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The Missing Link

The value of energy storage in the All-Island market

JANUARY 2022

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CONTACT DETAILS

Alex Blanckley, CFA
alex.blanckley@afry.com
+44 (0)7808 589117

Andy Kelly
andy.kelly@afry.com
+44 (0)7824 145092

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1 Key messages

- **Energy storage is critical to the All-Island power market** because not only can it help solve the challenges facing the power system, but it can do so whilst also saving money for consumers.
- **Energy storage will play a critical role in ensuring system stability.** Elsewhere, the value of System Services / system stability to the All-Island market has been estimated at over €700 million[1] annually in 2030, with energy storage likely to play a key role in maintaining frequency, voltage and rotor angle stability as well as congestion management and system restoration.
- **A power system with 1.9GW of energy storage is a low regrets way to deliver net annual welfare benefits of €34 million over and above storage's contribution to improving system stability.** 1.9GW of energy storage could deliver gross benefits of €162 million annually with costs to storage developers offsetting this figure by €128 million annually.
- **Energy storage can reduce the amount of wasted renewable electricity by almost 800GWh** enough to power[2] all of the c.180,000[3] private households in Cork, Limerick, Galway, Waterford and Drogheda combined.
- **Additional energy storage has the potential to reduce the PSO Levy by €10-14 million annually in 2030[4]**. By reducing dispatch down, energy storage can reduce the amount of renewables capacity needed to meet 2030 targets and lower the cost of the PSO Levy.
- **Power sector emissions could fall by c.370kt annually in a scenario of 1.9GW of total energy storage** by displacing conventional thermal plant. This is almost equivalent to Waterford's current emissions[5] and saves c.€21 million[6] annually in 2030.

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[1] EC / EU SysFlex, Financial Implications of High Levels of Renewables on the European Power System, 11 March 2020.
[2] Assuming CRU's household consumption estimate of 4,200kWh / year.
[3] CSO, Census 2016 Small Area Population Statistics, accessed 24 August 2021.
[4] This assumes 80% of the 270MW onshore wind capacity that is not required to be built in the 1.9GW total storage scenario is located in Ireland (in line with Ireland's share of All-Island annual demand) and would have otherwise been supported by RESS at strike prices between €50/MWh and €60/MWh.
[5] RTE, Waterford aiming to become Ireland's first decarbonised city, 21 April 2021.
[6] Assuming a carbon price of €56.6/tCO_2.

- **Energy storage is able to provide a low-emissions source of firm capacity**, lowering the SEM's reliance on conventional gas-fired peaking plant. At current Capacity Market de-rating factors, 100MW of 6 hour storage can offset c.80MW of OCGT capacity.
- **6 hour storage currently appears to provide the best 'bang-for-buck' for society**. Weather conditions across the island of Ireland mean wind output is either very high or very low for around half of the year, with periods of high or low wind lasting a little under 20 hours on average. Longer-duration storage may be able to provide greater value but current Capacity Market de-rating factors limit the security of supply benefits of longer-duration storage.
- **Several barriers to the development of storage, particularly longer-duration storage, in the SEM have been identified:** (1) uncertainty over the System Services regulatory framework; (2) a lack of a level playing field for energy storage in existing support mechanisms; (3) a grid connection policy that implicitly disadvantages energy storage; (4) a transmission network charging design that does not incentivise flexibility; (5) a lack of policy emphasis on long-duration storage; and (6) a complex market structure that is not conducive to streamlined decision making.
- **These barriers prevent energy storage from competing for the value it provides to society.** As things stand, there are significant risks that the value provided by energy storage (and particularly long-duration storage), will not be reflected in the market designs of the future.
- **Best practice should allow for storage to compete on a level playing field for the value that it brings**. Currently, storage is not able to compete for this value and it should not be explicitly disadvantaged because of: legacy choices regarding the definition of market actors; market design; policy support; network charging; or taxation policies.

Exhibit 1.1 – Recommendations

Topic	Aim	Objective	Stakeholders	Timing	IESA role
Policy	Develop comprehensive policy for energy storage	Recognise the critical role of energy storage in accommodating high levels of non-synchronous renewable generation	EirGrid / SONI, CRU, DECC	2021-2022	Engage with all relevant stakeholders
CRM	Address inconsistencies in the design of the CRM	Ensure that storage with durations >6hr receive de-rating factors similar to DSUs >6hr	SEMO	2021	Submit Capacity Market Modification Proposal
ECP	Remove implicit disadvantage from ECP	Introduce a minimum number of connection offers for storage	CRU	Before September 2022	Engage with CRU in relation to ECP-2.3
RESS	Clarify rules for hybrids	(1) Retain ability to give hybrids a different ECF to the underlying RESS technology (2) Introduce additional hybrid models	DECC	August 2021	Respond to DECC's RESS-2 consultation
Flexibility incentives	Increase incentives for flexibility	Comprehensive review of incentives for flexibility, including (but not limited to): (1) temporal variation in transmission network charging (2) distinguishing between flexible and inflexible consumption with respect to PSO Levy charges (3) novel System Services products that allow for better use to be made of storage's capability to reduce congestion	EirGrid / SONI, ESB / NIE Networks, SEMC	2021-2022	Engage with all relevant stakeholders

2 Introduction

2.1 Purpose of the study

AFRY Management Consulting (AFRY) has been engaged by the Irish Energy Storage Association (IESA) to provide an independent analysis of the value of energy storage by exploring a range of alternative future outcomes of the Irish Single Electricity Market (SEM). This study specifically explores the impact on societal welfare (and a range of other key metrics) of different levels of storage capacity, with key assumptions on demand and fuel carbon prices taken from reputable third party sources. We have also reviewed barriers to storage deployment and regulatory / policy / market design 'best practice'.

2.2 Climate and renewables ambition

Both Ireland and Northern Ireland have progressive climate ambitions with Ireland targeting a net-zero emissions economy by 2050[7], and Northern Ireland currently consulting on whether to target net zero carbon energy by 2050[8]. To achieve these ambitions, it is clear that profound changes to the power sector will be required, with renewable energy playing an increasingly critical role. To that end, Ireland is targeting 70% of electricity demand being satisfied by renewable generation by 2030[9], whilst Northern Ireland is consulting on adopting a similar target[8].

2.3 Challenges facing the system

If the 70% renewables target is to be achieved, the All-Island power sector will have to undergo profound change. At the heart of this need for change are several technical challenges related to maintaining frequency, voltage and rotor angle stability, congestion management and system restoration amongst others. It is these challenges that underpin many of the more widely reported concerns, such as:

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[7] Government of Ireland, Climate Action and Low Carbon Development (Amendment) Bill 2021, 23 March 2021.
[8] DFE, Energy Strategy for Northern Ireland – consultation on policy options, 31 March 2021.
[9] Government of Ireland, Climate Action Plan 2019, 17 Jun 2019.

- how to keep renewables curtailment to manageable levels (which in turn lowers the cost of renewables to consumers and decarbonises the power sector more rapidly and cheaply);
- how to improve the balance between (historically inflexible) power demand and (increasingly volatile) power generation (without which there can be load loss or even complete black outs);
- how to ensure there is sufficient firm capacity to ensure security of supply particularly at times of high demand and / or low renewables output; or
- how to reduce the number of large thermal plants that must be kept on to maintain system stability (which affects wind curtailment and increases emissions).

2.4 The role of energy storage

Energy storage has a critical role to play as the power system transitions to ever higher levels of intermittent renewable generation, because it is able to address many of the challenges being faced. At a very high level, the ability to store and release energy increases the flexibility of the power system. But it is not just additional flexibility that energy storage can provide:

- Synchronous forms of storage are able to store kinetic energy and provide inertia which slows the rate of change of frequency (RoCoF) when a fault occurs, giving the system more time to bring on generation reserves.
- Many storage technologies are able to respond to a fault very rapidly, either generating or absorbing active power to stabilise grid frequency.
- Many energy storage technologies are capable of generating or absorbing reactive power which helps to maintain voltage stability.
- Synchronous forms of energy storage can help maintain rotor angle stability by providing synchronising torque and damping torque.
- Longer-duration forms of storage sited in appropriate locations are able to reduce network congestion by absorbing excess generation and injecting / or avoiding consumption at times when demand is high. Longer-duration storage is also able to provide ramping reserve to help mitigate against increasing energy imbalance volumes.

A summary of several of the more advanced energy storage technologies and their capabilities is shown in Exhibit 2.1.

Exhibit 2.1 – Overview of selected energy storage technologies and their potential capabilities

Name	Description	Capability						
		Load shifting	Synchronous inertia	Frequency response	Voltage stability	Rotor angle stability[1]	Congestion	Ramping
Batteries	When a battery is charged, it causes electrons to flow from the battery's anode to its cathode where they build up storing electricity. When discharged, the flow is reversed resulting in the generation of electricity.	✓	✗	✓	✓	✗	✓	✓
CAES (Compressed Air Energy Storage)	Electricity is used to compress air typically into a cavern. When the air is released, it spins a turbine connected to a generator to produce electricity.	✓	✓	✓	✓	✓	✓	✓
LAES (Liquid Air Energy Storage)	Electricity is used to liquefy air which is then stored in insulated tanks. When the air is warmed it expands and spins a turbine connected to a generator to produce electricity.	✓	✓	✓	✓	✓	✓	✓
Pumped storage	Electricity is stored as gravitational potential energy by pumping water from a low elevation reservoir to a higher elevation reservoir. This energy is released by allowing the water to flow back down to the lower reservoir where it spins a turbine connected to a generator.	✓	✓	✓	✓	✓	✓	✓
Synchronous condensers	Synchronous condensers are essentially a generator that is not connected to a turbine. Electrical energy is stored as kinetic energy in the form of a rotating mass that is synchronised to the grid, with this energy released as inertia when grid frequency fluctuates.	✗	✓	✗	✓	✓	✗	✗
Thermal storage	Electrical energy is used to heat a material (e.g. molten salt or concrete), with the stored energy released as the material is cooled. The released energy can be converted back to electrical energy or be used as thermal energy. This can be of particular interest to industrial sites that have significant heat demand.	✓	✓[2]	✓[2]	✓[2]	✓[2]	✓	✓

1. Rotor angle stability covers synchronising and damping torque.
2. Depending on unit configuration.

There are of course, other technological solutions that will be required en route to achieving 2030 renewables targets and the longer-term transition to net zero, but energy storage has the advantage of being a fairly mature group of technologies as well as being increasingly economically competitive.

As we show later in this study, energy storage can not only help solve the challenges facing the All-Island power system, but it can do so whilst also saving money for consumers.

2.5 Structure of this report

The rest of this report is structured as follows:

- Chapter 3 outlines the approach used in evaluating the benefits of storage and how much storage might be needed;
- Chapter 4 presents the results of this welfare analysis;
- Chapter 5 discusses some of the barriers to additional storage development;
- Chapter 6 provides an overview of storage 'best practice'; and
- Chapter 7 contains the recommendations arising from this study.

