in ROI and the *TESNI 2020* Accelerated Ambition scenario in NI. A total of 1,000,000 EVs (4.4 TWh) and 600,000 HPs (2.7 TWh) are considered in ROI, with 370,000 EVs (1.6 TWh) and 160,000 HPs (0.7 TWh) in NI. Around 25% of the EV demand in each jurisdiction is assumed to be flexible, shifting hours of charge in response to price signals within each day. HPs are assumed to be relatively inflexible.

The total demand modelled in ROI and NI is presented in Figure 5 below. In aggregate, the assumptions above result in an approximately 80:20 split between ROI and NI. This demand-weighted ratio has been used throughout this study to divide deployment of dedicated DS3 service capacity such as synchronous condensers, as well as system-level costs and benefits such as the cost of procurement in the capacity market (as is the case under current policy).

Figure 5: Annual electrical demand projections in ROI and NI



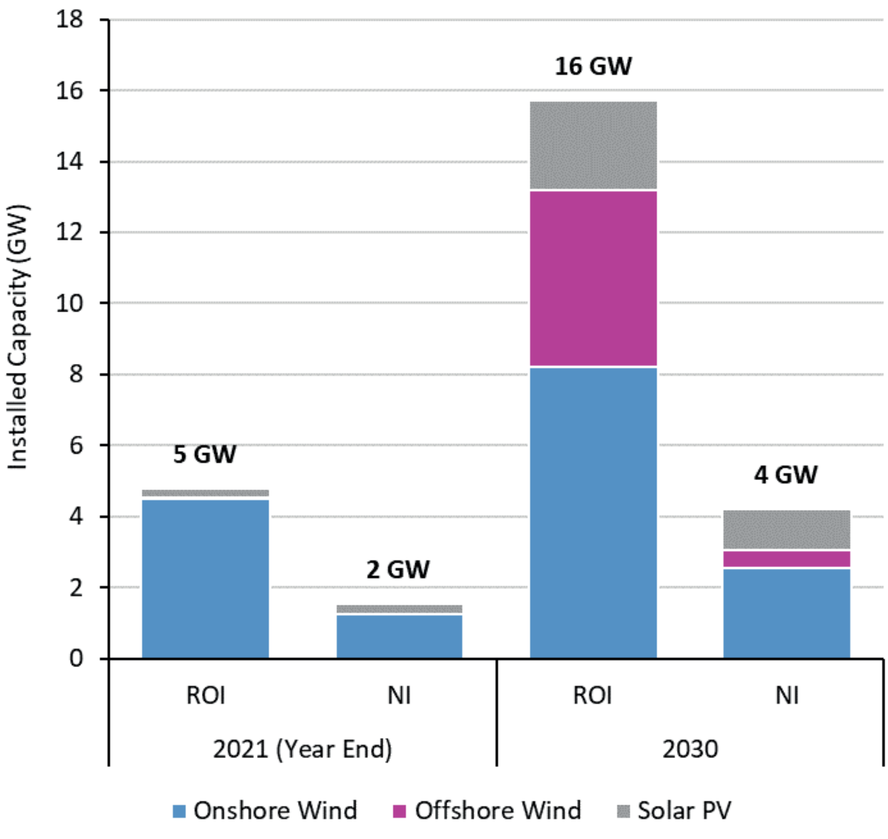
2.1.4 Generation capacity

We have aligned our assumptions of renewable wind and solar generation capacity with the 2030 targets presented in the *Climate Action Plan 2021* in ROI, and the Accelerated Ambition scenario of the *SONI TESNI 2020* in NI:

- 8,200 MW of onshore wind, 5,000 MW of offshore wind, and 2,500 MW of solar PV in ROI; and
- 2,540 MW of onshore wind, 500 MW of offshore wind, and 1,170 MW of solar PV in NI.

Figure 6 below presents the wind and solar capacities assumed in all scenarios, with comparison to those installed at the 'end of 2021' as presented in the *GCS 2021*.

Figure 6: Projected renewable generation capacity in ROI and NI



To enable the integration of these ambitious capacity targets, we have modelled an all-island system with a comprehensive suite of zero-carbon system services provided by technologies including short-duration storage and synchronous condensers. We have assumed that synchronous condensers commissioned throughout the all-island system can provide more than the 17,500 MWs inertia required to maintain the rate-of-change-of-frequency (RoCoF) limit of 1 Hz/s in all hours[27].

[27] Although no absolute inertial floor is considered in this modelling, 17,500 MWs is required to maintain the RoCoF limit during hours in which the largest infeed, the 700 MW Celtic Interconnector, is active.

Despite the benefits conferred by these zero-carbon solutions in addressing the curtailment of renewables, the extent of the capacity assumed in these targets results in significant levels of dispatch-down in the forms of oversupply and constraint. As is presented in Sections 2.3.2 and 3.3.1, the build-out of energy storage represents a potential solution to these challenges.

We have then utilised our in-house capacity market model to simulate the Capacity Remuneration Mechanism (CRM) out to 2030 in ROI and NI, to determine the build-out of fossil gas-fired capacity required to maintain a de-rated capacity margin (DRCM) of around 4% net of the all-island reserve requirement. Although we have assumed that wind and solar capacity does not participate in the CRM directly, we have considered the de-rated capacity contribution provided by these technologies in the calculation of DRCM. The decommissioning schedule of existing fossil gas-fired plant, and the short-term commissioning of new capacity, has been aligned with the *GCS 2021*. In total, around 4.9 GW of fossil gas-fired capacity is assumed in ROI, with 1.8 GW in NI.

The de-rated capacity of energy storage deployed in I-SEM also contributes towards the targeted capacity margin, with assets of longer duration being assigned greater de-rating factors. We have evaluated the benefits conferred by this contribution as detailed in Section 2.2.6.

The remainder of the generation fleet in both jurisdictions is comprised of renewable generation technologies. Around 200 MW of biomass-fired capacity is considered in ROI, along with 230 MW of existing conventional hydro capacity. Around 90 and 30 MW of existing waste-to-energy capacity remains in ROI and NI respectively, and is considered as 50% renewable in line with the *GCS 2021*.

2.1.5 Interconnection

Throughout the scenarios of this study the I-SEM day-ahead market is assumed to be coupled directly to the neighbouring British and French markets via four interconnectors. The Moyle Interconnector, which connects Northern Ireland and Scotland, is assumed to have achieved an export capacity of 500 MW, in-line with EirGrid's stated intent in the *GCS 2021*. Import capacity into NI is assumed to remain at 450 MW. Dispatch of the East-West HVDC Interconnection (EWIC) between Ireland and Wales is also modelled within this study, with a maximum capacity of 500 MW in each direction.

We have also included the Greenlink (500 MW to and from GB) and Celtic (700 MW to and from France) interconnectors in this study, based on evaluations of their feasibility and business cases. The North-South Interconnector between Ireland and Northern Ireland is also assumed to have commissioned prior to the 2030 horizon of this study, as is assumed in the *GCS 2021*.

2.1.6 Energy storage capacity

The Base Case and each of the scenarios explored in this study considers a distinct mix of energy storage capacity installed on the all-island system. In the Base Case, we model 700 MW of 0.5-hour duration storage capacity throughout ROI and NI. These assets cannot participate in the day-ahead market, instead being modelled as providing DS3 services such as fast frequency response (FFR) and operating reserve (POR – TOR2).

The assumptions around the build of this dedicated DS3 service providing capacity are held constant across all scenarios, as is the inclusion of the existing 290 MW Turlough Hill pumped hydro storage plant. However, further storage capacity is modelled in each scenario. The capacity and durations assumed are presented in Table 6 below.

A total of 2 GW of incremental storage capacity above the Base Case is modelled in each scenario, this capacity being modelled as participating in the I-SEM day-ahead market. Storage capacity of all durations has been split between ROI and NI on a demand-weighted basis.

Table 6: Energy storage capacity and duration assumptions in ROI and NI

I-SEM Storage Assumptions	Units	Short	Medium	Long	Extra Long	Varied
ROI Storage						
0.5-hour (DS3-only)	*MW*	560	560	560	560	560
2-hour	*MW*	800	0	0	0	200
3-hour	*MW*	800	0	0	0	200
4-hour	*MW*	0	800	0	0	200
6-hour	*MW*	0	800	0	0	200
8-hour	*MW*	0	0	800	0	200
10-hour	*MW*	0	0	800	0	200
24-hour	*MW*	0	0	0	800	200
100-hour	*MW*	0	0	0	800	200
NI Storage						
0.5-hour (DS3-only)	*MW*	140	140	140	140	140
2-hour	*MW*	200	0	0	0	50
3-hour	*MW*	200	0	0	0	50
4-hour	*MW*	0	200	0	0	50
6-hour	*MW*	0	200	0	0	50
8-hour	*MW*	0	0	200	0	50
10-hour	*MW*	0	0	200	0	50
24-hour	*MW*	0	0	0	200	50
100-hour	*MW*	0	0	0	200	50

We have not made explicit assumptions around the storage technologies that make up these portfolios, instead modelling each tranche of capacity with round-trip efficiencies[28] representative of a broad range of established and emerging technologies; decreasing from 85% for the shortest 0.5-hour duration assets, to 60% for the 100-hour duration capacity[29]. Storage capacity of 6 or more hours duration has yet to be demonstrated in the all-island system, though longer duration technologies have been proven in other markets. Some of these emerging technologies include:

- Pumped hydro energy storage (PHES)[30];
- Compressed air energy storage (CAES)[31];
- Liquid air energy storage (LAES)[32];
- Thermal energy storage, e.g., molten salt, 'hot rocks'[33]; and
- Novel battery compositions, e.g., vanadium redox flow, NaS and $NaNiCl_2$ batteries[34].

2.2 Modelling methodology

2.2.1 Wholesale electricity market modelling

We have developed an in-house pan-European wholesale power market model covering Ireland, Great Britain, and the majority of mainland Europe for the purpose of power market studies. The model sits within PLEXOS, a third-party commercial software that is widely used in the power and utilities industry for market price projections, asset dispatch modelling, network analysis and other purposes. Our 'Pan-EU' model is configured with key inputs and scenario assumptions such as commodity prices, plant build and retirement, and hourly demand, wind, and solar profiles, and has detailed representations of generator technical parameters and interconnection between countries. The model engine carries out a least cost optimisation across over 40 interconnected European markets to project hourly generator dispatch and market prices, taking full consideration of plant operational constraints.

The hourly demand shape and renewable profiles, in both I-SEM and other European markets, are based on outturn from a 'base weather year' of 2017. Wind and solar profiles have been corrected for dispatch-down actions. 2017 represents a broadly 'P50' year, with limited extreme weather or demand events throughout Europe. Wind and solar assets are modelled as aggregated units in PLEXOS, with load factors and output profiles characteristic of averages over multiple site locations in each European market. Where support schemes incentivise variation in bidding behaviour between assets, we model several 'objects' in PLEXOS per market that reflect this behaviour. A second distinction is made between existing and new-build wind generators, with the latter assumed to have a higher load factor. We consider repowering of legacy wind plant towards the tail-end of their economic life.

[28] The round-trip efficiency of an energy storage asset is the proportion of the energy taken in while charging that can be released at a later time, after losses during the charging and discharging cycle.
[29] A comprehensive breakdown of round-trip efficiency assumptions is given in Table 11 on page 58.
[30] Pumped hydro energy storage
[31] Compressed air energy storage
[32] Liquid air energy storage
[33] 'Hot rocks' energy storage
[34] NaS battery composition

In this study we have run the model in 'unconstrained' mode, representative of the I-SEM day-ahead market, and others in Europe. Generators, interconnectors, and storage assets are dispatched based on their short-run marginal costs. We have not explicitly modelled re-dispatch of plant from their ex-ante positions in the day-ahead schedule to account for DS3 limits in I-SEM, having assumed that these limits are maintained by zero-carbon system services as discussed in Section 2.1.4. Re-dispatch of plant to account for transmission constraints is also not considered within the modelling of this phase of study, instead being explored in Section 3.

In all scenarios we have modelled the interconnector flows to and from I-SEM as fixed in their optimised dispatch from the Base Case.

2.2.2 Overview of end consumer cost-benefit analysis

We have calculated the net costs and benefits conferred to end consumers in I-SEM at the system-wide level by the deployment of the storage capacity modelled in each scenario relative to the Base Case. We have analysed both the cost of delivering the storage technologies and the economic impact of the storage asset dispatch in the I-SEM markets and arrangements. The following costs and benefits have been evaluated in this phase of study:

- **Storage technology costs**: The annuitized capital cost of delivering the incremental storage capacity, net of CRM contract value;
- **Wholesale 'cost to load'**: The net change in the total cost paid out to generators to meet demand levels, from movements in the wholesale power price;
- **PSO support costs**: The net change to the Public Service Obligation (PSO) levy cost of supporting renewable capacity, from movements in captured power prices; and
- **CRM procurement costs**: The net reduction in the cost of provision of dispatchable capacity in the CRM from the de-rated capacity contribution of the incremental storage assets.

The costs and benefits calculated in this analysis apply for the year of the modelling horizon only, 2030, and do not include any preceding or subsequent costs or benefits incurred or received in other years. For example, the total cost associated with the build-out of storage infrastructure is assumed to be annuitized across its economic lifetime, according to a weighted average cost of capital (WACC); the cost presented is that incurred by consumers in the year 2030.

2.2.3 Storage technology costs

Given the wide range of established and emerging storage technologies represented within this study, we have used a range of assumptions around capital costs, economic lifetimes, and WACCs to build up blended annuitized cost assumptions for the incremental storage portfolios in each scenario. For all durations of energy storage, the value provided from CRM contracts assumed in Section 2.2.6 below has been netted off the total assumed costs.

The cost of storage assets with durations between 2 and 6 hours has been estimated using lithium-ion BESS as a proxy. We have used internal Baringa assumptions for capital and operating costs, assumed annuitized over 15 years at a WACC of 8%. Due to the relatively nascent nature of these assets in Ireland the resultant annuitized cost values assumed should be considered indicative, having been calculated using a combination of publicly available sources and market intelligence primarily from elsewhere in Europe.

Capital and operating cost assumptions for pumped hydro and compressed air energy storage have been used as proxies for those of technologies with storage durations greater than 6 hours. Given the spread of values available publicly, and the range of efficiencies and durations of existing sites, we have considered multiple sources in our assumptions. These include Mott MacDonald[35], the International Renewable Energy Agency (IRENA)[36], and Energinet[37]. The capital cost 'per MWh' of these technologies has been scaled up to represent the longest durations considered in this study, with a further linear adjustment made to reflect the efficiency of the storage assumed relative to that presented in the sourced data. Economic lifetimes of 50 and 40 years have been assumed for PHES and CAES respectively, each at a WACC of 6%. As with the assumed BESS costs, the results of this calculation should be taken as indicative given the emerging nature of these technologies, particularly at longer durations.

The annuitized capital cost of each storage duration is presented in Table 11 on page 58, net of the assumed CRM contract value.

2.2.4 Wholesale market 'cost to load'

The total cost of electricity purchased in the day-ahead market to meet demand (and paid to generators), or 'cost to load', is ultimately passed on to end consumers in ROI and NI. This cost component has been calculated in each scenario using the hourly I-SEM demand, net of demand from storage assets, and day-ahead price. Dispatch of energy storage capacity within the model influences the cost to load of the I-SEM system by charging during hours of low price, increasing the effective total demand and power price in the day-ahead market. Conversely, by discharging during hours of high price, storage assets can act to moderate extreme price periods and reduce the cost to load. The net effect of these actions will depend on the capacity, duration, and efficiency of the storage asset.

2.2.5 Public Service Obligation (PSO) costs

The Renewable Electricity Support Scheme (RESS) in ROI subsidises renewable generation capacity by providing a two-way contract-for-difference (CfD)[38] at a fixed nominal strike price. We have assumed that all new-build wind and solar capacity in ROI is supported by RESS, or an equivalent scheme, with the cost of support being paid by end consumers via the PSO levy[39]. As all scenarios consider the same installed wind and solar capacity, the strike price received by each technology does not differentiate the cost borne by end consumers between scenarios. Instead, the relative costs of supporting plant under RESS contracts varies depending only on the captured power price of assets under these contracts.

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[35] Storage cost and technical assumptions for BEIS

[36] Renewable Energy Cost Analysis: Hydropower

[37] Technology Data for Energy Storage

[38] Under a two-way CfD, a generator receives a set value per MWh produced, the 'strike price'. When the market price falls below the strike price, the generator receives a top-up payment to supplement their market revenue. When the market price exceeds the strike price, the generator must pay back the difference. Under RESS, the strike price is nominal.

[39] The cost of supporting any new-build renewable capacity under corporate power-purchase agreements (CPPAs) would not be recovered directly using the PSO levy, and so would not contribute to this cost. Given the uncertainties around CPPA policy in Ireland we have not included this route-to-market in the calculation.

The load factors of plant under these contracts, before dispatch-down actions are considered, have been assumed to be:

- 35% for onshore wind;
- 45% for offshore wind; and
- 11% for solar PV.

Movements in the captured prices of wind plant also impact the cost of supporting assets under the legacy Renewable Energy Feed-in Tariff (REFIT) scheme in ROI. We have assumed that the existing onshore wind plant under these one-way CfD[40] contracts have load factors of 30%. As with the RESS scheme, the capacity assumed under REFIT contracts does not vary between scenarios, and so the relative contributions to the PSO levy are independent of the REFIT strike price.

We have assumed that new-build wind and solar capacity in NI is supported by a two-way CfD mechanism, analogous to RESS or the current UK CfD scheme, with the associated PSO costs quantified using the same methodology and assumptions as in the ROI calculation. Existing renewable capacity in NI has been supported by the legacy Northern Ireland Renewables Obligation (NIRO) scheme, under which support is made to generators on a per MWh basis[41]. The nature of this scheme means that the cost incurred by end consumers is independent of the captured prices of renewables.

2.2.6 Capacity market procurement costs

Under the all-island CRM, energy storage assets are assigned de-rating factors based on their capacities and durations. Build-out of storage assets in the scenarios explored in this section therefore contributes to the de-rated capacity margin in I-SEM, reducing the need to procure new-build fossil gas-fired capacity relative to the Base Case. We have sourced our de-rating factor assumptions from the *2024/25 T-3 Initial Auction Information Pack*[42], with the assumption that the average storage asset is around 100 MW in capacity.

We have also assumed that storage assets act as price takers in the CRM, and on average receive the existing capacity price cap of 46.15 €/kW, de-rated. New-build fossil gas-fired capacity is assumed to require a higher price, bidding at 100 €/kW. Bid prices of this order have secured contracts for fossil fuel-fired capacity in recent auctions, including the 2023/24 T-4[43] and the 2024/25 T-3[44]. The total cost of the I-SEM CRM is assumed to be divided into ROI and NI on a demand-weighted basis, in-line with current policy. Different bidding behaviour of storage assets in the CRM would shift the cost of the assets incurred by end consumers between the components considered in Section 2.2.2, i.e., a contract price above 46.15 €/kW, de-rated, would reduce the 'CRM benefit' presented, but also reduce the 'storage technology cost' as considered in Section 2.2.3.

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[40] Under a one-way CfD, a generator receives a set value per MWh produced, the 'strike price'. When the market price falls below the strike price, the generator receives a top-up payment to supplement their market revenue. When the market price exceeds the strike price, the generator does not have to pay back the difference, and secures additional revenue. Under REFIT, the strike price is indexed by CPI.

[41] Under the NIRO subsidy, a generator is provided with a certain number of Renewables Obligation Certificates (ROCs) for each MWh produced, which can be sold to suppliers. This represents a 'top-up payment' per MWh, independent of the day-ahead price captured by the generator.

[42] *IAIP2425T-3*

[43] *FCAR2324T-4*

[44] *FCAR2425T-3*

2.3 Results and discussion

2.3.1 Power sector CO_2 emissions

In 2020 a total of 8.4 million tonnes of CO_2 were emitted as a result of electricity generation in the Irish power sector, at an average emission intensity of 296 grams of CO_2 per kWh of generation (gCO_2/kWh)[45]. Between 2020 and the year 2030 modelled in the Base Case, a series of developments in Ireland have been assumed to decarbonise the sector:

- The retirement of emission intensive peat, coal, and oil-fired plant, in-line with Irish and wider European regulation and ambition;
- The extensive deployment of renewable wind and solar capacity as targeted in the *Climate Action Plan 2021*; and
- The provision of DS3 services by enabling technologies such as batteries and synchronous condensers, removing the need for re-dispatch of fossil fuel-fired plant to maintain DS3 limits.

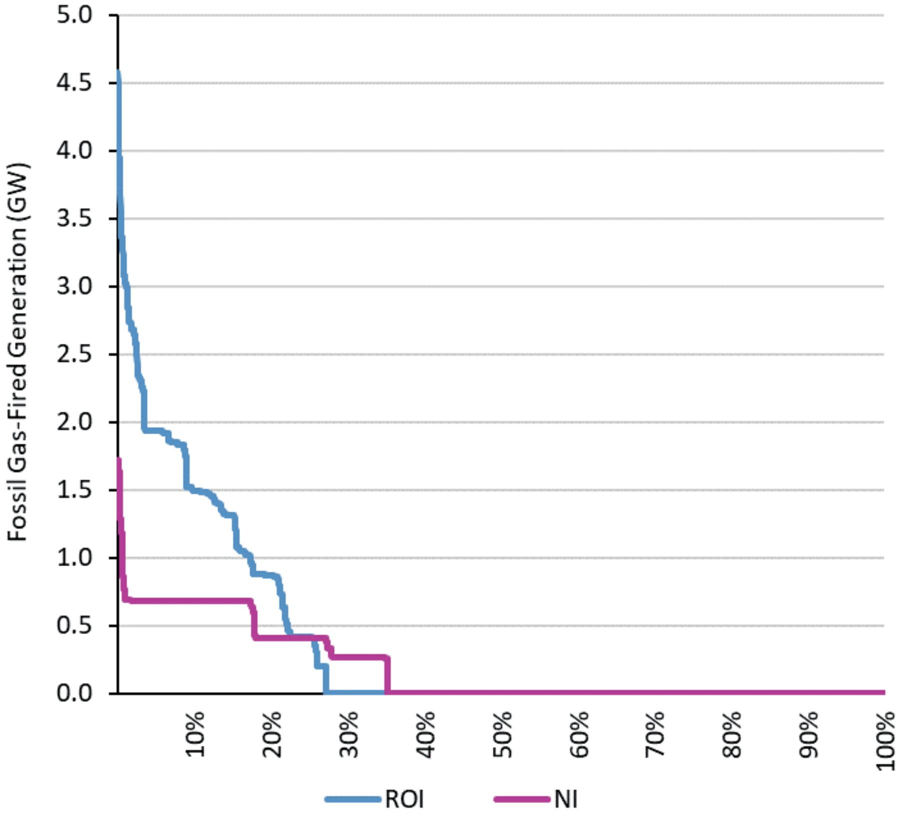
The combined impact of these factors results in a 2030 Irish power sector with a significantly reduced emission intensity of around 25 gCO_2/kWh in the Base Case. The Northern Irish power sector has a higher intensity of around 50 gCO_2/kWh as a result of the lower relative renewable capacity assumed in the *TESNI 2020*. It is important to note that these values do not consider the incremental emissions that would result from re-dispatch of plant to maintain transmission limits (explored in Section 3), instead being reflective of the emission intensity that would result from the ex-ante positions of plant in the 2030 day-ahead schedule. As discussed in Section 2.2.1, we have also not considered re-dispatch of plant to account for DS3 limits, this requirement being assumed mitigated by the comprehensive provision of zero-carbon system services.

In total, **excluding re-dispatch of plant to maintain transmission limits**, just over 1.2 $MtCO_2$ is emitted from the day-ahead schedule in ROI in the Base Case, below the 2030 target of 2-4 $MtCO_2$ presented in the *Climate Action Plan 2021*. These residual emissions result from a minority of hours of high demand and low renewable output, in which dispatchable generation is required to meet demand. Irish fossil gas-fired capacity is dispatched in around 2,400 of these hours, as presented in the duration curves[46] of Figure 7 below. The residual fossil gas-fired fleet acts in a 'peaking' manner, with limited overall volume of generation (around 4 TWh) but a high capacity required in a handful of hours (up to 4.6 GW).