Further details regarding how the power market modelling has been carried out and the key inputs used and resulting outputs can be found in Annex A, Annex B and Annex C.

3 Methodology

To determine the value of energy storage in Ireland we have performed several simulations of the All-Island power market that allow us to quantify the differences in societal welfare between different configurations of the All-Island power system in 2030.

More specifically, we have posited a Reference scenario as well as five Alternative scenarios that differ only in the amount of energy storage, onshore wind and thermal peaking capacity (i.e. OCGTs) in each scenario. All other inputs (e.g. demand, fuel prices, carbon prices, etc.) are the same in all scenarios. Consequently, any differences in welfare between the scenarios can be attributed directly to the changes in energy storage / onshore wind / peaking thermal capacity.

The rationale for changing energy storage, onshore wind and peaking thermal capacity (as opposed to simply changing the amount of energy storage) is based on the hypothesis that by increasing the amount of energy storage in the generation mix, the system will be able to:

- make more efficient use of renewables capacity (e.g. by reducing dispatch down) and therefore require fewer MW of renewables to reach a 70% RES-E penetration target; and
- require less thermal peaking capacity due to energy storage being able to provide firm capacity.

3.1 Definition of annual 'net welfare'

We define the annual net welfare of an Alternative scenario as the sum of the differences between the Alternative scenario and the Reference scenario with respect to three key categories of annual cost (further details are provided in Box 1):

- electricity production costs[10];
- energy balancing and redispatch costs; and
- capital[11] and operating expenditure (CAPEX and OPEX) on energy storage / renewables / thermal peaking capacity.

[10] Differences in production costs are the key driver of differences in typical assessments of socio-economic welfare (see for example the underlying methodology and cost-benefit analysis results of ENTSO-E's TYNDP 2020).

An illustration of the concept[12] is shown in Exhibit 3.1 and Exhibit 3.2. For the avoidance of doubt, any reference to annual net welfare below describes the difference between one of the Alternative scenarios and the Reference scenario with respect to the year 2030. Values are quoted in millions of euro at real 2020 prices.

Exhibit 3.1 – Cost categories that have been assessed when calculating annual Net Welfare

Net Welfare is the difference in production costs, energy balancing and redispatch costs and annualised CAPEX and OPEX between an Alternative scenario and Reference

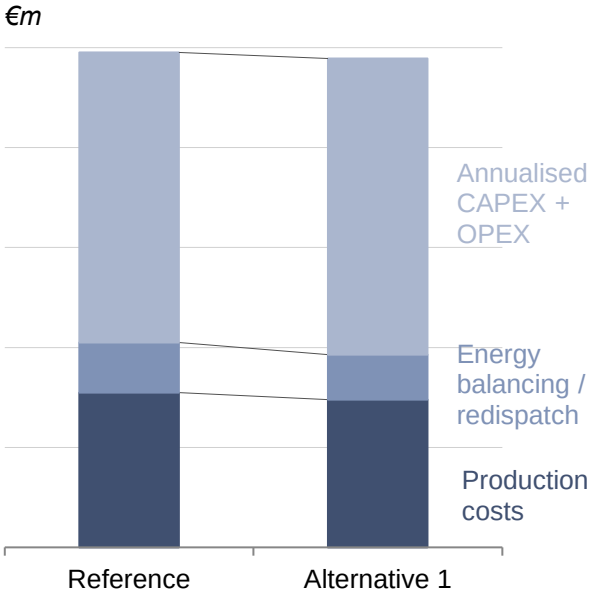
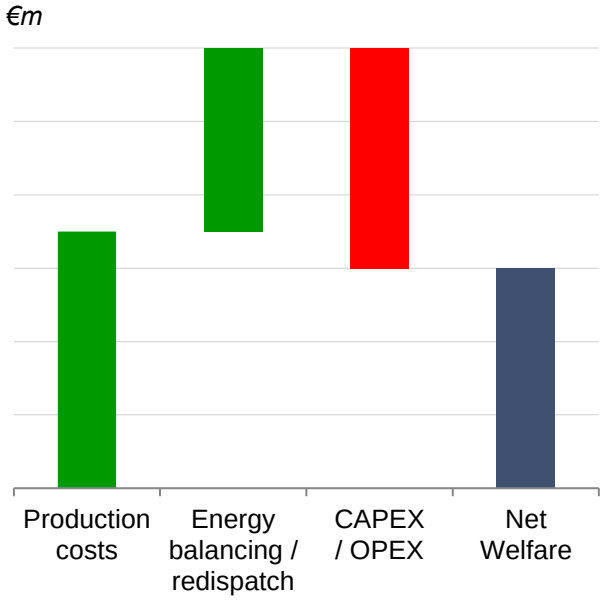


Exhibit 3.2 – Drivers of differences in annual Net Welfare

By examining the differences in the various categories of costs, we can determine where welfare is increased (in green) or reduced (in red)



3.1.1 The value of system stability

As described previously, energy storage will play a key role in ensuring the network is able to handle high levels of intermittent renewable generation. The value of system stability has been evaluated elsewhere[13] at up to €711 million annually. In this study, we have not attempted to put a value on system stability nor have we tried to quantify the share of value provided by energy storage. However, it is commonly agreed that deployment of various storage technologies will play a critical role in delivering this system stability.

[11] Capital expenditure (CAPEX) is annualised over the economic lifetime of a project at an assumed hurdle rate.
[12] Note that an alternative, but equivalent approach would be to quantify all end costs to consumers (e.g. the cost of satisfying power demand, the capacity market, RESS, REFIT, etc.).
[13] EC / EU SysFlex, Financial Implications of High Levels of Renewables on the European Power System, 11 March 2020.

Box 1 The cost of power

When we talk about production costs, we are referring to the costs of producing the electricity that is scheduled to be generated in the Day Ahead Market. Typically, these costs comprise: fuel costs; carbon costs; and a range of other costs (e.g. variable maintenance costs, the cost of starting power plants, and so on). Importantly, this generation schedule is determined assuming there are no network constraints (of which there are several), and so it does not reflect the outturn generation mix.

In order to get to the outturn generation mix, we must subsequently adjust the Day Ahead schedule to reflect the constraints on the power network. This involves increasing the output of some power plants and decreasing the output of others. The costs associated with doing this are captured in our category of energy balancing and redispatch costs. For the avoidance of doubt, these are also production costs, they are categorised separately.

3.2 The Reference scenario

The Reference scenario represents one vision of the All-Island power system in 2030, where:

- All-Island power demand reaches c.53TWh[14], driven by an increasing number of data centres, one million EV's on the road and 700,000 heat pumps installed.
- Gas prices at the UK National Balancing Point reach 58p/therm[15].
- Carbon prices (EU ETS EUAs) reach €57/tCO_2[15].
- Renewables penetration across the SEM is 70%, with 8.5GW of onshore wind, 3.7GW of offshore wind and 2.1GW of solar PV.
- EirGrid successfully manages to raise the System Non-Synchronous Penetration (SNSP) limit to 95%, with significantly fewer system-wide constraints than today.
- There is 463MW of short-duration (i.e. c.0.5hr) battery capacity reflecting currently operational capacity as well as the 'power' batteries that are anticipated to come online later in 2021 or under the DS3 Volume Capped programme.
- Sufficient new build thermal capacity (1.2GW of OCGTs) is added to the system to ensure demand can be met.
- Interconnection capacity increases following the completion of the 500MW Greenlink and 700MW Celtic interconnectors with Great Britain (GB) and France respectively. This increases the size of the largest loss and with it the amount of operating reserves required.

Additional details on the inputs into the modelling exercise can be found in Annex B.

[14] EirGrid / SONI, Shaping Our Electricity Future Technical Report, 8 March 2021.
[15] National Grid ESO, Future Energy Scenarios 2020, July 2020.

3.3 Alternative scenarios

In the alternative scenarios the only changes vs. the Reference scenario are:

- increased levels of energy storage;
- reduced amounts of onshore wind capacity[16]; and
- reduced amounts of peaking thermal capacity.

The first of the Alternative scenarios is one where we have increased the amount of energy storage capacity to include all of the batteries that have successfully secured Capacity Remuneration Mechanism (CRM) contracts (an additional 363MW vs. Reference). Thereafter we have added a further 500MW, 750MW, 1GW and 1.25GW of storage capacity in our scenarios. The specific levels of energy storage, onshore wind and peaking thermal capacity is indicated below in Exhibit 3.3.

Exhibit 3.3 – 2030 installed capacity of energy storage, onshore wind and peaking thermal capacity by scenario (MW)

As SEM-wide energy storage capacity increases, the amount of onshore wind and peaking thermal capacity is reduced

		Alternative Scenarios				
	Reference	Contracted batteries	1.6GW storage	1.9GW storage	2.1GW storage	2.4GW storage
Energy storage	755	1,118	1,618	1,868	2,118	2,368
Turlough Hill PS	*292*	*292*	*292*	*292*	*292*	*292*
0.5hr storage	*463*	*463*	*463*	*463*	*463*	*463*
1hr storage	*0*	*79*	*79*	*79*	*79*	*79*
2hr storage	*0*	*200*	*200*	*200*	*200*	*200*
4hr storage	*0*	*84*	*334*	*84*	*84*	*84*
6hr storage	*0*	*0*	*250*	*750*	*1,000*	*1,250*
Onshore wind	8,490	8,440	8,308	8,220	8,178	8,126
OCGT	2,046	1,919	1,553	1,316	1,120	922

Note: 0.5hr storage is assumed to participate in the Day Ahead and Balancing Markets if it has a CRM contract.

For the purposes of the modelling study we have assumed that the additional 4 hour and 6 hour energy storage in the 1.6/1.9/2.1/2.4GW total storage scenarios are Li-ion batteries with 85% round trip efficiency. This is a modelling simplification and is primarily driven by the availability of reliable data on current costs for Li-ion batteries and a loose 'consensus' regarding the trajectory of future costs for Li-ion batteries. It is important to add that while our analysis suggests Li-ion batteries are likely to be a cost competitive form of energy storage at storage durations of up to 6 hours in 2030, there are other forms of 4hr and 6hr storage that may be deployed instead.

[16] We have chosen to reduce onshore wind capacity because we expect it to have the lowest levelised cost of energy (LCOE) and thus provide a conservative basis for our analysis.

Ultimately, this study is relatively insensitive to the choice of technology largely because we assume that the network is significantly less constrained in the future (as a result of a successful System Services program) in all scenarios. Of greater importance is the overall impact of our cost and efficiency assumptions.