[45] Energy in Ireland 2021

[46] Duration curves present hourly data ordered from highest to lowest. Each duration curve presented in Figure 7 is ordered independently, i.e., the highest value in ROI may not occur in the same hour as the highest value in NI, and so on.

Figure 7: Duration curves of fossil gas-fired generation in ROI and NI in the Base Case

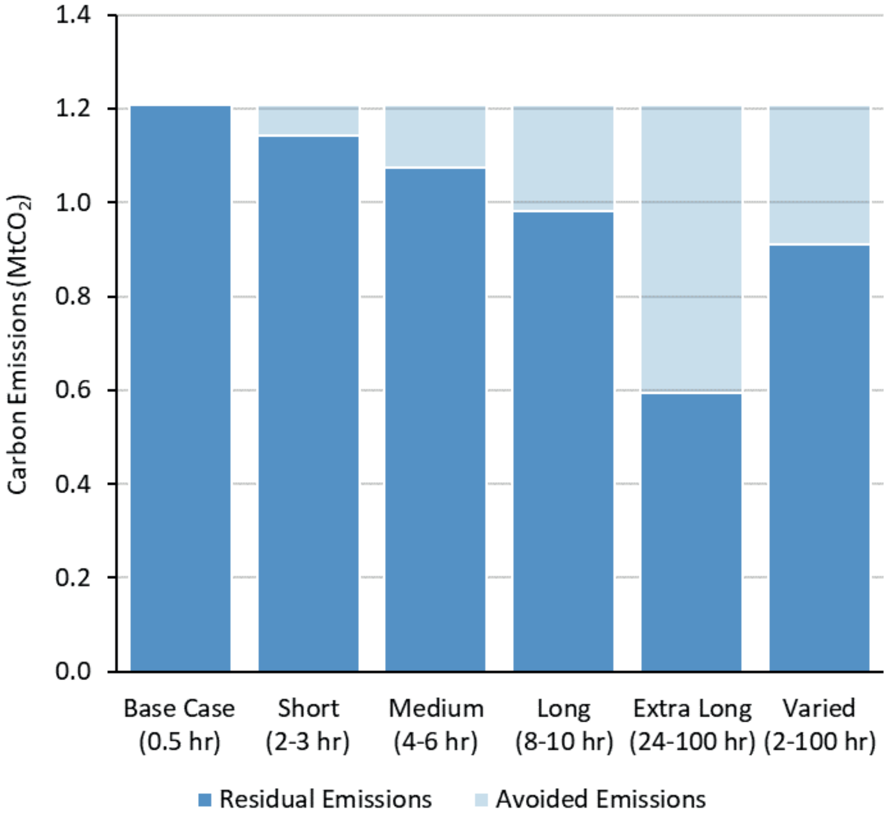


Fossil gas-fired generation of this type is more difficult to displace with zero-carbon generation than 'baseload' operation. Deploying additional renewable capacity offers limited value against fossil gas-fired generation in these hours given that they are typically characterised by low wind and solar output.

Despite the need for fossil gas-fired generation in a quarter of hours, around 10% of potential wind and solar generation is turned down as oversupply during hours in which the available generation exceeds the total that can be accommodated on the system given domestic demand and available export capacity. This wasted zero-carbon electricity provides an opportunity for storage assets to decarbonise the difficult final hours of fossil gas-fired generation in the Base Case.

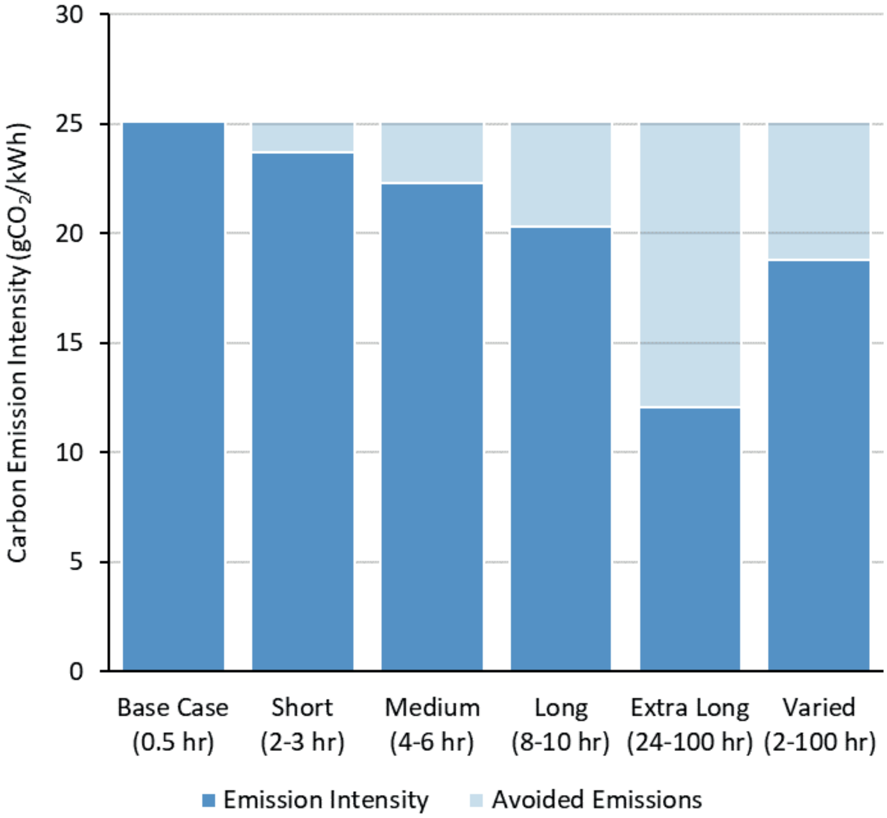
Figure 8 below presents the ROI power sector emissions from our modelled scenarios, each with different distributions of storage duration. The displacement of emissions increases in-line with the duration of the installed storage capacity. At longer durations, the storage assets can take in more renewable generation during hours of excess output and release it over longer periods of low wind and solar output. The 24- and 100-hour duration storage assets in the Extra Long-Duration scenario can displace 1.5 TWh of fossil gas-fired generation in ROI, reducing power sector emissions by over 50%. A total of 0.35 billion cubic meters (bcm) of fossil gas in Ireland is displaced by energy storage in this scenario, over 50% of the total used for electricity generation, reducing Ireland's reliance on imports of the fossil fuel.

Figure 8: ROI power sector CO_2 emissions from day-ahead plant positions



The modelled emission intensity of generation in the ROI power sector is presented in Figure 9 below. An intensity of around 12 gCO_2/kWh is achieved in the Extra Long-Duration scenario, around 50% lower than in the Base Case and 96% lower than the outturn in 2020. Dispatch of energy storage also acts to displace fossil fuel-fired generation and resulting emissions in Northern Ireland, with the greatest benefit also seen in the Extra Long-Duration scenario.

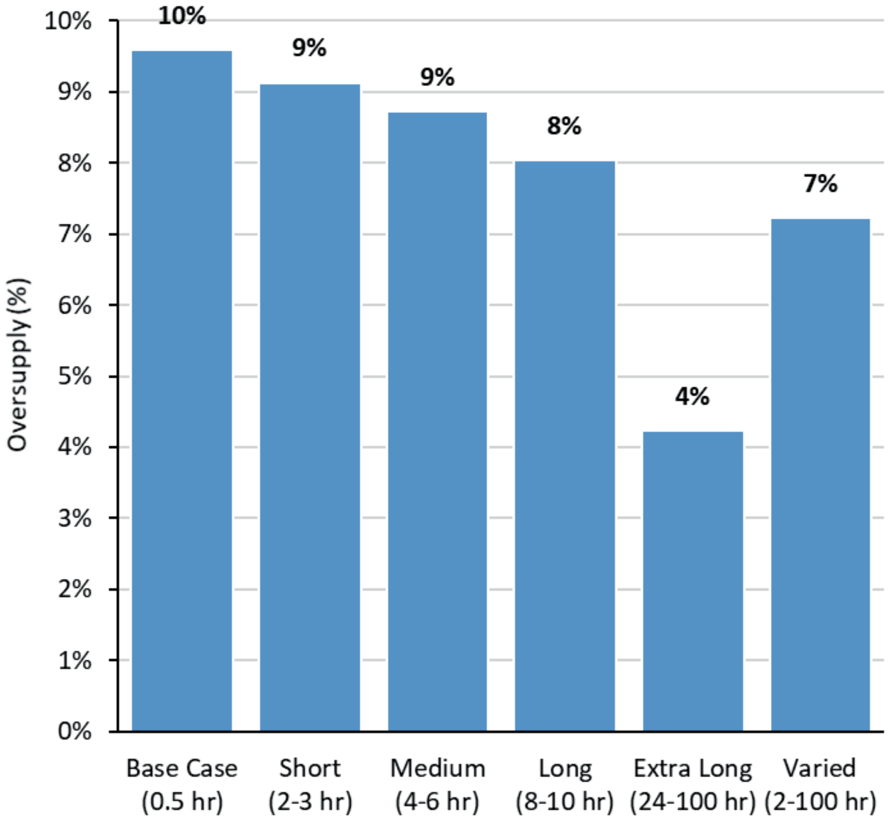
Figure 9: ROI power sector CO_2 emission intensity of day-ahead plant positions



2.3.2 Renewable oversupply

As discussed in Section 2.3.2, the storage assets in each scenario can make use of renewable generation that would otherwise be turned down as oversupply in the day-ahead market. In addition to decarbonising the power sector, the storage assets act to reduce renewable oversupply in ROI, as presented in Figure 10 below. In this way storage assets support the integration of wind and solar capacity on the system in each scenario, with a reduction in oversupply of around 55% projected in the Extra Long-Duration scenario. A similar result is achieved in NI, with oversupply of around 9% in the Base Case being reduced to around 4% in the Extra Long-Duration Storage scenario. The zero-carbon solutions to DS3 limits, including those offered by storage assets, allow zero curtailment of renewables in the Base Case and all scenarios.

Figure 10: ROI total wind and solar oversupply

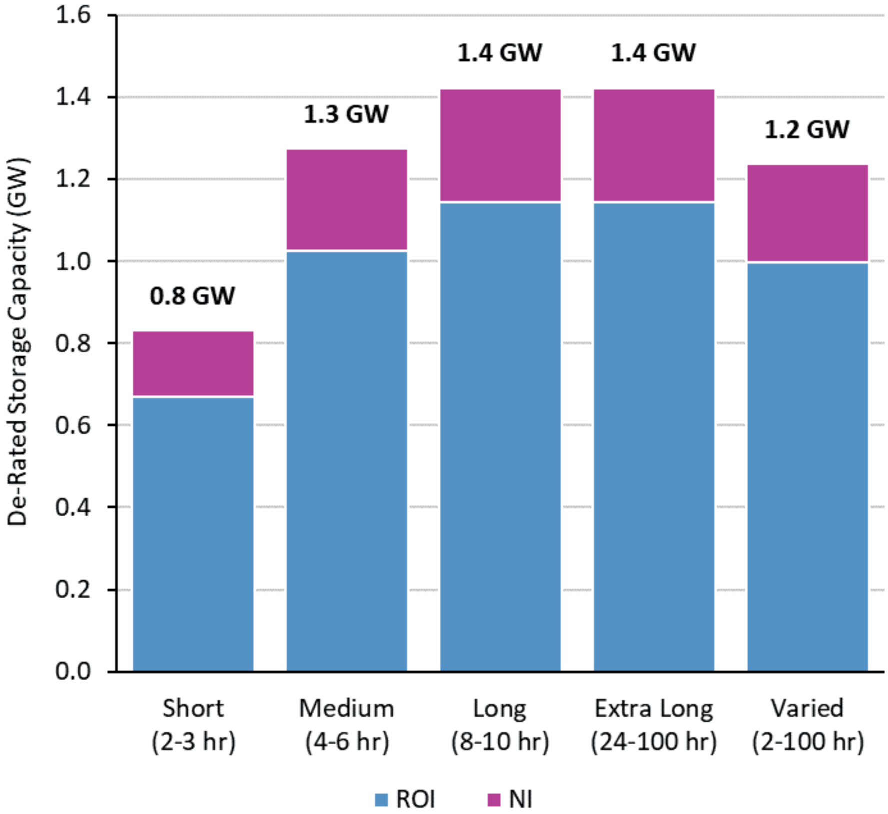


Oversupply of renewable output occurs when the available generation exceeds demand levels, and therefore coincides with hours in which wind or solar generators are at the margin, and the day-ahead price is at, near, or below 0 €/MWh. The reduction of oversupply provided by storage assets therefore acts to support the captured price of renewables, by increasing the day-ahead price in some of these hours. This effect reduces the cost of renewable support payments required under the PSO levy, and the associated cost incurred by the consumer. In addition, by releasing this inexpensive renewable electricity during hours of high price, the storage assets act to displace expensive fossil gas-fired peaking assets during hours in which renewables are not generating, moderating high prices and providing additional savings to end consumers. The value of these benefits is explored in Section 2.3.4.