It is important to note that we have arrived at the onshore wind and OCGT capacities above via an iterative process that has removed wind and OCGT capacity until renewables penetration reaches 70.0% (after accounting for dispatch down) and there is sufficient firm capacity to ensure no loss of load in a 1-in-5 peak demand year. Our assessment of capacity margins reflects de-rating factors as published for the 2024/25 T-4 Capacity Auction[17].

3.4 Power market modelling

In order to calculate the Net Welfare of the Alternative scenarios, it is necessary to simulate the dispatch and redispatch of the SEM in 2030. We have performed this using our own power market model, known as BID3. In short, BID3 is a least-cost optimisation model that can be used to simulate the hourly dispatch and redispatch of the SEM. It has been used to support a wide range of our clients including TSOs, regulators, utilities and investors amongst others. For further details regarding the modelling, please see Annex A.

[17] EirGrid / SONI, Capacity Market – Final Auction Information Pack FAIP2425T-4, 8 December 2020.

4 Benefits of energy storage

In summary, our analysis demonstrates that energy storage can provide significant value to society by making better use of low carbon renewables generation, whilst reducing the need for high emissions conventional peaking capacity. In comparison with the Reference scenario, and taking the Alternative scenario where there is 1.9GW of storage on the system in 2030, we observe:

Additional energy storage could save the PSO Levy €40-60m per year

- an overall increase in Net Welfare of €34 million;
- €10-14 million annual reduction in the PSO Levy[18];
- 370,000 tonnes fewer carbon emissions from the power sector; as well as
- greater utilisation of the renewables fleet and interconnectors and less reliance on conventional thermal peakers.

4.1 Net welfare benefit

Our simulations suggest increasing the amount of energy storage in the SEM can provide significant net benefits to society (Exhibit 4.1). The results suggest that society continues to benefit until there is around 1.9GW of energy storage on the system. Thereafter, although net welfare benefits remain significant, they begin to fall, as the cost of additional storage more than outweighs the additional benefits arising.

Our analysis is dependent on our assumptions for CAPEX / OPEX of onshore wind, OCGTs and storage. Although we believe our assumptions are both reasonable and conservative (see Annex B.4 for details), we have nevertheless investigated how the results would look if we have overestimated the future cost of onshore wind and OCGTs and underestimated the cost of storage. The results of this analysis are shown in Exhibit 4.2.

Increasing energy storage capacity to 1.9GW is a low regrets option

At levels of storage capacity up to 2.4GW, we see annual net welfare benefits even if wind / OCGT costs are overestimated and storage costs in 2030 are underestimated. There is a noticeable drop off in the most punitive sensitivity when total storage capacity is increased to above 1.9GW,

[18] This assumes 80% of the 270MW onshore wind capacity that is not required to be built in the 1.9GW total storage scenario is located in Ireland (in line with Ireland's share of All-Island annual demand) and would have otherwise been supported by RESS at strike prices between €45/MWh and €55/MWh.

suggesting the scenario with 1.9GW of total energy storage is a low regrets option for the SEM.

Exhibit 4.1 – 2030 annual net welfare benefit vs. Reference scenario (€ millions, real 2020 prices)

Annual net welfare in 2030 increases as the amount of energy storage in the All-Island market is increased, up to around 1.9GW of storage, after which benefits plateau

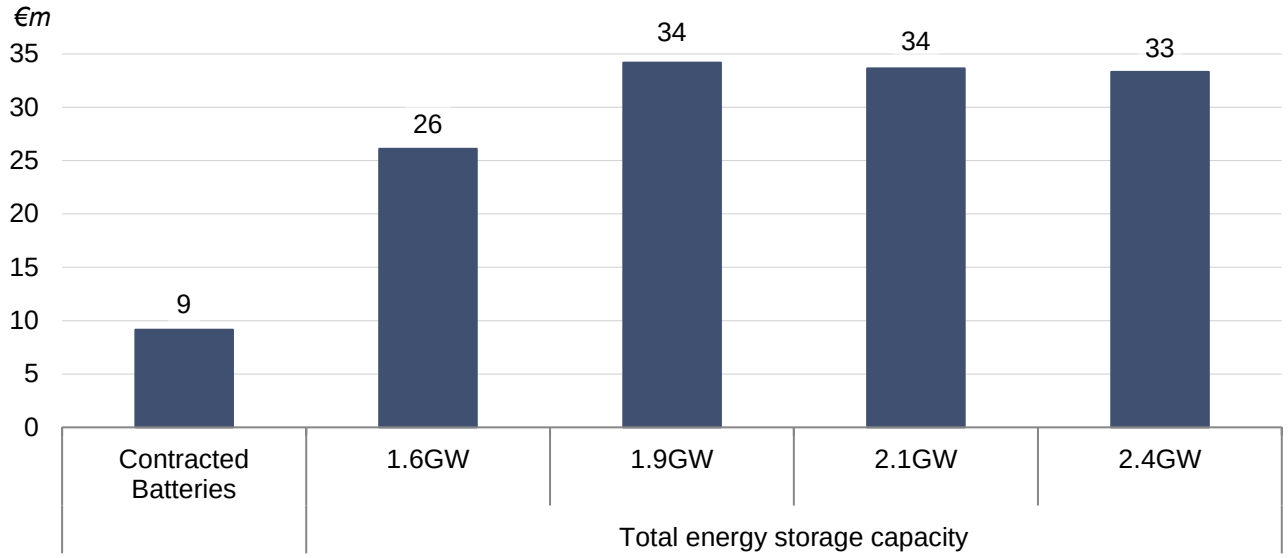
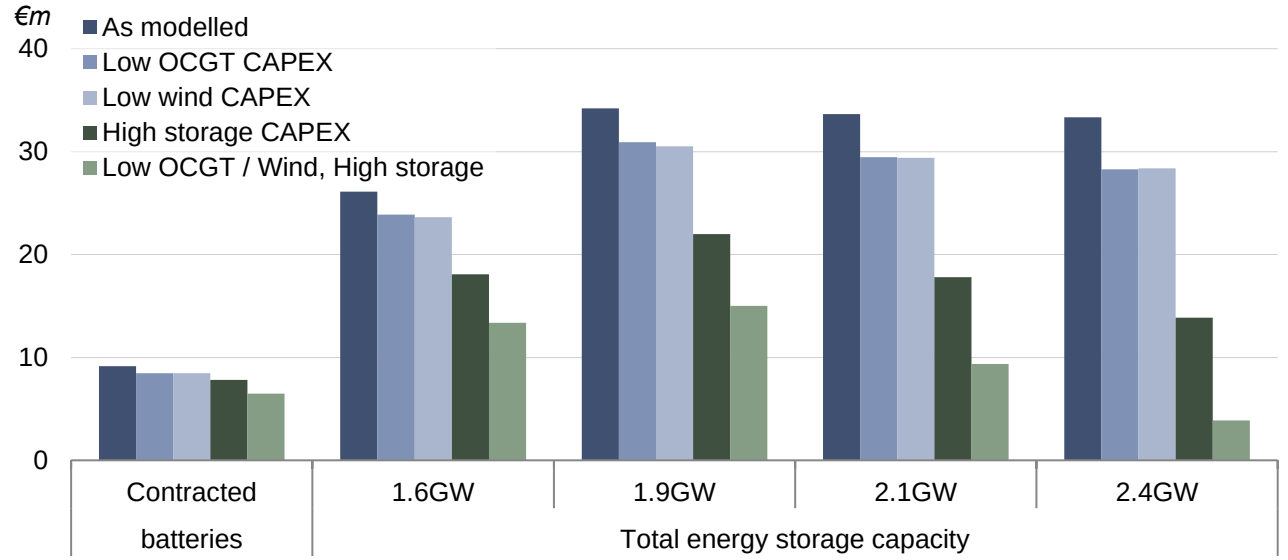


Exhibit 4.2 – Sensitivity of 2030 annual net welfare benefit (vs. Reference scenario) to CAPEX assumptions (€ millions, real 2020 prices)

Even if onshore wind / OCGT costs have been overestimated and storage costs underestimated, a system with 1.9GW of total storage increases societal welfare



Notes:
1. Each column shows a different sensitivity under each of the five modelled scenarios.
2. Low OCGT CAPEX assumes costs are in line with a frame OCGT of €500/kW (As modelled assumes a €550/kW cost, reflecting the average cost of a frame OCGT and an aeroderivative OCGT).
3. Low wind CAPEX assumes a 20% reduction on 2020 costs of €1,150/kW (As modelled assumes a 15% reduction on typical 2020 costs of €1,275/kW).
4. High storage CAPEX assumes 15-20% declines vs. 2020 (As modelled assumes 30-35% cost reductions).

4.2 Drivers of Net Welfare benefits

There are two fundamental drivers of the value of energy storage:

- energy storage makes better use of the renewables fleet; and
- it reduces the need for carbon-emitting conventional peaking capacity.

These two fundamental benefits manifest themselves in several ways in our simulations, including:

- **reduced dispatch down** which improves the capacity factor of renewables generation leading to lower costs;
- **a smaller conventional peaking fleet** which results in a lower-emissions source of back-up power; and
- **lower production costs and carbon emissions** resulting from the displacement of thermal generation.

We discuss these in greater detail below.

4.2.1 Reduced dispatch down

If 70% renewables penetration is reached, there will be many times during the year when the output of the renewables fleet exceeds demand as well as what the network can handle. During these periods, renewables generation is dispatched down and effectively wasted. If energy storage levels are increased, the amount of wasted renewables generation will be reduced (Exhibit 4.3). This in turn can result in one of two broad outcomes:

- either (as modelled in this study) fewer MW of renewable generation capacity are required to meet the 70% renewables target (Exhibit 4.4), which in turn could significantly reduce PSO Levy costs (see Exhibit 4.5 and Box 2 for additional details) as well as energy balancing and redispatch costs (Exhibit 4.6); or
- there will be even more renewables output resulting in greater decarbonising of the power sector and reduced wholesale power costs.

Box 2 PSO Levy cost reduction

To quantify the potential impact on the PSO Levy requires assumptions for: (1) the amount of wind capacity that would have been supported by RESS had it been built; (2) the strike price of this capacity; and (3) hourly Day Ahead prices in 2030.

For wind capacity, we have assumed that 80% of the 270MW of avoided onshore wind is located in Ireland (in line with Ireland's share of All-Island demand) and that all of this capacity would have been supported by RESS. Strike prices are assumed to range between €50/MWh and €60/MWh. Hourly Day Ahead power prices are an output of the modelling study. By comparing hourly day ahead prices to the assumed strike prices for the c.215MW of avoided onshore wind supported by RESS, we can calculate the potential savings to the PSO Levy.

Exhibit 4.3 – 2030 additional renewables generation resulting from reduced dispatch down vs. Reference (GWh)

More storage reduces dispatch down resulting in higher renewables generation

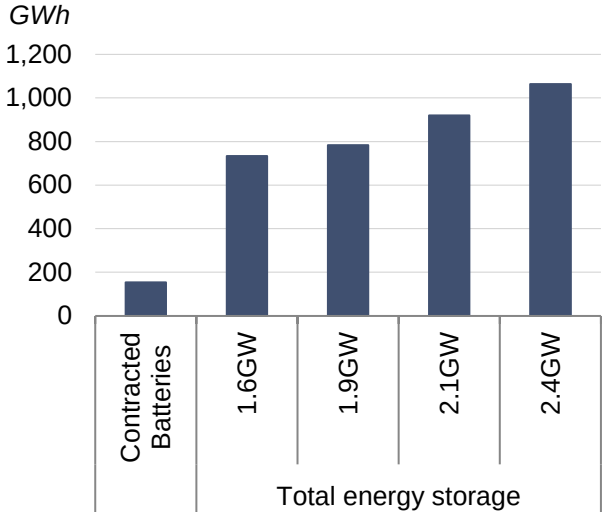


Exhibit 4.4 – 2030 onshore wind capacity not required vs. Reference (MW)

Higher capacity factors → fewer MW required to generate a given amount of output

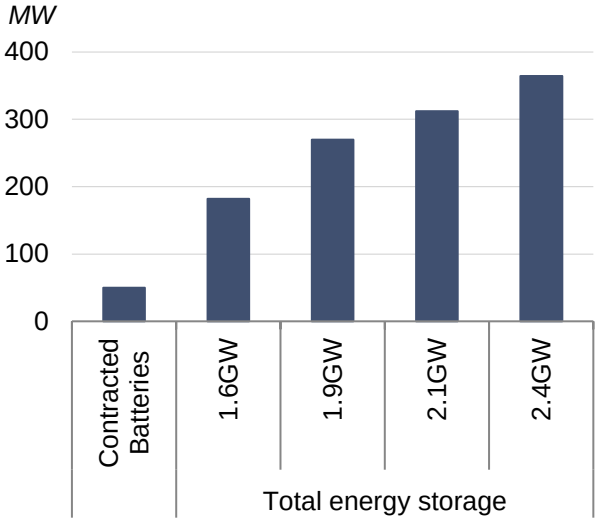
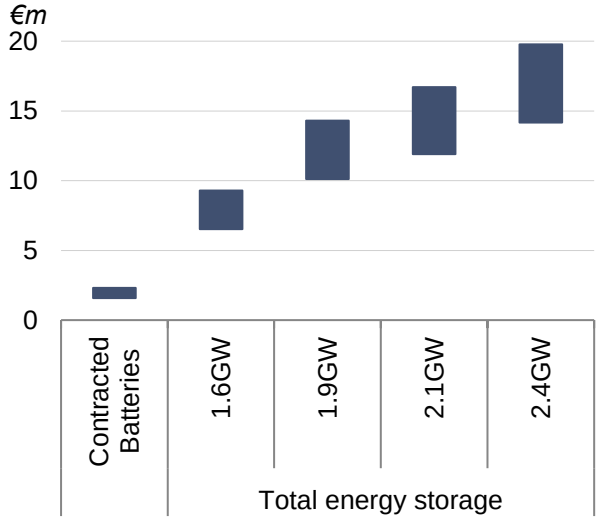


Exhibit 4.5 – Range of potential 2030 annual PSO Levy reduction vs. Reference (€ millions, real 2020 prices)

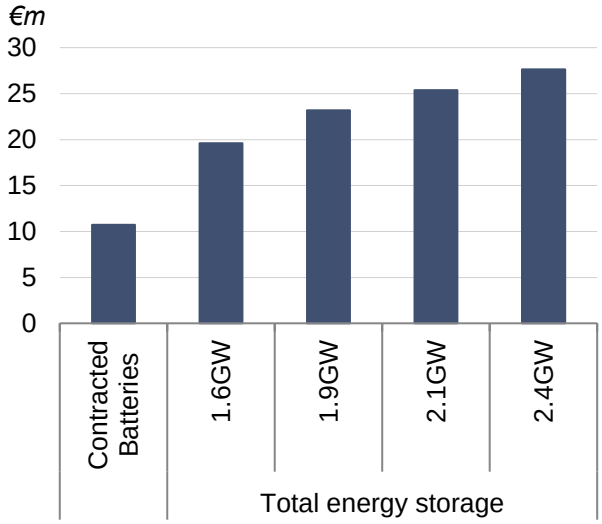
Fewer MW of onshore wind could lower PSO Levy costs significantly



Notes: Assumes 80% of onshore wind not required to be built is located in Ireland and would have otherwise been supported by RESS at strike prices between €50/MWh and €60/MWh.

Exhibit 4.6 – 2030 annual energy balancing and redispatch cost benefit vs. Reference (€ millions, real 2020 prices)

Lower dispatch down, a smaller wind fleet and storage providing a low cost source of energy balancing / redispatch → lower costs



4.2.2 Smaller fleet of thermal peakers

Energy storage, particularly longer-duration storage, is able to provide firm capacity, resulting in less need for conventional peaking plant (Exhibit 4.7). Ultimately, this results in reduced carbon emissions (Exhibit 4.8) worth around €21 million[19] annually in the 1.9GW storage scenario, and typically lower production costs as the cost of charging for energy storage is lower than the cost of natural gas and carbon for a thermal peaker.

Exhibit 4.7 – 2030 OCGT capacity not required vs. Reference (MW)

Adding energy storage to the capacity mix results in fewer MW of thermal peakers being required

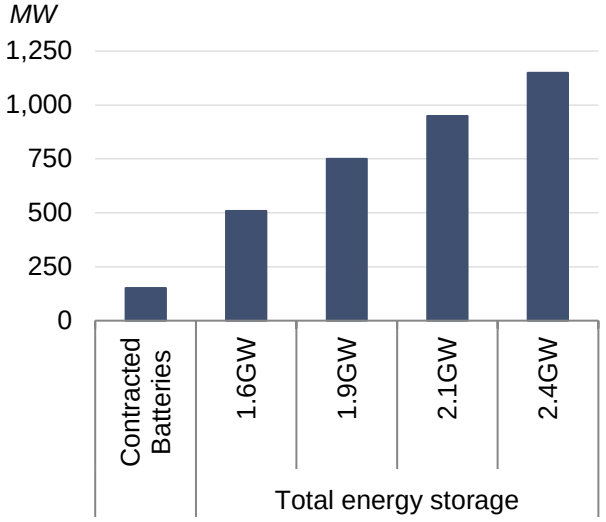
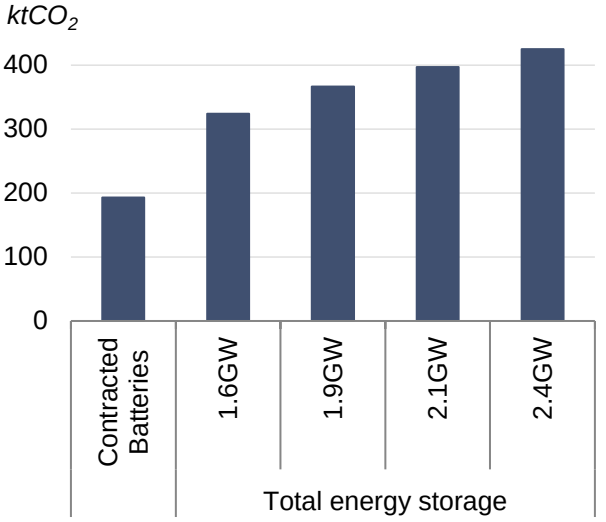


Exhibit 4.8 – 2030 annual carbon emissions benefit vs. Reference (kt CO_2)

As the amount of energy storage is increased, carbon emissions fall, despite there being no additional renewables output



Note: Emissions are calculated on the basis of outturn generation.

4.2.3 Lower production costs and carbon emissions

Our simulations reveal that even if renewables penetration is kept constant at 70% (i.e. there isn't any additional low cost wind or solar generation), additional energy storage lowers electricity production costs.

More specifically, when additional storage is introduced, the amount of conventional thermal generation falls (Exhibit 4.9), with imports to the SEM increasing. In this study, the SEM is a net importer largely for the following reasons:

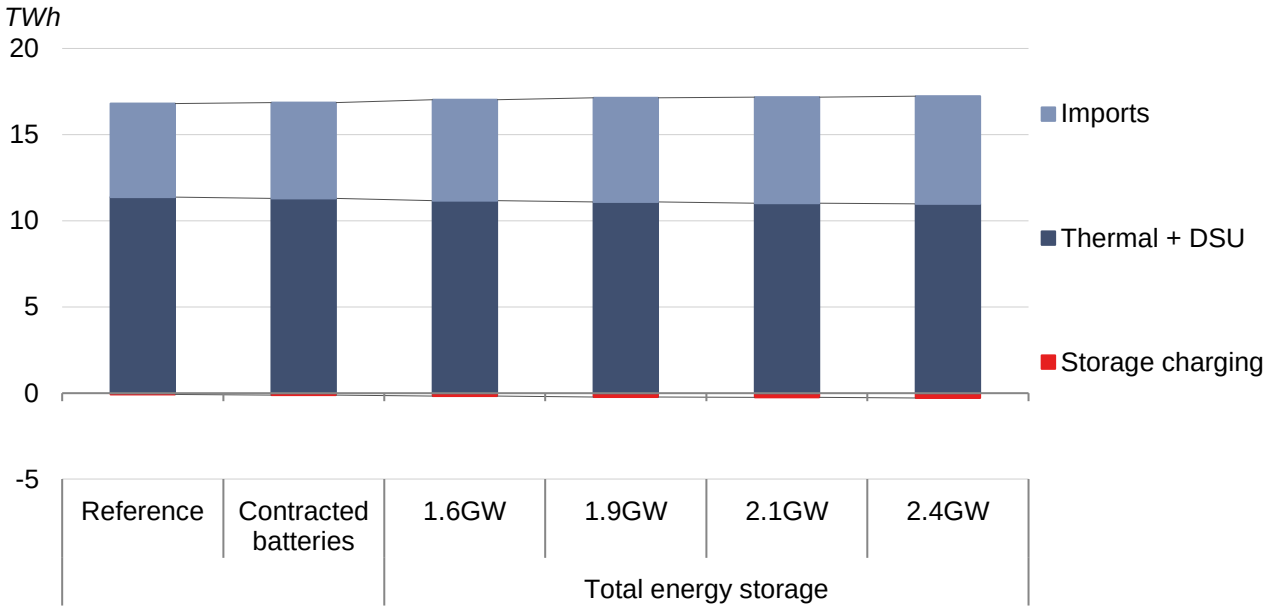
- we assume significant amounts of low marginal cost renewables generation is developed in Great Britain (GB) in the next decade, driven by ambitious 2030 targets (specifically offshore wind)[20];

[19] Assuming a carbon price of €56.6/tCO_2.
[20] We have taken a conservative approach to offshore wind uptake in GB and assume 'only' 33GW of offshore wind is on the system in 2030 vs. a target of 40GW.