2.3.3 Security of supply

As a dispatchable technology, energy storage can contribute towards security of supply during hours of peak demand or limited renewable output. High prices in the day-ahead market induced by system tightness in these hours incentivise the dispatch of storage assets. Figure 11 below presents the de-rated capacity of the incremental storage assets modelled in each scenario. Under the current capacity market arrangements, storage assets with durations of 6 hours or more receive de-rating factors of around 70%, a proxy for their average contribution during hours of peak demand. The 2 GW of incremental storage assets modelled relative to the Base Case contributes over 1.4 GW of de-rated capacity across I-SEM in the Long-Duration and Extra Long-Duration scenarios.

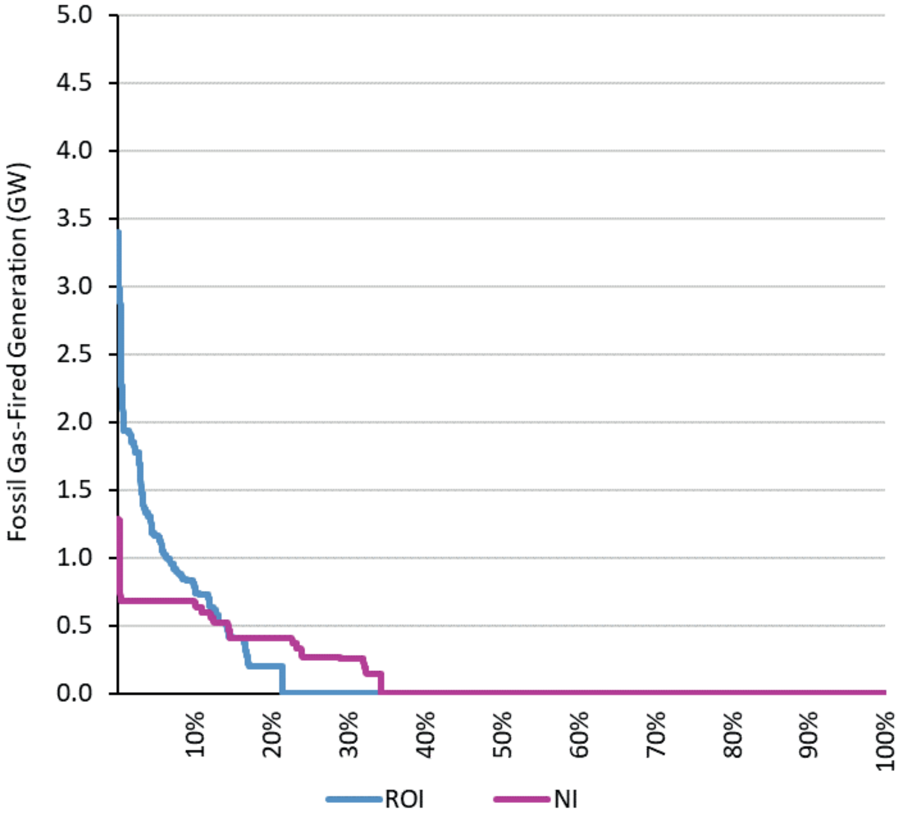
Figure 11: De-rated capacity of incremental energy storage in ROI and NI



The contribution made by energy storage during periods of system tightness within the modelled scenarios can be appreciated in the peak hourly dispatch of fossil gas-fired capacity. As is presented in Figure 12 below, a maximum of around 3.4 GW of fossil gas-fired capacity is dispatched simultaneously in ROI in the Extra Long-Duration scenario, compared to 4.6 GW in the Base Case. Similarly, no more than 1.3 GW of fossil gas-fired capacity is dispatched simultaneously in NI, compared to more than 1.7 GW in the Base Case.

If these storage assets require CRM contracts at lower values than the new-build fossil gas-fired assets that they replace during hours of tight capacity margin, as detailed in Section 2.2.6, then they offer an opportunity to reduce the cost of capacity procurement incurred by end consumers.

Figure 12: Duration curves of fossil gas-fired generation in the Extra Long-Duration scenario



2.3.4 End consumer cost-benefit analysis

The results of the system-level cost-benefit analysis are presented in Figure 13 below. The net costs and benefits to consumers in ROI for each scenario are presented relative to the Base Case, and represent those in the modelled 2030 year alone.

Figure 13: ROI end consumer system-level cost-benefit analysis for 2030

The deployment of energy storage technologies results in a net cost to end consumers in ROI in all scenarios, with the greatest net cost of around €55m in the Extra Long-Duration scenario. This result has been found before considering any local constraint benefits, which are explored in Section 3. The net costs at the system-level are comprised of the following costs and benefits:

- The annuitized capital cost of the storage technologies modelled increases in line with the average duration of the installed storage capacity, being greatest in the Extra Long-Duration scenario. Around €180m and €45m is incurred by end consumers in 2030 in ROI and NI respectively in this scenario. This cost, and those in other scenarios, is partially offset by a series of economic benefits.
- The dispatch of the installed storage capacity in the day-ahead market acts to both support low prices and moderate high prices, by charging and discharging respectively. In the Short, Medium, Long, and Varied Duration scenarios, the latter effect dominates relative to the Base Case and the wholesale price is decreased on a demand-weighted average basis. This effect is greatest in the Medium-Duration scenario, in which moderated peak day-ahead prices reduce the cost to load of the system by around €45m in ROI in 2030. In the Extra Long-Duration scenario, the impact of storage dispatch on low power price hours dominates, and the cost to load increases. Cost savings in NI are achieved in proportion; a benefit of around €10m is achieved in the Medium-Duration scenario.

- By charging during hours of renewable generation, the modelled storage assets support the captured prices of wind and solar generators in the day-ahead market, reducing the top-up support payments required under the PSO levy relative to the Base Case. This saving to the end consumer increases in-line with the average duration of the installed storage capacity. In the Extra Long-Duration scenario, around €100m is saved in ROI in 2030, with around €20m saved in NI.
- By contributing to the de-rated capacity margin in I-SEM, while requiring a lower capacity market contract price than new-build fossil fuel-fired assets, the storage assets modelled in each scenario reduce the cost of capacity provision in the all-island system relative to the Base Case. In the Long-Duration and Extra Long-Duration scenarios, the incremental storage capacity reduces these costs by around €60m in ROI and €15m in NI.

A total net cost of around €20m is modelled in NI in the Extra Long-Duration scenario. All benefits presented in Figure 13 are in addition to those unlocked by provision of zero-carbon system services by the dedicated DS3 capacity modelled in the Base Case and all scenarios.

3 Local constraint benefits

3.1 Scenario assumptions

3.1.1 Overview of assumptions

The key assumptions of the Base Case and each scenario explored in this phase of analysis are presented in Table 7 below. Each is sourced from, or built upon, publicly available data where available. Each assumption is consistent in the Base Case and all scenarios of this phase, with the only differentiation being the duration of installed storage capacity, as is explored in Section 3.1.5.

Table 7: Key County Donegal scenario assumptions in this phase of study

County Donegal Scenario Assumptions	Units	Donegal
Demand		
Annual demand excluding storage	*GWh*	1,100
Peak demand	*MW*	190
EV number	*#*	33,400
HP number	*#*	20,100
Installed Generation Capacity		
Onshore wind	*MW*	930
Offshore wind	*MW*	0
Solar PV	*MW*	0
Biomass	*MW*	0
Fossil gas	*MW*	0
Hydro	*MW*	70
Pumped storage	*MW*	0
Waste	*MW*	0
N-1 Transmission Capacity		
Summer rating	*MVA*	360
Autumn rating	*MVA*	380
Winter rating	*MVA*	400

3.1.2 Electricity demand

We have derived our demand assumptions for County Donegal from available nodal demand projections published by EirGrid, as well as population data. We have sourced our peak demand figure of 190 MW from the sum of the nodal demand projections for the county as stated in the *All-Island Ten-Year Transmission Forecast Statement 2019*[47], having extrapolated out to 2030. The ratio of this figure to the peak demand of the total I-SEM system in our modelling corresponds to around 2.1%. We have made the simplified assumption that this proportion of the I-SEM total also applies to the total annual demand in the county; around 1.1 TWh.

Using county-level population data from the 2016 Irish census[48] as a ratio of the total population figure, we have apportioned around 3.3% of the 1,000,000 projected EVs in ROI to County Donegal. Using this methodology, we have assumed that around 33,400 EVs are registered in the county. An equivalent methodology has been employed for HPs, with around 20,100 assumed in County Donegal.

3.1.3 Generation capacity

In this study we have assumed that, apart from onshore wind, no additional generation capacity is built in County Donegal beyond that active today. The only non-wind capacity assumed corresponds to around 70 MW of hydro capacity: the four Erne units, and around 9 MW of small-scale capacity. No fossil fuel-fired capacity is modelled in the county.

In addition to the approximately 440 MW of existing onshore wind capacity in the county, we have assumed that the complete pipeline of wind capacity as of this study, an additional 490 MW, commissions before 2030. No offshore wind or solar PV capacity has been assumed to commission in the county.

3.1.4 Transmission capacity

We have derived our assumptions around the transmission capacity that connects the network in County Donegal to the rest of the system from the seasonal ratings of each existing line as presented in the *All-Island Ten-Year Transmission Forecast Statement 2019*. In-line with this publication, we have not considered the commission of any additional lines or reinforcement of existing infrastructure.

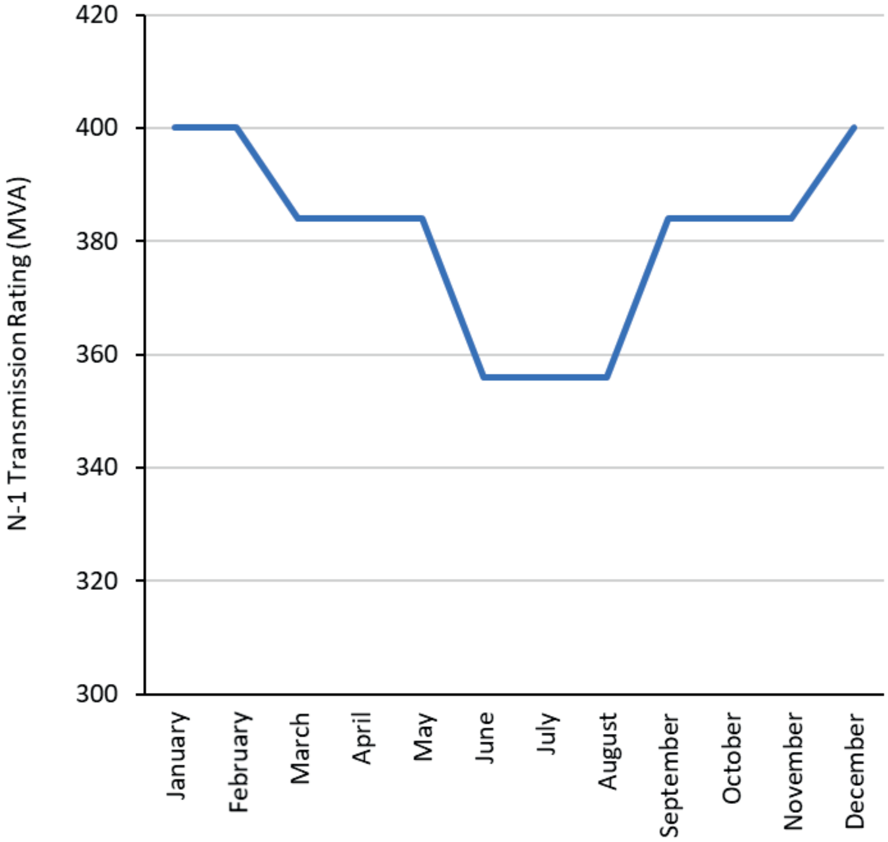
In calculating the total rating from the three lines[49], we have taken a 'N-1' methodology, in which the line with the highest rating is assumed to be unavailable, on a seasonal basis. The total seasonal rating assumed is presented in Figure 14 below.