- the continued presence of a large (60GW) nuclear fleet in France that generates at low cost; and
- high variable costs of gas generation in the SEM, driven by an increasing tendency for gas capacity costs to be bid into the wholesale market as renewables generation increases and thermal load factors fall (see Box 3 for additional details).

Exhibit 4.9 – 2030 thermal generation, imports and net storage by scenario (TWh)

As storage capacity is increased, the amount of thermal generation falls and imports increase



The reason imports rise as storage increases is largely related to our choice of keeping renewables penetration constant across scenarios. This means that rather than charging using increasing amounts of cheap renewable generation in the SEM, energy storage charges using cheap interconnector imports instead. When we have tested scenarios where renewables penetration was allowed to rise above 70.0%, we found thermal generation was displaced by renewables with interconnection playing a diminished role. Consequently, we believe the finding of reduced production costs and carbon emissions is robust.

The displacement of relatively high cost thermal generation by imports results in lower production costs (Exhibit 4.10) and carbon emissions (see Exhibit 4.8 above).

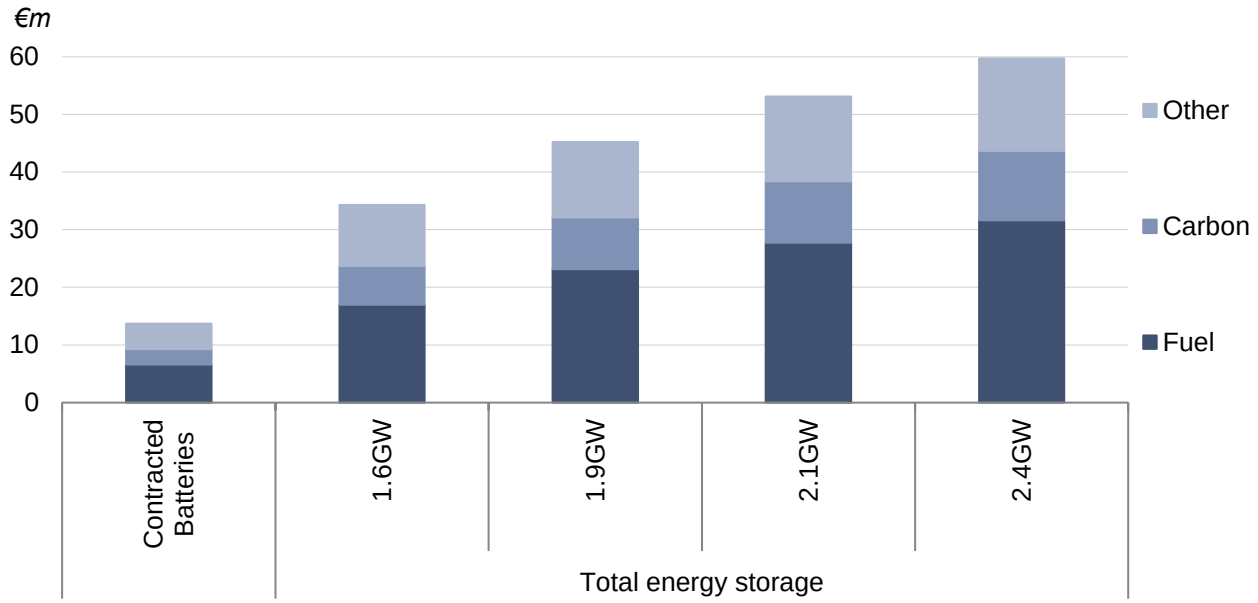
Box 3 Gas network costs in the SEM

Under the current tariff structure, gas generators have the option of purchasing gas capacity on a daily basis. We have observed that low-merit CCGTs and peaking plant typically take advantage of this and submit bids in the Day Ahead Market that are higher than bids of high-merit plant by approximately the amount of the cost of daily gas capacity.

Assuming the current tariff structure does not change (as we have done in this study), we would expect an increasing conventional gas-fired capacity to reflect the cost of gas capacity in their Day Ahead Market bids as renewables penetration rises and load factors fall.

Exhibit 4.10 – 2030 annual production cost benefit vs. Reference (€ millions, real 2020 prices)

With relatively expensive thermal generation replaced with cheaper imports, production costs fall when more storage is added to the system



Note: Other costs include: some maintenance costs; start-up costs; and 'no load' costs.

4.3 What type of storage provides the highest benefits?

The analysis presented above illustrates that an All-Island power system with 1.9GW of storage could bring significant benefits, even once the costs of developing all of that storage are factored in. A further issue to be considered is the type of storage that should be built.

In short, our simulations suggest that once the batteries with capacity contracts have been developed, the greatest welfare gains are associated with the development of 6 hour duration storage. That is not to say that storage of other durations are not valuable to society, just that they do not provide the best trade off of costs and benefits.

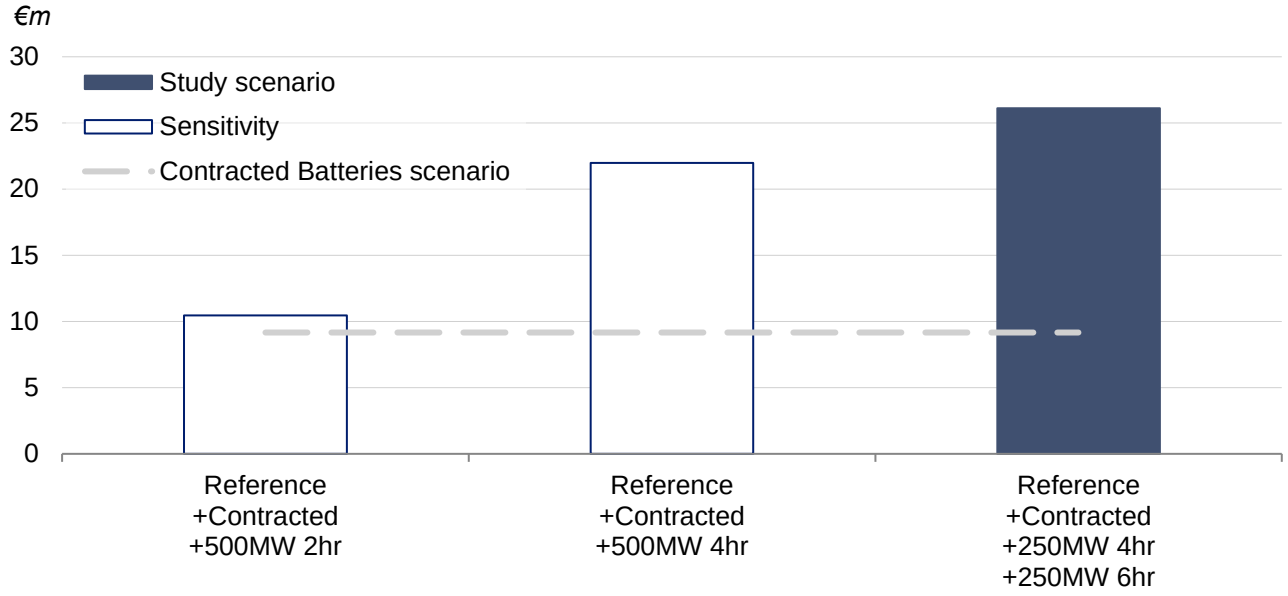
4.3.1 The role of 2 hour storage

A notable finding of our analysis is that 2 hour storage has only a small role to play and that once the 2 hour batteries that have capacity contracts are developed, the benefits of further 2 hour storage does not outweigh the additional cost.

Exhibit 4.11 shows the net welfare benefits of several variations of the 1.6GW total storage scenario[21] (i.e. Contracted Batteries + 500MW of additional storage) in comparison to the Reference scenario. When 500MW of 2 hour storage is added on top of the batteries with capacity market contracts, 2030 annual net welfare increases by around €1 million (as shown by the height of the left most column compared to the dashed line). When 500MW of additional 4 hour or a mixture of 4 hour / 6 hour storage is added, the increase in welfare is an order of magnitude greater. Interestingly, this analysis suggests that 6 hour storage provides greater value than 4 hour storage.

Exhibit 4.11 – 2030 annual Net Welfare benefits vs. Reference in the 1.6GW total storage scenario under different mixes of storage duration (€ millions, real 2020 prices)

Additional 2 hour storage provides little incremental value to the system

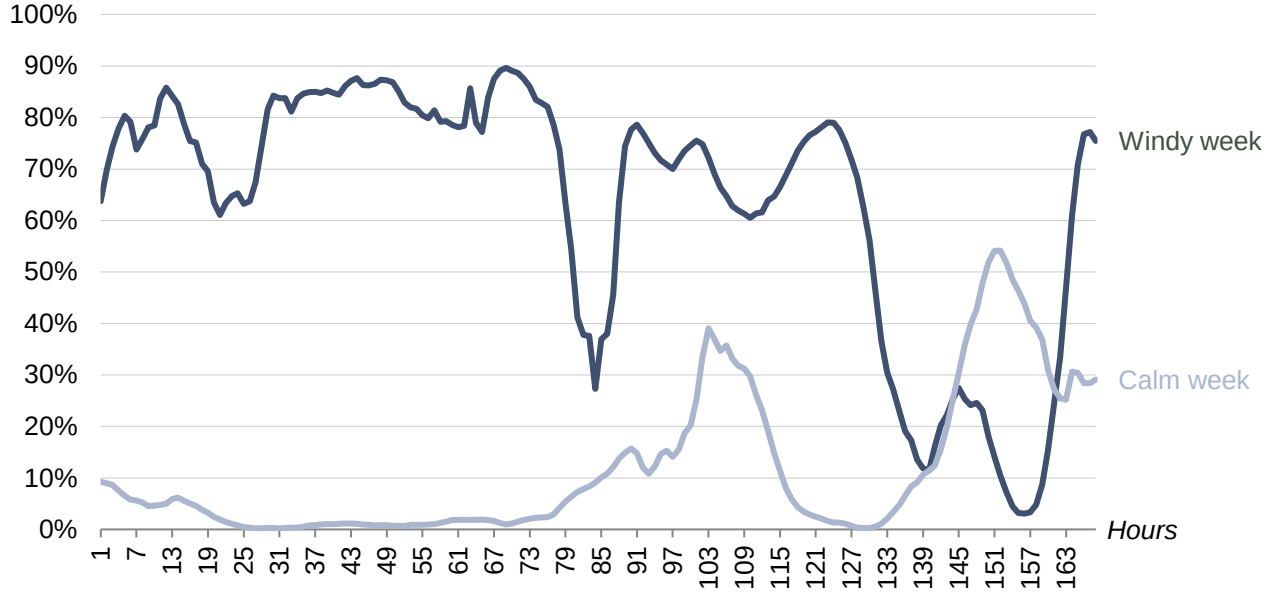


Given the weather conditions in Ireland and Northern Ireland, this finding is perhaps not unsurprising. For example, consider the amount of power the wind fleet produces during a typical windy or and calm week (Exhibit 4.12). It is apparent that wind output can be high for many hours or even days on end, with the reverse also being true of periods of calm.

[21] This scenario was chosen as it was the first to be modelled after the Contracted Batteries scenario and was therefore the first opportunity to investigate different storage mixes.

Exhibit 4.12 – Projected 2030 wind fleet output in a typical windy week and a typical calm week (GWh)

When it's windy, it's often windy for many hours or even days in a row



Source: AFRY Management Consulting

When this analysis is expanded to look at an entire year, the findings include:

- around half of the year is at times when wind fleet output is repeatedly high[22] or low[23] (Exhibit 4.13);
- the longest period of repeatedly high wind output is almost nine days, with the longest period of repeatedly low output around 7 days; and
- the average duration of periods of repeatedly high wind output is around 22 hours with average an duration of around 16-17 hours for periods of repeatedly low wind output.

With half of the year comprising periods that see 16-22 hours of repeatedly high or low wind output, this explains why 2 hour storage assets do not provide as much additional net welfare benefit as longer duration storage: they do not store enough energy to allow for high levels of utilisation (Exhibit 4.15); and they do not allow for much offsetting of thermal peaking capacity due to the high de-rating factors applied.

[22] I.e. outputting at a capacity factor of greater than 50% for 2 or more consecutive hours.
[23] I.e. outputting at a capacity factor of less than 10% for 2 or more consecutive hours.

Exhibit 4.13 – Hours when projected 2030 wind fleet output is repeatedly high or low (% of year)

Wind output is repeatedly high or low for around half of the year

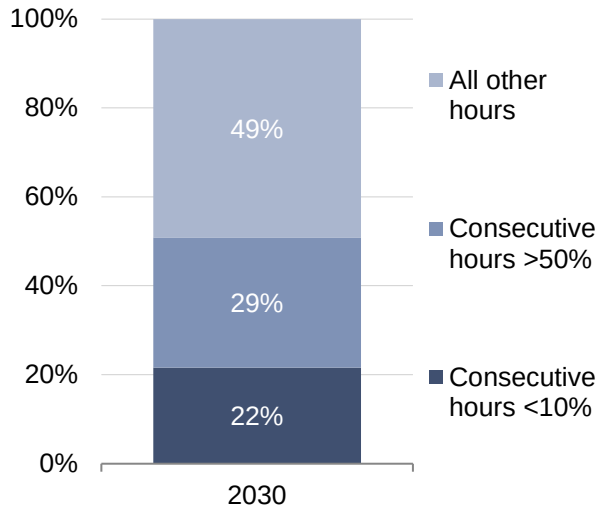


Exhibit 4.14 – Average duration of periods when 2030 projected wind fleet output is high or low (hours)

When wind fleet output is high, it tends to be high for 22 hours in a row on average

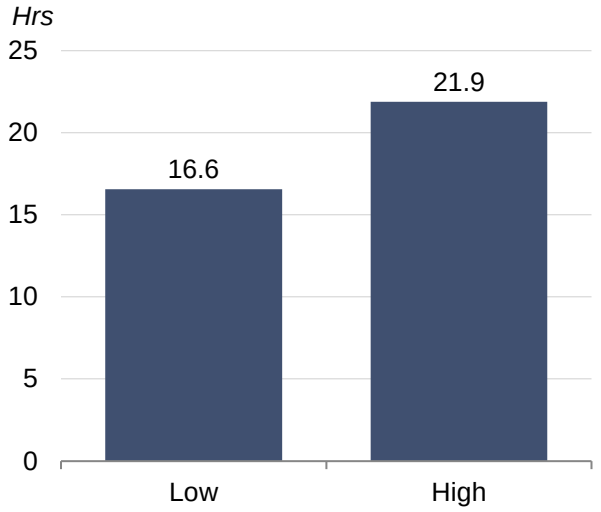
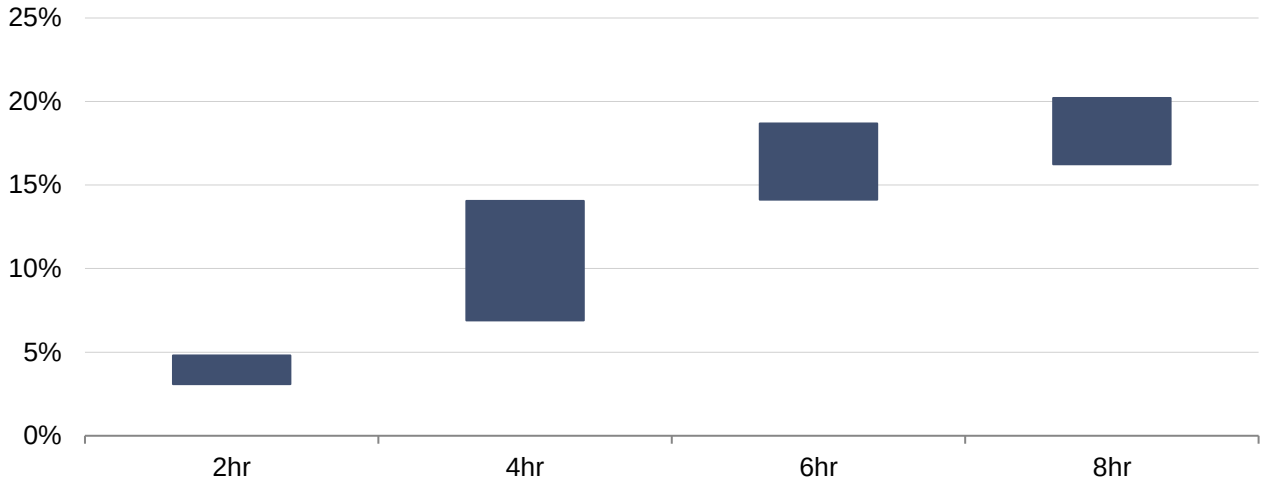


Exhibit 4.15 – Illustrative storage utilisation across all scenarios (MWh injected / MW installed*8760hrs)

2 hour storage utilisation is significantly lower than other storage durations



4.3.2 The role of longer-duration storage

When we perform a similar analysis examining the annual net welfare benefits associated with different mixes of storage duration in the 1.9GW total storage scenario, we again find that 6 hour storage appears most promising.

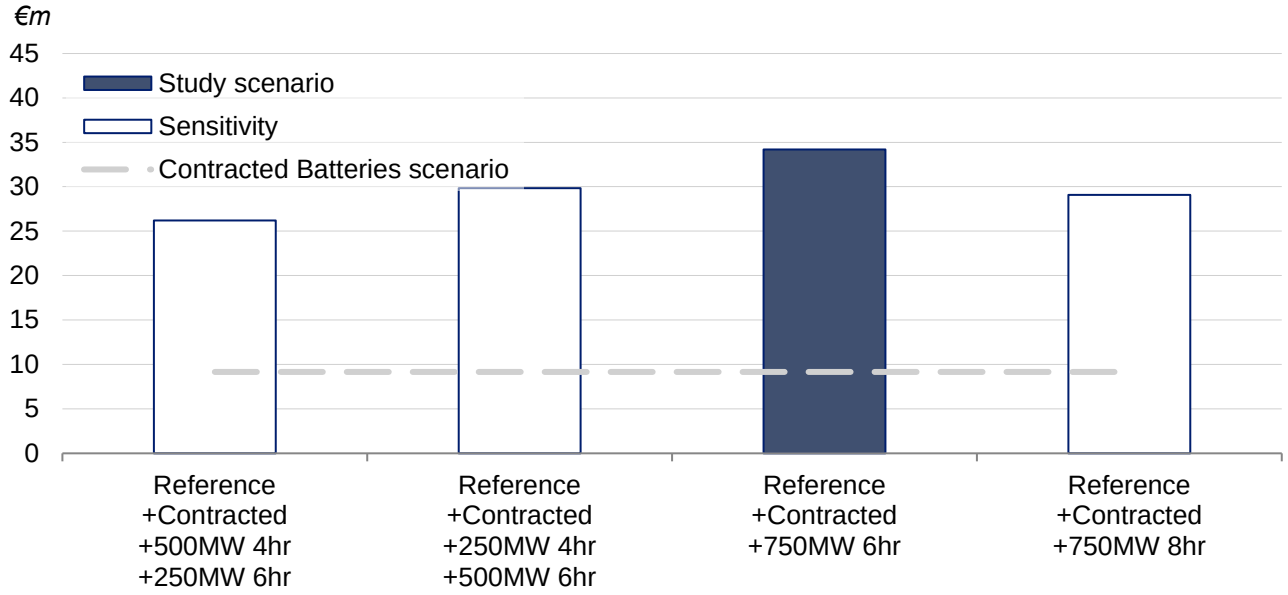
Exhibit 4.16 shows that 4 hour storage delivers smaller increases in value than 6 hour storage (as evidenced by the height of the two leftmost columns

vs. the dashed grey line compared to the dark blue column). 6 hour storage, whilst more expensive, is able to offset more thermal peaking capacity (due to less punitive de-rating factors) whilst having higher utilisation (Exhibit 4.15) and thus greater benefits on dispatch down and the related benefits this brings.

Interestingly, when 8 hour storage is included instead of 6 hour storage (see rightmost column), Net Welfare benefits are slightly reduced. This is largely a function of the higher costs of 8 hour storage and the fact that 8 hour storage is currently unable to replace any more peaking thermal capacity than 6 hour storage because it receives the same de-rating factors as 6 hour storage. 8 hour storage also does not have the same utilisation benefits over 6 hour storage that 6 hour storage has over 4 hour.

Exhibit 4.16 – 2030 annual Net Welfare benefits vs. Reference in the 1.9GW total storage scenario under different mixes of storage duration (€ millions, real 2020 prices)

4 hour and 8 hour storage generates less societal value than 6 hour storage in this study



5 Barriers to storage roll out in Ireland

The fundamental barrier to future development of energy storage in the SEM is the potential lack of a viable business model resulting from the benefits of storage not being appropriately valued. There are multiple reasons why this could be the case, ranging from markets that were designed for conventional and / or renewable generation to regulatory instability, and so on.

Our analysis suggests there are several specific barriers that could impede the development of storage (and particularly longer-duration storage) in the SEM, including:

- uncertainty over the regulatory framework for System Services beyond April 2024, which increases investment risks;
- the lack of a level playing field in existing support mechanisms (specifically RESS and the CRM) for storage, which results in the benefits of storage not being appropriately valued;
- a grid connection policy that implicitly disadvantages energy storage projects;
- a transmission network charging design that does not incentivise flexibility;
- policy emphasis focussing on short-duration storage rather than long-duration storage, which might suggest that not much more is required of energy storage in the SEM; and
- a complex web of critical stakeholders that complicate decision making, which can slow progress on a range of critical actions.