[47] *All-Island Ten-Year Transmission Forecast Statement 2019*

[48] 2016 Irish Census Data: County Donegal

[49] Cathaleens Falls (CF) – Corraclassy (COR); Cathaleens Falls (CF) – Srananagh (SRA) 1; Cathaleens Falls (CF) – Srananagh (SRA) 2.

Figure 14: N-1 transmission rating in and out of County Donegal



3.1.5 Energy storage capacity

In this phase of study, we have considered the same broad range of storage durations as in Section 2. We have assumed that 400 MW of the energy market storage capacity considered in each scenario is commissioned in County Donegal, and that the dedicated DS3-providing 0.5-hour duration capacity is deployed elsewhere on the network. A summary of these assumptions is presented below in Table 8.

Table 8: Energy storage capacity assumptions in County Donegal

Donegal Storage Assumptions	Units	Short	Medium	Long	Extra Long	Varied
County Donegal Storage						
0.5-hour (DS3-only)	*MW*	0	0	0	0	0
2-hour	*MW*	200	0	0	0	50
3-hour	*MW*	200	0	0	0	50
4-hour	*MW*	0	200	0	0	50
6-hour	*MW*	0	200	0	0	50
8-hour	*MW*	0	0	200	0	50
10-hour	*MW*	0	0	200	0	50
24-hour	*MW*	0	0	0	200	50
100-hour	*MW*	0	0	0	200	50

3.2 Modelling methodology

We have again leveraged our all-island power market model for this phase of the study. Starting with the day-ahead market representation of the I-SEM, i.e., dispatch based wholly on the relative marginal costs of each generator on the system, we have carved out the network of County Donegal from the rest of the system, including the demand and generation capacity in the region.

The two resulting 'regions' within the model are connected via a representation of the transmission capacity in and out of the county, with the limits presented in Section 3.1.4. We have not modelled further transmission limits, either within County Donegal or elsewhere on the network, instead modelling the two regions as 'copper-plate' systems with no limits to transmission. Therefore, the effect of transmission congestion deeper into the network is not considered.

Both regions are modelled as distinct markets with prices set by the marginal bid in that region; the relative difference in plant dispatch in County Donegal representing a proxy for the re-dispatch of plant required to maintain the transmission limits between it and the rest of the network. The discrete marginal market pricing in County Donegal reacts to excess renewable generation in the county; hours in which wind generation is turned down as constraint result in prices of 0 €/MWh.

The storage assets modelled in the county have been configured to capture these hours of low or zero price, incentivised by the opportunity to arbitrage against hours of higher price in the county, in which wind generation cannot meet the total demand in the county. The storage units have not been configured with a targeted spread[50] of regional price, instead the model determines the optimal balance of cycles and export price dynamically.

[50] The 'spread' of a storage asset is the difference between the price paid per MWh to charge the asset, and the price received for the energy on release.

3.3 Results and discussion

3.3.1 Renewable constraint

As a result of its relative isolation from the rest of the all-island network, County Donegal has seen some of the highest levels of renewable constraint in Ireland historically; totalling 5.5% of controllable wind output in the county in 2021, and 8.9% in 2020. May 2021 saw renewable constraint at 19% of controllable site output[51].

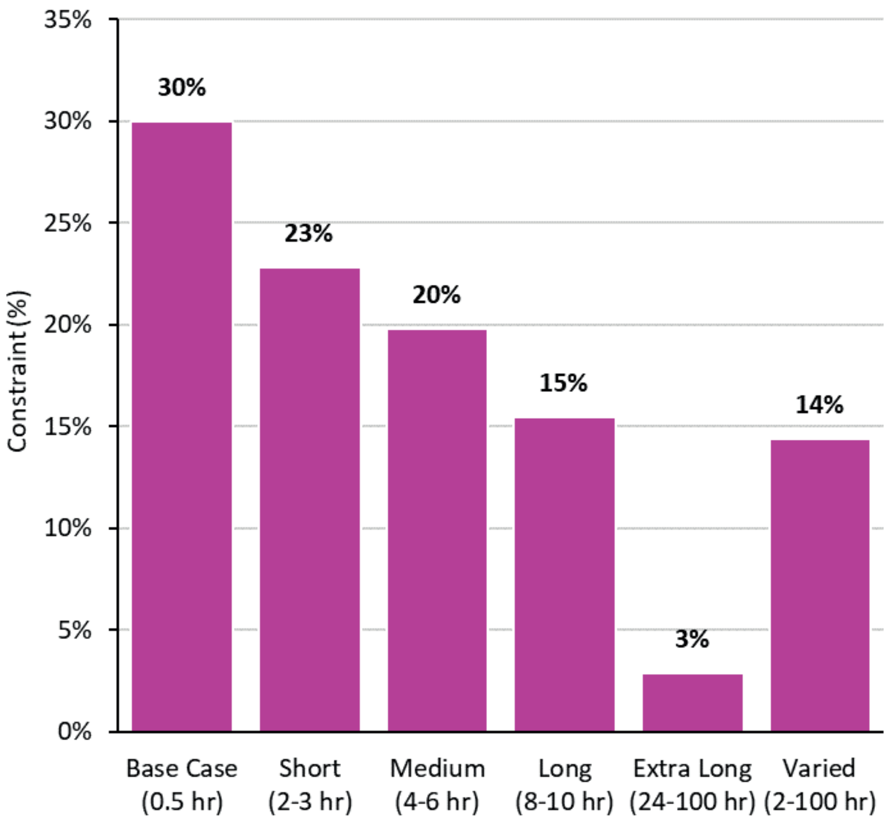
Without reinforcement of the network between County Donegal and the rest of the system, the deployment of the additional wind capacity assumed in the Base Case results in renewable constraint of 30% in the county, including both controllable and non-controllable onshore wind sites. This turn-down of renewable generation is incremental to the oversupply of around 10% in the day-ahead market as was presented in Section 2.3.2.

Constraint actions occur when the hourly renewable generation in a region (net of the local demand) exceeds the available transmission capacity out of the region. Energy storage assets can take in this excess zero-carbon electricity in hours of constraint and release it in hours in which the transmission grid can accommodate it. In this way, storage can enable the delivery of renewable electricity from areas of plentiful wind resource to demand centres on the system, reducing the need for reinforcement of the transmission network. Unlike for oversupply and curtailment, for which they can be located anywhere on the system, storage assets must be strategically located behind the associated transmission congestion to reduce renewable constraint.

Figure 15 below presents the modelled constraint of onshore wind generators in County Donegal in the Base Case and each scenario. Storage assets of all modelled durations act to reduce the level of constraint in the county. This effect increases at longer durations, with a reduction of around 90% achieved in the Extra-Long Duration scenario.

[51] EirGrid Monthly & Quarterly DD Summary Report Spreadsheet

Figure 15: Renewable constraint in County Donegal



3.3.2 Emissions and balancing cost savings

A total of 800 GWh of zero-carbon renewable electricity is turned down as constraint in County Donegal in the Base Case. Under the I-SEM market arrangements, this unused potential generation would need to be replaced with dispatchable generation in the balancing market.

This capacity typically consists of fossil fuel-fired plant, therefore increasing the total power sector emissions of the system. This replacement of turned-down zero-cost generation would also require additional costs in the form of fuel and carbon. Under the I-SEM balancing market rules, plant that are turned-up to replace constrained renewable generation are paid the greater of the imbalance price and their SRMC. Therefore, this incremental operating cost ultimately lands with end consumers, at a minimum.

As discussed in Section 3.3.1, energy storage technologies can make use of renewable generation that would otherwise by turned down as constraint. In the Extra Long-Duration scenario, the 65% efficient storage fleet can reduce renewable constraint in County Donegal by around 700 GWh, and release around 470 GWh of this zero-carbon electricity back onto the grid.

If we make the indicative assumption that CCGTs with average efficiencies of 56% were to be constrained on to replace the turned-down generation in the absence of storage, a total of 150 thousand tonnes of CO_2 ($ktCO_2$) can be saved by the storage capacity in County Donegal alone in the Extra Long-Duration scenario. This saving amounts to around 13% of the total ROI emissions in the day-ahead schedule of the Base Case, or 25% of those in the Extra Long-Duration scenario.

These emissions can be displaced by deploying 400 MW of the 24- and 100-hour duration storage capacity behind the County Donegal transmission constraint, without reinforcement of the network itself. Similarly, locating this capacity in County Donegal can save around €20m of fossil gas costs and €15m of carbon costs that would otherwise be incurred to re-dispatch fossil fuel-fired plant to replace the constrained generation. The savings conferred to end consumers in Ireland by storage assets presented in Section 2.3.4 can be increased significantly by strategic deployment of this capacity in constrained regions of the network, as discussed in Section 4 below.

Although this calculation is indicative and does not consider the effect of transmission constraints deeper into the grid, it demonstrates the value offered by strategic location of energy storage in constrained regions of the network, in the form of both CO_2 emissions and end consumer costs. These benefits have been evaluated based on deployment of 400 MW of the modelled 2,000 MW of energy storage behind a single transmission constraint in the all-island network.

3.3.3 Value of constrained renewable energy

In addition to the cost savings detailed in Section 3.3.2, conferred to end consumers via reduced cost of plant re-dispatch in the BM, the reduction in renewable constraint offers further value, though it is uncertain as to whether this value will be recovered by generators or end consumers.

If the deployment of energy storage in County Donegal is not anticipated by renewable developers in the county, then associated bid prices in RESS auctions could be assumed to factor in the 30% constraint seen in the Base Case. The reduction in constraint provided by the unforeseen storage assets would then unlock additional value for the generators. Assuming that the 490 MW of new-build onshore wind capacity modelled in the county is supported by RESS at an indicative 50 €/MWh strike price, a total of €20m would be recovered by generators in the Extra Long-Duration scenario.

Alternatively, anticipation of storage solutions to constraint in the county would allow the generators to participate in RESS auctions at lower bid prices, affording this €20m saving to end consumers. Applying the same indicative 'per MW' extrapolation as used in Section 3.3.2 to the constraint reduction, and an equivalent support scheme in NI, results in total estimated savings of around €75m and €20m in ROI and NI respectively.

Given the uncertainty in the recovery of this value, we have not included this potential benefit in the end consumer cost-benefit analysis presented in Section 4.

3.3.4 Wider constraint in Ireland

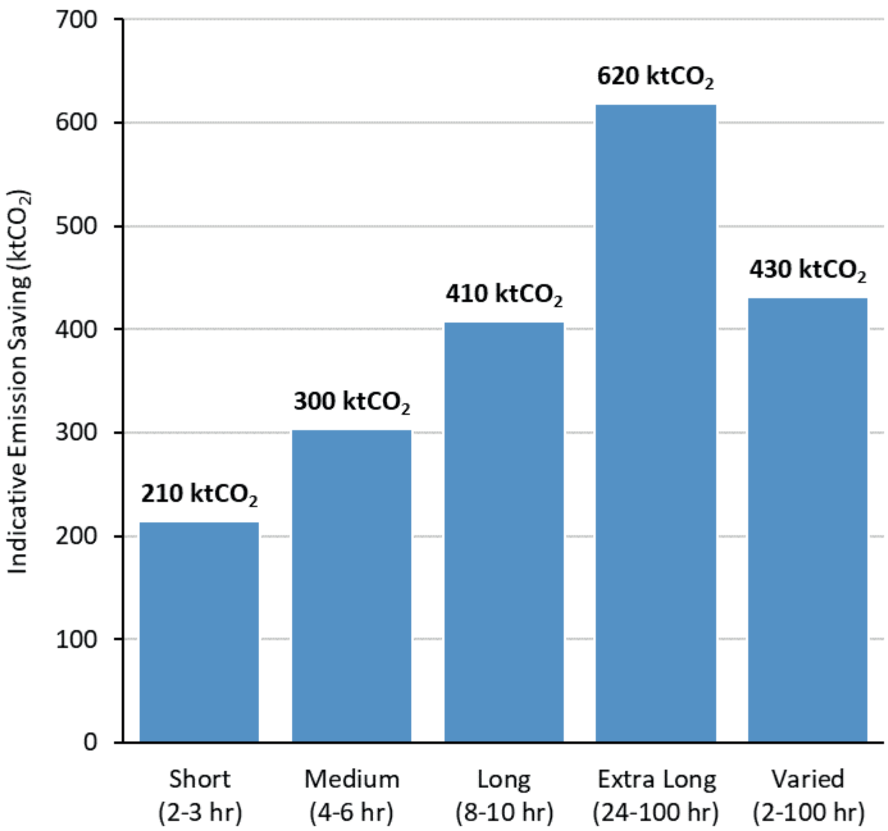
Although County Donegal has seen particularly high levels of renewable constraint in recent years, it is not the only region of the network to see comparable turn-down of renewable output. Almost 2 TWh of renewable output has been turned down as constraint in ROI alone since 2016, with a rapid increase seen in recent years as presented in Figure 16 below. Given the rapid deployment of further renewable capacity throughout the system necessary to achieve the *Climate Action Plan 2021* targets, renewable constraint could be expected to continue to increase if network development does not keep pace.