We discuss each of these below.

5.1 Uncertainty over future System Services regime

System Services uncertainty deters investment

DS3 System Services are currently procured under the Volume Uncapped (VU) Regulatory arrangements. Following a one year extension, the VU Regulated Arrangements expire on 30 April 2024. Beyond this, there is not currently a definitive regulatory framework for System Services and the current discussions for the System Services Future Arrangements suggest it could be significantly different from the existing VU Regulated Arrangements.

Specifically, rather than being centred on price regulation, the System Services Future Arrangements are expected to be focussed on volume regulation. In practice, this means that instead of the current regime that has regulator-set tariffs for different System Services, the new regime may implement volume-limited competitive tendering for a wide range of System Services, including the majority of products of relevance to storage (i.e. balancing capacity and ramping margin).

From an investment perspective, the critical issue is that the System Services Future Arrangements may introduce short-term (potentially daily) auctions that could result in significantly more volatility of income from System Services for storage assets. While this may result in reduced costs to consumers in the event there is sufficient supply of System Services, if there are shortages of supply, this approach is unlikely to provide sufficient incentive (even when coupled to other revenue streams) to develop new capacity that can provide the required volume of System Services.

5.2 Lack of a level playing field in existing support mechanisms

In the SEM, both the CRM and RESS can be considered as financial support mechanisms for thermal and renewables capacity that might not otherwise be developed[24] solely on the basis of energy market revenue and System Services income alone. The key issue is that storage, and particularly long-duration storage, is not able to compete on a level playing field with other technologies in the CRM and does not qualify for RESS.

5.2.1 CRM

The treatment of DSUs and storage in the CRM is inconsistent

The CRM, like most capacity markets in Europe, is based around the concept of firm capacity. This differs from installed capacity because it takes account of the probability that a generator will actually be available to provide its capacity at times of greatest system stress. The adjustment applied to a generator's installed capacity is known as its de-rating factor.

For all generators, a part of the reduction in installed capacity will relate to expectations for planned and unplanned maintenance. For thermal generators, the impact of ambient temperatures is also reflected. For technologies that cannot be dispatched, e.g. wind and solar, the de-rating factor will also reflect what the wind speed and solar irradiation conditions are expected to be when demand is at its highest.

The critical barrier we have identified relates to the de-rating factors applied to storage and particularly long-duration storage. Under the current methodology for calculating de-rating factors, even six hour duration storage is not considered comparable to a thermal generator with respect to de-rating factors Exhibit 5.1. Interestingly, demand side units (DSUs) with a maximum down time of **less than six hours** (i.e. units that can have their

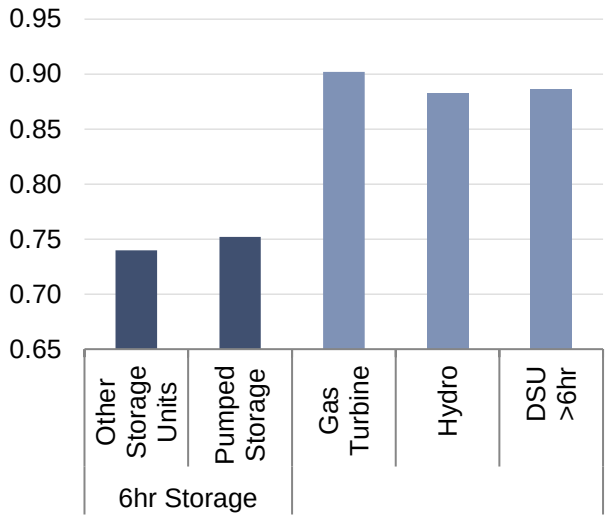
[24] A similar argument could perhaps be made for the existing VU Regulated Arrangements and short-duration storage, but this framework will soon expire.

demand reduced for periods less than six hours) receive the same de-rating factors as Other Storage Units (i.e. all storage that is not pumped storage), whilst DSUs with a maximum down time of **greater than six hours** are treated similarly to thermal generation and hydro. Consequently, DSUs that act like long-duration storage receive preferential treatment in comparison to storage.

By contrast, in the GB Capacity Market, storage with durations longer than 5 hours are treated as broadly equal to thermal generation (Exhibit 5.2). We understand there are methodological differences in the way de-rating factors are calculated between the GB Capacity Market and the CRM, but these methodological choices, along with the tools used in the CRM, do not appear to provide a level playing field for long-duration storage.

Exhibit 5.1 – Comparison of CRM de-rating factors for different technologies

Other Storage Units face more stringent de-rating factors than other technology types, including pumped storage

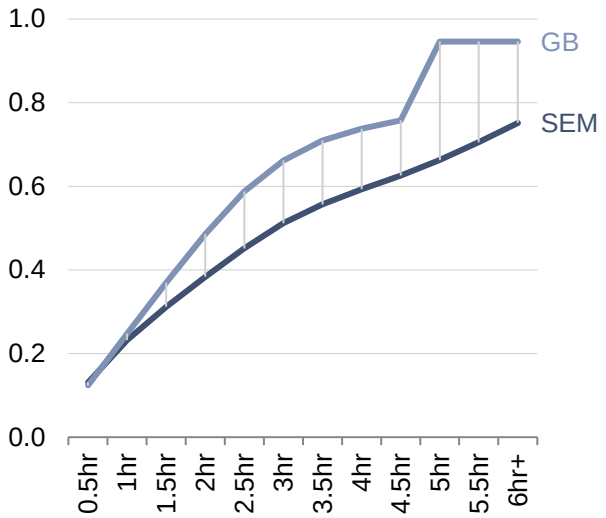


Notes: De-rating factors shown are for a 50MW unit for all technology types.

Source: EirGrid / SONI, Capacity Market – Final Auction Information Pack FAIP2425T-4, 8 December 2020.

Exhibit 5.2 – Comparison of GB storage and SEM Other Storage de-rating curves

GB Capacity Market storage de-rating factors are significantly more generous than those applied in the CRM



Notes: De-rating factors for storage in the SEM is calculated as the average de-rating factor across units ranging in size from 0MW to 60MW.

Source: EirGrid / SONI, Capacity Market – Final Auction Information Pack FAIP2425T-4, 8 December 2020; National Grid ESO, Capacity Market Auction Guidelines 2020 four year ahead Capacity Market Auction (T-4), 9 February 2021.

It is also worth noting that Other Storage Units receive lower de-rating factors than pumped storage of a similar storage duration due to the application of system wide outage statistics rather than technology-specific values. Historically, this was justified on the grounds of a lack of actual outage data for Other Storage Units. However as increasing amounts of energy storage are deployed in the SEM, this position becomes more problematic to maintain.

5.2.2 RESS

Storage reduces the cost of RESS but storage can't compete for this value

The RESS is a Contracts-for-Difference (CfD) scheme that provides a degree of price certainty for eligible renewable generation technologies for a period of around 15 years. The intention of the scheme is to "*promote the generation of electricity from renewable sources*"[25].

The issue we have identified is that storage is not eligible to participate in the scheme, despite the fact that:

- in a system with a very high level of renewables, storage does promote the generation of electricity from renewable sources; and
- by making renewables generation more effective, storage has the potential to reduce the burden of the PSO Levy.

In short, storage is able to provide some of the benefits of renewables, but is prevented from directly competing for the support made available to other providers of these benefits.

Identifying the solution to this will require further consideration, however this study highlights the fact that storage is able to provide many of the benefits of other technologies and yet is not allowed to compete for support in the same way as these technologies.

5.3 Grid connection policy

ECP-2 is implicitly disadvantaged against storage

The framework governing provision of grid connections in Ireland is known as the Enduring Connection Policy Stage 2 (ECP-2)[26]. ECP-2 provides for 3 batch application windows for grid connections in 2020, 2021 and 2022, with a target of 115 connection offers being provided in each batch. Of these 115 offers:

- 15 are reserved for 'non-batch' applications, which are effectively small projects and autoproducers;
- 15 are reserved for community-led renewables projects; and
- 25 are reserved for the largest (by MWh of output) renewables projects.

The remaining 60 offers are prioritised by earliest planning permission grant date and no more than 10 of these can be allocated to "primarily storage or other system service technology projects".

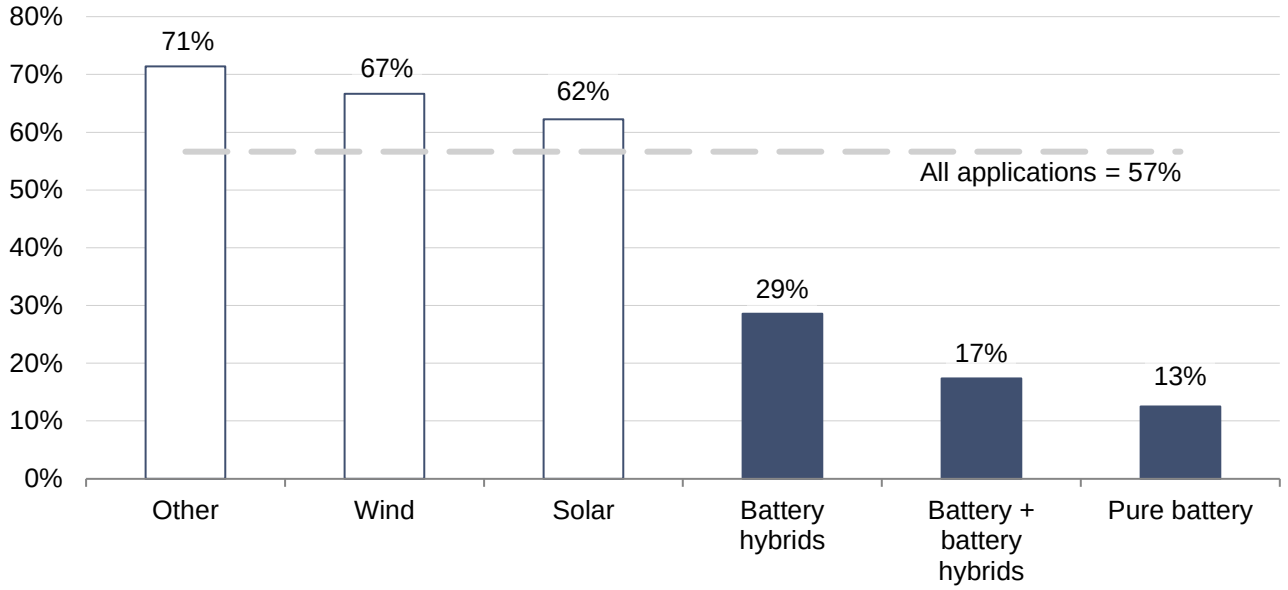
Notwithstanding the cap on offers to storage projects, the prioritisation of offers by planning permission grant date implicitly disadvantages storage projects as these tend to be amongst the newer projects. This in turn stems from most energy storage technologies being less mature than onshore wind or solar. More specifically, the success rate in ECP-2.1 (i.e. the first batch of

[25] Government of Ireland, Terms and Conditions for the First Competition Under the Renewable Electricity Support Scheme RESS 1:2020, February 2020.
[26] CRU, Enduring Connection Policy Stage 2 (ECP-2) Decision (CRU/20/060), 10 June 2020.