Figure 16: Historical total constraint of wind output in ROI

Having been calculated using the simplified assumption that the net constraint reduction per MW of installed storage capacity is the same across the 2 GW portfolio of energy market active storage as in the analysis presented in Section 3.3.1, the total emission saving across ROI resulting from reduced renewable constraint is presented in Figure 17 below. This calculation assumes that the storage assets are each placed strategically across constrained regions the network, and behave similarly to those explicitly modelled in County Donegal. If these assets were to be situated in regions of the network with lower levels of renewable constraint, this estimate of the overall benefit would be reduced. This assumption provides the indicative carbon saving that could be unlocked by the modelled storage portfolios by reducing renewable constraint. In reality, other considerations exist under current policy that could incentivise the build-out of storage assets outside of these optimal locations, including some limited locational signals under the CRM, and access to existing grid connections. These policies, and others, are explored further in Section 6.

In the Extra Long-Duration scenario, the overall emission saving in ROI from actions that reduce constraint can displace an indicative 620 ktCO_2 across ROI. A further 150 ktCO_2 can be saved from constraint reductions in NI. Applying the same simplified methodology to the cost-saving calculation estimates total savings in end consumer costs of €140m and €35m in ROI and NI respectively, in 2030 alone.

Figure 17: Total estimated CO_2 emissions saving from reduced constraint in ROI



4 Overall value of energy storage

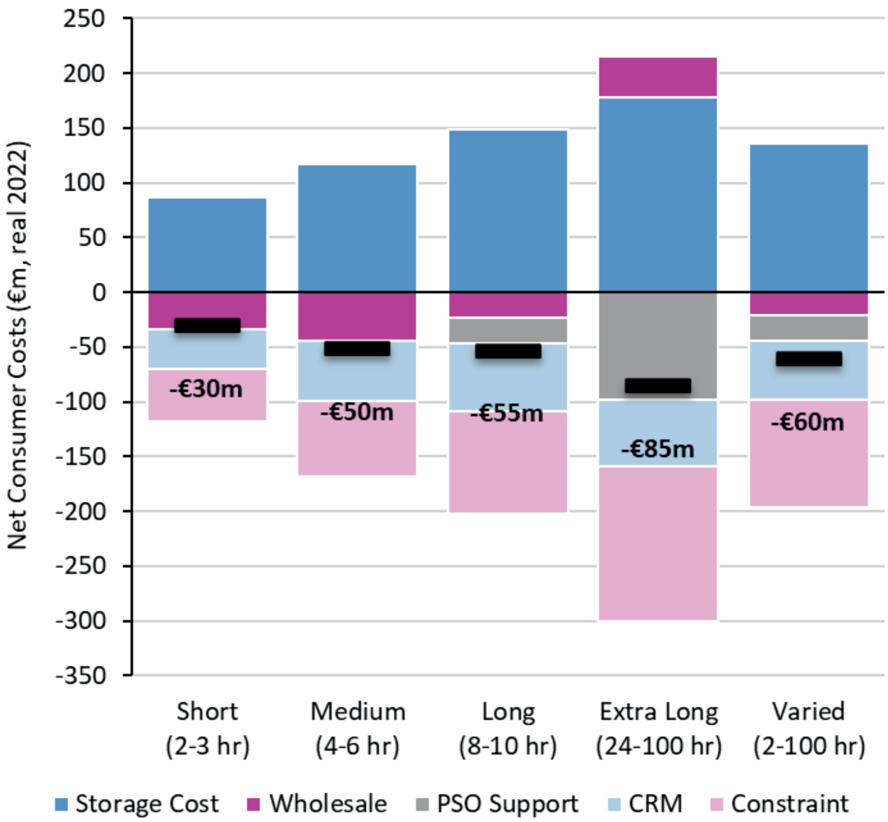
In Section 2, we analysed the costs and benefits conferred to end consumers in Ireland by the participation of 2,000 MW of energy storage of varying durations in the I-SEM day-ahead market. The benefits associated with 1,600 MW of this capacity were attributed to Ireland, with the remaining 400 MW considered under Northern Ireland, an approximate demand-weighted split.

In Section 3 we complemented this analysis with a case study of County Donegal, a constrained region of the all-island network, in which we explored the effect of strategic deployment of 400 MW of storage capacity in the county on renewable constraint, and estimated the further cost savings offered to end consumers by reducing the need to re-dispatch fossil fuel-fired plant.

Figure 18 below presents the total costs and benefits of the incremental storage capacity over the Base Case, including those achieved at both the system and local constraint level in ROI, the latter being indicatively extrapolated from the County Donegal analysis. As detailed in Section 3.3.4 above, this extrapolation assumes that storage assets are situated strategically on the network.

The total saving increases in-line with the average duration of the installed storage portfolio. In the Extra Long-Duration scenario a 1,600 MW mix of 24- and 100-hour duration storage provides the greatest economic benefit to end consumers in ROI, totalling around €85m in the year 2030. In NI, the 400 MW of this storage provides further benefit to end consumers, around €15m in 2030.

Figure 18: ROI end consumer cost-benefit analysis including savings from reduced constraint



5 Key findings of the study

In this study we have set out to determine the benefits of deploying energy storage in Ireland and Northern Ireland, beyond the provision of zero-carbon system services, the benefits of which were evaluated in our *Store, Respond and Save* study of December 2019.

At the system-level, energy storage provides an opportunity to further decarbonise an ambitious Irish power sector, in which the *Climate Action Plan 2021* renewable capacity targets are achieved. Energy storage assets of all durations assist with the deployment of renewables by the reduction of oversupply, making use of the recovered zero-carbon electricity. A portfolio of 24- and 100-hour duration energy storage technologies can remove 50% of the remaining CO_2 emissions in the day-ahead market in Ireland. Provision of zero-carbon system services in all scenarios, by energy storage and other enabling technologies, allows the system to operate without re-dispatch of plant to account for DS3 limits, or renewable curtailment.

Strategic deployment of this energy storage capacity in regions of the network with transmission constraints can address constraint of renewables, and further decarbonise the Irish power sector. The 24- and 100-hour duration portfolio was shown to be able to reduce renewable constraint by 90% in a case study of County Donegal, and ultimately unlock an indicative net saving to end consumers in Ireland of around €85m in 2030.

The results of this study indicate five key findings regarding the benefits of energy storage in Ireland:

- By participating in the Irish **day-ahead energy market**, energy storage can **reduce day-ahead carbon emissions by 50%** by using long-duration storage technologies. This makes a material contribution to meeting ambitious 2030 power sector decarbonisation goals.
- **Strategic deployment** of energy storage in transmission constrained regions of the network **reduces the dispatch-down of renewable generation** from constraints without the need for network reinforcement, unlocking **additional carbon savings**.
- By contributing to **security of supply**, helping to **support renewable capacity**, and **displacing fossil fuels** in the balancing market, energy storage can deliver a **net saving to end consumers in Ireland of up to €85m per year**.
- These benefits are **additional** to the carbon, renewable curtailment, and end consumer savings offered by energy storage through the **provision of zero-carbon system services**.
- Energy storage helps the integration of renewables at all stages by ensuring that generation is not wasted; **reducing oversupply by up to 60%**, **constraint volumes by up to 90%, and curtailment by 100%**.

Given the decarbonisation and end consumer savings unlocked by energy storage technologies throughout this study, particularly those of longer durations, an appropriate policy landscape designed to enable their build-out is vital. In Section 6, Energy Storage Ireland (ESI) highlight the current key barriers to entry for these technologies, and provide a series of recommendations to alleviate them.

6 Policy recommendations from ESI

6.1 Context

In response to the results of our study, Energy Storage Ireland has authored a summary of the key barriers to entry to energy storage technologies in Ireland and Northern Ireland, and recommended a series of actions for stakeholders to address them, and unlock the decarbonisation and end consumer savings demonstrated in this report. This summary is presented in the remainder of this section.

6.2 Energy storage strategy

The flexibility of energy storage means that assets can simultaneously participate in multiple markets and offer diverse services across different sectors as part of the generation, demand, and grid infrastructure. Maximising the inherent benefits that energy storage can provide requires allowing assets to participate in multiple markets and ensuring that the market and policy framework supports investment in a portfolio of energy storage capacities and durations.

Market design and coordination of markets and incentives are crucial policy areas for storage assets and must be approached in a holistic manner to derive maximum benefit from these technologies. It is unlikely that existing market arrangements will deliver the investment signals, particularly for long-duration energy storage, which, as demonstrated throughout this study, offer significant benefits for the decarbonisation of the all-island power system.

Considering the broad range of energy storage technologies, capabilities, and durations available, it is unlikely that any one market arrangement or policy will deliver the required volumes of new energy storage over the next decade. It will likely be the case that different markets and incentives will enable the deployment of different capabilities and durations. Nevertheless, it is essential that the overall policy framework is considered holistically so that market signals do support investment in a broad portfolio of technologies and capabilities.

In the following sections we set out potential options to deliver long-term investment signals and remove barriers for the development of energy storage. This list is non-exhaustive, and other approaches may emerge over the course of the decade. The interactions between different market signals must also be considered, to allow revenue stacking where possible. We recommend that key policy makers in ROI and NI consider these views and engage with industry on a holistic energy storage strategy to determine the most appropriate mechanisms to facilitate the deployment of further energy storage going forward.

The recommendations presented in this section that could be incorporated into such a strategy are summarised in Table 9 below.

Table 9: Summary of energy storage policy recommendations

Policy	Recommendation	Key Stakeholders	Timeline
Energy Storage Strategy	Develop a holistic energy storage strategy in Ireland and Northern Ireland that addresses the key barriers for energy storage and sets out a roadmap of actions, stakeholders, and timelines for the sector.	DECC, DfE	Q1 2023
Capacity Remuneration Mechanism	1. Carry out a review of CRM de-rating factors to ensure appropriate consideration of energy storage. 2. Conduct consultation on policy options to reform the CRM for net zero.	CRU, UR	1. Q3 2022 2. Q1 2023
System Services	Develop an enduring system services framework decision that supports existing and new low carbon service providers.	CRU, UR	Q4 2022
Network Solutions	Publish a consultation on options to enable energy storage as a network solution e.g. cap and floor mechanism, locational capacity contracts, congestion products etc.	CRU, UR, EirGrid, SONI	Q1 2023
Network Charging	Review current import and export network charging arrangements for energy storage to ensure full consideration of the system benefits provided by storage assets and remove unnecessary financial barriers.	CRU, UR	Q1 2023
Connection Policy	Develop a long-term connection policy framework that provides a defined connection route for energy storage, and enables storage projects to connect in a timely manner.	CRU, UR	Q3 2022
Market Integration	Allow full participation of energy storage assets in the energy market: 1. Update TSO systems to allow acceptance and relay of negative physical notifications (instructions for import of energy); and 2. Update TSO systems to allow full integration of energy storage into scheduling and dispatch systems for import and export of energy.	EirGrid, SONI	Q2 2023
Hybrid Projects	Remove barriers to hybrid projects: 1. Allow multiple legal entities behind single connection point; 2. Remove over-install cap on MEC; and 3. Allow sharing of MEC between technologies behind a single connection point.	EirGrid, SONI, NIEN, ESBN	Q4 2022

6.3 Investment signals

In July 2021, the Department for Business, Energy & Industrial Strategy (BEIS) in Great Britain published a Call for Evidence on 'facilitating the deployment of large-scale and long-duration electricity storage'[52]. The paper sought information on the need for long-duration storage in the GB market, and approaches that could be taken to support the deployment of additional storage capacity. The Call for Evidence also identified some of the key challenges associated with deployment of large-scale long-duration storage. We have noted and expanded upon these below, as a policy framework in I-SEM must also seek to address them:

- **High upfront capital costs and long lead times**: energy storage projects often have high upfront capital costs, which can vary per technology, compared to relatively low operating costs. This means that markets based solely on short-term pricing and recovery of marginal operating costs will be unlikely to deliver sufficient revenue or investment certainty for long-duration storage assets. It is also worth noting that some storage technologies require significant construction or engineering work (e.g. pumped hydro), and so can have long lead time to commission.
- **Lack of track record**: while some energy storage technologies such as lithium-ion BESS are proven at scale and can be deployed quickly, other long-duration technologies are emerging and can face additional investment challenges due to their lack of a widespread demonstrated track record. This can limit investor confidence in these technologies, necessitating long-term stable revenue frameworks to overcome these challenges.
- **Revenue certainty**: the flexibility of energy storage assets allows them to stack revenues across multiple value streams; an important facet of the business case for such an asset. However, many of these revenue streams, particularly energy market trading and potentially a future system services arrangement, involve short-term contracting and so provide less visibility on long-term revenues. An exception is the CRM, which in I-SEM can provide fixed contracts of up to 10 years in duration. However, there are associated challenges as addressed in Section 6.3.1 below. It is also important that an individual market does not restrict participation across other revenue streams as this can limit the overall investment potential of projects, e.g., integration issues as outlined in Section 6.4.3.
- **Market signals**: most market revenue streams at present are centred on short-term markets or short-duration products, and so there is little incentive to invest additional capital in long-duration storage capacity. The market has so far delivered significant investment in short-duration, primarily DS3-service providing, BESS. Going forward the market must appropriately capture the full value of energy storage demonstrated in this study. This is important as energy storage assets, particularly those modelled in the Extra Long-Duration scenario portfolio, may be needed to store energy over long periods, rather than repeated cycling; and this value should be adequately remunerated as well. The overall policy design and market signals should not only consider the cost savings, but also the emissions savings that energy storage can provide over competing fossil fuel-fired plant.

[52] *Facilitating the Deployment of Large-Scale and Long-Duration Electricity Storage: Call for Evidence*

In the following sections we have outlined a selection of options across the key pillars of the day-ahead market, the CRM, system services and network solutions that may help facilitate the long-term deployment of energy storage.

6.3.1 Capacity Remuneration Mechanism

The all-island Capacity Remuneration Mechanism (CRM) is designed to ensure that there is sufficient generation capacity in place to meet future electricity demand. The CRM can provide contracts of up to 10 years in duration, and a guaranteed revenue stream for new-build assets. Capacity contracts are awarded via technology-neutral auctions with lead times for new assets to become operational and contribute to capacity requirements. There are several adjustments that could be considered in the CRM to incentivise additional energy storage deployment, including:

- **De-rating factors**: Under the CRM, participants are assigned de-rating factors based on their reliability and contribution to system capacity requirements. Energy storage assets are assigned a de-rating factor based on their capacity and duration. This means that assets that clear in the capacity auctions only receive payments for their de-rated capacity. For instance, the parameters of the recent 2024/25 T-3 Auction applied de-rating factors of around 70% for assets of 6-hour duration or more, down to 10-15% for assets of 0.5-hour duration. Currently, the de-rating thresholds only consider storage durations up to 6 hours, any asset with a longer duration carries the same de-rating. To ensure that signals are sent to procure flexible low-carbon capacity it is necessary to review the current de-rating factors so that they adequately reflect the contribution of energy storage to the system, including assets with durations of more than 6 hours.
- **Price caps**: the current process used to determine the parameters in setting CRM auction price caps is based on the cost of new fossil fuel-fired generation. This approach may not provide sufficient revenue for emerging energy storage technologies, which can require additional financial support at the outset. In July 2021, BEIS published a Call for Evidence on 'Capacity Market options for early action to align with net zero'[53]. The paper highlighted potential options such as segmented auctions with different price caps for low-carbon assets. A similar approach could confer the benefit of allowing new and emerging energy storage technologies to compete to secure long-term capacity contracts.
- **Emissions limits**: the CRM auctions are technology neutral and do not explicitly include CO_2 emissions costs in auction pricing. This can put many energy storage technologies at a disadvantage, particularly when compared to more established fossil fuel-fired plant. The Call for Evidence initiated by BEIS put forward options such as ringfencing capacity for low-carbon generation, or extending long-term capacity contracts only to low-carbon investment. These proposals would help to signal investment towards flexible capacity assets that can contribute to decarbonisation goals in ROI and NI.
- **Delivery periods**: while established technologies such as lithium-ion BESS have relatively fast delivery times compared to fossil fuel-fired generators, other technologies such as pumped hydro, or new emerging storage technologies, may have longer lead times. This should be considered in the development of frameworks for new low-carbon investment in terms of delivery milestones and length of contract support.

[53] *Capacity Market 2021: call for evidence on early action to align with net zero*

6.3.2 System services

The current DS3 system service framework, established in 2017 via the regulated tariff arrangements, has facilitated increasing levels of renewable generation on the all-island power system, as well as investment in new system service provision capability such as the battery storage capacity required to increase the SNSP limit to 75% in 2021. The initiative has been successful in allowing the all-island power system to achieve world leading levels of renewable integration.

The continued growth of renewable generation this decade, combined with a decline in fossil fuel-fired plant as older units are decommissioned, will require further investment in new zero-carbon system service providers to support further relaxation of DS3 limits. Baringa's *Store, Respond and Save* study showed the benefits of moving to a model in which all system service requirements are met by zero-carbon 'non-energy market' providers such as battery storage by 2030.

However, the DS3 service regulated tariff arrangements framework is set to end in April 2024 and clarity has yet to be provided on procurement arrangements after this date. Further arrangements are in development, with a SEM Committee decision on the high-level design for the future system service arrangements having been published in April 2022[54], and further detailed design work expected in 2022. The future arrangements will be a combination of short-term procurement for certain services, or volumes of certain services, supported by longer-term procurement mechanisms. However, uncertainty on the detailed market framework post-2024 means that the current path for new build investment is unclear.

The enduring system service arrangements will need to support existing zero-carbon service providers and provide sufficient investment signals for further new-build providers such as energy storage, particularly where additional service capabilities are required by 2030.

There is also the potential for new service markets to be developed such as congestion products to help alleviate transmission constraints, or longer-term ramping products to manage wind forecast errors, both of which energy storage could participate in. Where new investment in zero-carbon service provision is required, particularly in instances where these technologies may carry a high capital cost, longer-duration procurement mechanisms such as fixed contract auctions, contracts for difference, or bilateral tenders may be appropriate.

6.3.3 Network solutions

Section 3 of this study demonstrated the significant benefits that energy storage can deliver in terms of alleviating transmission constraints for renewable generators, increasing the amount of electricity demand that can be met by renewable energy sources, and contributing substantially to Irish decarbonisation aims. However, there is no locational pricing in the I-SEM or specific investment signal for energy storage that would drive its deployment as a locational solution or an alternative network solution to traditional grid reinforcement. While grid reinforcement lead times can often be lengthy and large-scale infrastructure can be a complex undertaking, energy storage provides a credible alternative in many areas of the grid, as has been demonstrated.

[54] *SEM-22-012*

Potential options to help deliver these locational investment signals include but are not limited to:

- **Congestion products**: as we have detailed in Section 6.3.2 above.
- **Network charging arrangements**: as we evaluate in Section 6.4.1 below.
- **Targeted locational CRM contracts**: more granular locational CRM contracts that incentivise build of storage capacity in specific transmission constrained areas of the grid. The existing CRM does contain a locational element, but this is largely jurisdictional in nature e.g. specific capacity requirements for ROI and NI.
- **Cap and floor mechanism**: an existing regulatory model of this nature operates between GB and ROI to facilitate the development of electricity interconnectors by private developers. A cap and floor mechanism has been stated by BEIS as a potential option to facilitate the build-out of long-duration energy storage. The cap and floor regime provides a minimum revenue allowance, set by the relevant Regulators, to help developers secure financing. When operator revenues fall below this floor, they are topped up by consumers. Conversely, when revenues breach a revenue cap, excess returns are passed on to consumers. The cap and floor levels are calculated based on project costs including financing costs (at the floor) and a return to equity (at the cap). The duration of the current cap and floor regime for interconnectors is 25 years. An alternative to this is a revenue floor with shared upside mechanism, which does not set a fixed cap but sets a proportion of revenues over the floor that would be shared with consumers. The incentive remains for assets to trade optimally and try to maximise revenues from existing and new services, and in doing so maximising consumer savings.
- **Bi-lateral contracts**: this option allows the TSO or DSO to tender for network solutions out to the market, with third-party solutions competing against traditional reinforcement options in terms of deliverability and cost. If an energy storage device from a third party can deliver the required solution in a smaller timeframe and at a lower cost than traditional network reinforcement, then the developer can secure a contract for this service, funded by end consumers.

6.4 Other policy recommendations

6.4.1 Network charging

The Regulatory Authorities in ROI and NI, the Commission for Regulation of Utilities (CRU) and the Utility Regulator (UR) respectively, set charges for network users to recover the costs of operating, maintaining, and developing the distribution and transmission networks. These charges are levied on both the generation and demand side.

Energy storage is in a unique position in that it can be subject to both generation and demand charges for the electricity stored on site (i.e. double charging), and so can face excessive costs for access to and use of the grid. Energy storage is not an end consumer of the electricity stored and cannot be a generator of the electricity released, therefore they should not be treated as either a generation or demand customer under the network charging regime. The CRU decided in September 2020 to cease charging generation use of system charges for commercial storage providers, on an interim basis, pending a wholesale network charging framework review[55].

[55] *Network Charges for Commercial Storage Units Interim Solution*

It is important that these arrangements apply on an ongoing basis to all energy storage technologies. Generation use of system charges are still levied on energy storage in NI, which creates an uneven playing field and imposes higher network costs on local storage assets. As the storage market evolves and longer-duration technologies start to emerge into the market, the requirement for Maximum Import Capacity (MIC) will grow to become at least approximately symmetrical with Maximum Export Capacity (MEC). It is this symmetry in relation to MIC/MEC that is particularly important to unlock the full flexibility of storage assets, allow more effective charging and discharging of assets and broader participation in multiple markets. This is a scenario disincentivised under the current tariff framework due to the application of demand network charges, in particular the MIC-related capacity charge that can impose large costs on projects seeking a higher MIC. A more appropriate methodology may be to adequately reflect energy storage's contribution as a network asset, particularly in terms of alleviation of transmission constraints. This would require a separate charging policy for energy storage that potentially remunerates storage assets behind network constraints, and does not impose excessive costs or double charges for access to and use of the network.

6.4.2 Connection policy

Changes may also be needed to existing connection policy to facilitate the deployment of further energy storage going forward. In ROI the *Enduring Connection Policy Stage 2* (ECP-2)[56] framework published by the CRU in June 2020, sets out an annual batch process whereby generators and energy storage devices looking to connect to the network must apply via annual windows. Eligible projects are then processed in batches and issued connection offers by EirGrid or ESB Networks. Each annual batch is limited to 85 connection offers for large generators/energy storage assets, but there is a cap of 10 on the number of offers that can be processed for standalone energy storage projects per round. Energy storage is processed alongside other generators and applications are prioritised based on earliest date of planning permission grant.

The ECP-2 process has so far seen limited progression of standalone energy storage projects, as projects with earlier planning permissions, mainly solar, have been dominant. The ECP-2 framework set out a roadmap for three annual batches; two batches have been progressed so far, with the final batch under the current framework set to open in September 2022. The connection process beyond this is uncertain (i.e. whether ECP-2 will be extended, or a new policy developed) but it may be necessary to consider a separate route to connection for energy storage assets alongside ECP to facilitate the development of further capacity, particularly in instances in which storage may have locational constraint benefits. This process must be flexible to accommodate existing and emerging energy storage technologies.

The other means of securing a connection offer in I-SEM is through the CRM, with CRU directions mandating that connections be processed for new-build projects successful in recent CRM auctions. However, as noted in Section 6.3.1 above, there are limitations on full and effective participation of energy storage in the CRM.

In NI, there is no batch process, with connections being processed on a case-by-case basis. As per their licences, the SOs, SONI and NIEN, have 90 days to process an application and make a connection offer to the applicant. However, the issue in NI at present is a lack of grid capacity and moratoriums on new connections for projects seeking to connect to the system. This must be addressed to develop a sustainable connection framework for energy storage.

[56] *Enduring Connection Policy Stage 2 (ECP-2)*

6.4.3 Market integration

The current TSO market systems have known limitations that restrict the ability of energy storage to fully participate in the market and utilise their full flexibility. Two of the main limitations are:

- The inability of market interfaces to accept and relay negative Physical Notifications (PNs) as part of scheduling and dispatch to allow charging of energy storage assets. As an interim measure the TSOs have implemented a pre-agreed charging arrangement whereby storage devices can charge up to the lowest of 5 MW, 20% of their MEC, or their MIC in any one period. Any charging required by the storage device outside of this range should only be by explicit MW instruction from the TSO[57]. This limitation impacts the ability of energy storage devices to access their full MEC/MIC capability, and restricts their participation in the energy market. This has been recognised by the TSOs and a work programme is underway to update market systems to allow acceptance and processing of negative PNs[58]. It is important that these changes are brought into place as soon as possible to remove this market integration barrier.
- The inability of energy storage to be fully included in TSO scheduling and dispatch decisions. There are existing limitations with the TSOs' market interface, specifically the ability to allow representation of storage assets in TSO optimisation and scheduling decisions. The impact of these limitations is that the TSOs cannot effectively dispatch storage assets based on their ex-ante positions and these assets cannot effectively carry out energy arbitrage services. Upgrades to the TSOs market interface will be needed to allow full registration of energy storage and a level playing field for storage providers.

6.4.4 Hybrid policy

A hybrid site has multiple generating units, which utilise multiple energy sources, and/or different technology types that are electrically connected behind a single connection point. Hybrid sites enable developers to maximise the use of existing project sites and connections to improve the efficiency and capacity factors of projects while minimising connection costs. For example, an energy storage device co-located with a wind or solar plant can utilise its grid connection and charge using its energy at times of dispatch-down for later release onto the grid.

Hybrid projects are not common in Ireland as there are several barriers to their development. The 'Technology Enablement Workstream', outlined in the *Shaping our Electricity Future Roadmap*, provides a pathway to remove these barriers. A summary of the workstreams is as follows:

- Development of a contractual framework to allow multiple legal entities behind a single connection point by Q1 2022;
- A review of the current 120% MEC over-install policy by Q2 2022; and
- A technical assessment of options for MEC trading behind a single connection by Q4 2022.

It is welcome to see these policy barriers being addressed, and it will be important that these milestones are achieved to start to unlock opportunities for hybrid project development.

[57] *Battery ESPS Grid Code Implementation Note*

[58] *SEM-21-073*

Appendix A Dispatch-down in I-SEM

In the *Shaping our Electricity Future Technical Report*[59], EirGrid and SONI defined three distinct forms of dispatch-down actions in I-SEM that reduce the output of renewable generators below their theoretical maximum. Table 10 below presents a summary of the three types of actions.

To be ‘turned down’ a renewable generator must be ‘controllable’, i.e., it must be possible to remotely disconnect the generator from the network.

Table 10: Dispatch-down actions in I-SEM

Dispatch-Down	Oversupply	Curtailment	Constraint
Definition	Oversupply actions occur for two reasons: 1. Volumes in the day-ahead market at or below the cleared price exceed the total market and/or physical demand; 2. If large volumes of renewable outturn are expected, plant can be incentivised to 'self-curtail' to not be exposed to negative day-ahead prices.	Curtailment actions result from the need for maintain system-wide DS3 limits (operational constraints) including: 1. SNSP limit; 2. RoCoF limit; 3. Minimum inertia; 4. Minimum units for system stability limits.	Constraint actions occur after the day-ahead schedule, to account for local limits in the capacity of the network, often termed 'grid boundaries'. If these limits are due to be exceeded in the day-ahead schedule, plant 'behind' these limits will be turned down.
Which plant?	Any plant on the network.	Any plant on the network.	Plant in the area where the constraint occurs.
When?	In the day-ahead schedule.	In the balancing market.	In the balancing market.
2021 outturn	0.5%	3.0%	4.4%

[59] Shaping our Electricity Future Technical Report

Appendix B Tabulated input assumptions

Table 11: I-SEM scenario assumptions in each phase of study

Scenario Assumptions	Units	I-SEM
Commodity & Carbon Prices		
Coal CIF ARA	*$/tonne*	73
Gas NBP	*€/MWh*	25
Oil Brent	*$/bbl*	84
Carbon EUA	*€/tonne*	93
Carbon UKA	*£/tonne*	82
I-SEM DS3 Limits		
SNSP limit	*%*	100%
RoCoF limit	*Hz/s*	1.0
Minimum inertia limit	*MWs*	0
System stability minimum units - ROI	*#*	0
System stability minimum units - NI	*#*	0
Energy Storage Round-Trip Efficiencies		
0.5-hour (DS3-only)	*%*	85%
2-hour	*%*	85%
3-hour	*%*	85%
4-hour	*%*	85%
6-hour	*%*	85%
8-hour	*%*	80%
10-hour	*%*	80%
24-hour	*%*	70%
100-hour	*%*	60%
Energy Storage Annuitized Costs		
2-hour	*€/kW*	49
3-hour	*€/kW*	59
4-hour	*€/kW*	68
6-hour	*€/kW*	78
8-hour	*€/kW*	88
10-hour	*€/kW*	97
24-hour	*€/kW*	104
100-hour	*€/kW*	117

Table 12: ROI, NI, and County Donegal scenario assumptions in each phase of study

Scenario Assumptions	Units	ROI	NI	Donegal
Total & BAU Demand				
Total demand excluding storage	*GWh*	43,380	10,520	1,100
Total peak demand	*MW*	7,320	1,780	190
BAU annual demand	*GWh*	36,280	8,170	860
BAU peak demand	*MW*	5,990	1,350	140
EV & HP Demand				
EV number	*#*	1,000,000	371,700	33,400
EV total demand	*GWh*	4,430	1,650	150
EV flexible demand	*GWh*	1,110	410	40
HP number	*#*	600,000	158,500	20,100
HP total demand	*GWh*	2,670	700	90
HP flexible demand	*GWh*	0	0	0
Demand-side Response				
Demand-side capacity able to curtail	*MW*	360	120	0
Demand-side capacity able to shift	*MW*	160	50	0
Installed Generation Capacity				
Onshore wind	*MW*	8,200	2,540	930
Offshore wind	*MW*	5,000	500	0
Solar PV	*MW*	2,500	1,170	0
Biomass	*MW*	200	0	0
Fossil gas	*MW*	4,900	1,800	0
Hydro	*MW*	230	0	70
Pumped storage	*MW*	290	0	0
Waste	*MW*	80	30	0
Interconnector Capacity				
Import from GB	*MW*	1,000	450	0
Export to GB	*MW*	1,000	500	0
Import from France	*MW*	700	0	0
Export to France	*MW*	700	0	0
Synchronous Condenser Capacity				
Synchronous condenser	*MWs*	14,160	3,440	0

Appendix C About Baringa

C.1 Our firm and our ways of working

We set out to build the world's most trusted consulting firm – creating lasting impact for clients and pioneering a positive, people-first way of working. We work with everyone from FTSE 100 names to bright new start-ups, in every sector.

You'll find us collaborating shoulder-to-shoulder with our clients, from the big picture right down to the detail: helping them define their strategy, deliver complex change, spot the right commercial opportunities, manage risk, or bring their purpose and sustainability goals to life. Our clients love how we get to know what makes their businesses tick – slotting seamlessly into their teams and being proudly geeky about solving their challenges.

We have hubs in Europe, Asia, and Australia, and we work all around the world - from a wind farm in Wyoming to a boardroom in Berlin. Find us wherever there's a challenge to be tackled and an impact to be made.

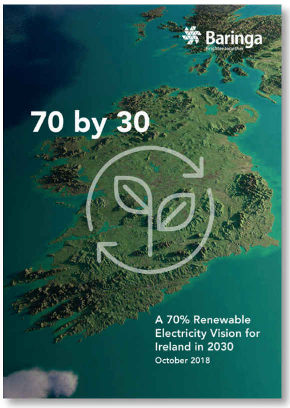
Our Energy Advisory practice offers a full spectrum of specialist advisory and analytical services, and transaction execution support. We bring together an unparalleled knowledge of the European energy sector and a quantitative approach built on evidence-based insight and powerful analytics. Our work is informed by knowledge of markets, regulation, assets, operations and capital, and in-depth insight into their interdependencies and the impact of their interactions. We provide our clients with a unique combination of flexibility, pragmatism, and intellectual rigour.

Ireland has been a key focus market for Baringa for many years, and we have developed an extensive knowledge of the Irish energy sector through a long track record of engagements with regulators, utilities, project developers, investors, and banks. We were heavily involved in the regulatory and operational aspects of the transition to I-SEM and DS3. We advise on asset investments, hedging and trading strategies, retail strategies, regulatory issues, market arrangements, modelling capabilities, and I-SEM business and IT preparation. We have acted as independent market advisors on the majority of the major energy sector transactions in recent years – on the buy-side, sell-side and for debt financing. Lenders frequently rely upon our analysis to make debt-finance decisions.

We have been voted as the leading management consulting firm in the Financial Times' UK Leading Management Consultants 2022 in the categories Energy, Utilities & the Environment, and Oil & Gas. We have been in the Top 10 for the last 15 years in the small, medium, as well as large category in the UK Best Workplaces™ list by Great Place to Work®. In 2022 they ranked us as #1 in the UK for wellbeing. We are a Top 50 for Women employer, and are recognised by Best Employers for Race.

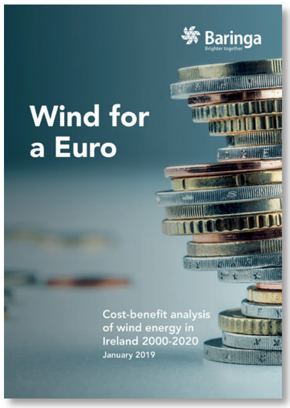
Find out more at baringa.com, or on LinkedIn and Twitter.

C.2 Our recent policy and market studies in Ireland



▸ *70 by 30*

Baringa carried out the landmark *70 by 30* study that established how 70% of Ireland's power consumption could be met by renewables by 2030, at zero net cost for end consumers. The findings of this study, published by Wind Energy Ireland in October 2018, ultimately became the primary driver behind the Irish Government target of 70% renewable electricity announced in the *Climate Action Plan 2019*.



▸ *Wind for a Euro*

Baringa led a thorough cost-benefit analysis of the 4 GW of wind capacity commissioned in Ireland from 2000 to 2020 in *Wind for a Euro*, published by Wind Energy Ireland in January 2019. The study concluded that the benefits brought by wind energy would be able to offset its costs – the net cost to end consumers of displacing 33 million tonnes of CO_2 emissions would be less than €1 per person per year.

▸ *Store, Respond and Save*

Published by Energy Storage Ireland in December 2019, *Store, Respond and Save* highlighted the vital role of zero-carbon system services in delivering a decarbonised Irish power sector and reducing costs incurred by end consumers. Emerging technologies such as dedicated battery storage and synchronous condensers were shown to save 2 million tonnes of CO_2 and €120m of end consumer costs in Ireland in 2030.

▸ *Endgame*

Baringa's *Endgame* report, published by Wind Energy Ireland in June 2021, sought to update the analysis behind *70 by 30*, and demonstrated that more of existing and proven technologies can enable Irish power sector targets of 80% renewable electricity and less than 2 million tonnes of CO_2 by 2030. These targets were ultimately adopted as official Government policy in the *Climate Action Plan 2021*.

GAME
CHANGER

energy storage IRELAND

Baringa