ECP-2) for all projects that had some energy storage capacity was only 17% compared to 60-70% success rates for wind and solar (Exhibit 5.3).

Exhibit 5.3 – Success rates in ECP-2.1 by technology

Although energy storage is not explicitly disadvantaged in ECP-2, the rules appear to disadvantage energy storage projects



The design of TUoS charging could be better aligned with achieving 2030 targets

5.4 Transmission network charging design

The current design of Transmission Use of System (TUoS) charging in Ireland provides locational signals that incentivise the development of generation in areas where network congestion is high. It does not, however, take account of temporal variations in congestion. Consequently, a unit that imports at full capacity when wind output is high / demand is low is charged the same amount as if it imported at full capacity when wind output is low / demand is high. This results in a lack of incentive (with respect to TUoS charges) to provide flexibility and potentially results in the charges applied to energy storage not reflecting their true cost to the network.

We note that in Ireland, Distribution Use of System (DUoS) charges already have scope for temporal variation with the possibility of separate day and night tariffs, whilst in Northern Ireland, generator import charges vary by season, day of week and time of day.

Policy emphasis needs to shift to long-duration storage

5.5 Lack of clear policy emphasis on storage

In the Climate Action Plan (CAP)[27], there is a clear understanding that storage has a role to play in the transition to net zero and in achieving 2030

[27] Government of Ireland, Climate Action Plan 2019, 17 Jun 2019.

targets. The CAP even states: "*We will strengthen the policy framework to incentivise electricity storage and interconnection*".

However, it appears that the focus of policy makers is currently on short-duration storage and the role that this can play in ensuring network stability rather than on storage more broadly. For example, in the CAP 4th progress report[28] the Commission for Regulation of Utilities (CRU) "*reports good progress to-date on introduction of storage*" with the status of this particular action[29] was marked as "Complete". While it is abundantly clear that good progress has been made with respect to short-duration storage, the same cannot be said for long-duration storage. Given the current lack of long-duration storage (in part because costs for long-duration storage remain relatively high), the lack of explicit recognition of the value and role of long-duration storage is a clear barrier to future deployment.

5.6 Market structure

Numerous key stakeholders complicates and slows decision making

There are multiple critical stakeholders in the All-Island electricity sector including, *inter alia*:

- the TSOs, EirGrid and SONI;
- the TAOs, namely ESB Networks and NIE Networks;
- the regulatory authorities (RAs), with CRU in Ireland, the Northern Ireland Authority For Utility Regulation (NIAUR), and SEM Committee (SEMC); and
- the Ireland and Northern Ireland governments.

The existence of a single market operating in two countries alongside the consequent doubling of the number of critical stakeholders creates significant coordination and execution challenges with respect to all aspects of market design, and particularly support mechanisms for capital assets in the power sector. Consider for example, the delays to the introduction of new / updated markets (e.g. ISEM, RESS, the lack of a support scheme for renewables following the expiry of the Northern Ireland Renewable Obligation (NIRO)) – although it is hard to be definitive, it seems reasonable that these delays have been in part related to the complexities of the All-Island electricity market.

Although there is a clear recognition of this issue by those involved, the complexity of the 'power market'[30] nonetheless raises the possibility that decision making could be delayed due to complex administration and a wide range of competing interests and incentives.

[28] Government of Ireland, Climate Action Plan 2019 Fourth Progress Report Q2 2020.
[29] See Action 24, and specifically the step "*Review of policy regulatory framework for electricity storage…*"
[30] Used in its broadest sense to cover all of the various markets, market participants, regulators, governments, etc.

6 Storage best practice

Best practice to supporting or incentivising appropriate deployment of storage is superficially simple: create a level-playing field for energy storage such that its costs and benefits are fairly reflected and investors (either private sector or government) can make appropriate capital allocation decisions. In order to achieve a level-playing field, there are several areas that should be considered, relating to:

- explicit defining of energy storage in primary legislation;
- network charging;
- taxation;
- market access; and
- support.

6.1 Definition of storage

It is critical that storage is explicitly defined in power-related primary legislation. Historically, the power sector has identified generators and suppliers as two of its key actors which has resulted in issues for energy storage, particularly with respect to network charging and taxation (see below for additional details).

Given the role that energy storage will likely play, the definition of storage should be addressed in primary legislation. In the case of Ireland, this would provide a strong signal that reinforces the need to develop enduring solutions to several issues that have so far only had interim fixes implemented (e.g. network charging). Critically, any definition of energy storage should reflect the fact that energy can be valuably stored in multiple forms (e.g. electrical, thermal or kinetic energy) by a diverse range of technologies. It should not be equated with solely the absorption and injection of active power.

6.2 Network charging

Network charges are typically determined on the basis of how much volume a user consumes / injects or how much capacity to consume / inject a user has. Because storage units both export and import power, they have often been charged twice for use of the network in part because storage has not been explicitly defined in legislation and subsequent regulation. This was the case in Ireland until as recently as 1 October 2020 at which point EirGrid

ceased charging commercial storage units on their Generator Transmission Use of System (GTUoS)[31].

Considering the potential for energy storage to reduce network congestion and perhaps lower the amount of network investment required, best practice should ensure that the network charges paid by storage reflect the cost of storage to the network. In this regard, the current practice of charging storage based on a **flat tariff** on demand does not constitute best practice given the benefits storage can provide at times of high (and potentially excess) wind output.

6.3 Taxation

Another area that is also frequently linked to the definition of a market participant (as generation or supply) is taxation. In some countries, energy that is used to charge storage assets is taxed twice, once when imported by the storage unit and a second time when consumed by the end user. In Ireland, this has not been the case (with respect to the PSO Levy) since 2004 when CRU determined that the Turlough Hill pumped storage units were not to be considered as a final customer for energy imported whilst pumping[32].

Best practice with respect to taxation of energy storage focusses on avoiding the double taxation of electricity consumption. In some cases this has been implemented by exempting storage from taxation. In the Irish case, full exemption has not been implemented with a distinction instead being made between importing power for the purposes of charging and consumption of power for house load[33].

6.4 Market access

In general, the key principle concerning market access is that storage should be allowed to compete on a level-playing field in all of the key power markets, including:

- wholesale markets;
- balancing markets;
- ancillary services; and
- capacity markets.

It is important that markets are aligned with the technical characteristics of storage. In the wholesale and balancing markets, this may be related to the types of orders that can be placed (e.g. linked orders). In capacity markets, this could reflect issues such as recognising the differing contribution to security of supply of storage of different durations.

[31] CRU, Network Charges for Commercial Storage Units Interim Solution (CRU/20/115), 29 September 2020.
[32] CRU, CER/04/193.
[33] CRU, Information Paper Application of the PSO Levy to Commercial Storage (CRU/19/034), 29 March 2019.

In broad terms, storage in Ireland and Northern Ireland is able to access all of the key markets, albeit not always on a level playing field. There are notable exceptions, specifically with respect to DS3 System Services, where not all forms of storage technology are included on the Proven Technologies List and are thus not eligible to provide System Services (e.g. LAES).

However, one area where this is not the case is with respect to hybrid assets comprising storage and another technology. In general, hybrid assets are not well recognised and developers / owners can face obstacles to accessing markets appropriately. For example, in RESS, because the design of the scheme prioritises a participant's strike price bid (as opposed to the strike price compared to the expected capture price and thus the cost to the PSO Levy), a hybrid asset can only take advantage of potential capital cost savings (related to shared grid connection costs) or reduced exposure to negative prices / curtailment. Benefits that result from changes to a project's generation profile (and therefore capture price and cost to the consumer) will not be captured without the introduction of hybrid specific Evaluation Correction Factors (ECFs).

The ECF is a parameter in the RESS auction that is used to adjust bids by different technologies for the purposes of establishing the auction merit order[34]. In RESS 1 this was set to a value of one, but it is expected that non-unitary values will be used in RESS 2. However, in the Draft Terms and Conditions for RESS 2[35], there is no indication that hybrid projects will receive a different ECF to that of the underlying renewable technology.

6.5 Support

Direct support for storage is not generally viewed as a particular barrier to deployment, with emphasis typically placed on avoiding or reducing market and regulatory barriers instead[36]. With that said, it is important that where support mechanisms exist, they should not be designed in such a way that disadvantages storage with respect to other technologies.

For example, renewables support mechanisms should ensure that support is not paid when market prices fall below zero as this disincentivises generators from behaving in a balance responsible manner (removing an incentive for the renewables developer to consider storage as part of their project) whilst distorting market prices. Similarly, given the potential benefits of hybrid assets that include energy storage, there is an argument for ensuring that these types of assets be explicitly recognised as potential participants.

[34] This might be desirable, for example, in the case that capture prices differ significantly between renewables technologies (as they do for onshore wind and solar). In this case, an onshore wind project and a solar project could bid the same strike price but have very different costs to the PSO Levy.
[35] DECC, Draft Terms and Conditions for the Second Competition under the Renewable Electricity Support Scheme, June 2021.
[36] European Commission, Study on energy storage – Contribution to the security of the electricity supply in Europe, March 2020.

In the case of RESS and the CRM, the picture for storage is somewhat mixed. On the one hand, storage is explicitly prevented from participating in RESS, but RESS does not compensate renewable generators when prices are negative. Similarly in the capacity market, although the market has been designed with the complexities of storage in mind, the specific implementation has inconsistencies that disadvantage long-duration storage particularly with respect to other technologies (specifically DSUs with a maximum downtime greater than 6 hours).

7 Recommendations

This chapter contains a number of key recommendations that result from the consideration of the analysis presented in this report, and the assessment of range of issues facing energy storage deployment in the Irish market.

7.1 Develop a comprehensive energy storage policy

It is uncontroversial that energy storage will play a critical role in addressing the technical challeneges facing the All-island power system in the coming years. Furthermore, our analysis suggests that energy storage will help Ireland achieve its 2030 targets as well as accelerate the transition to net zero by reducing power sector emissions, all whilst saving money for consumers.

Consequently, we recommend a comprehensive energy storage policy is developed by EirGrid / SONI, CRU and DECC as part of Ireland's National Climate Policy. This policy should explicitly recognise the key role of energy storage in maximising Ireland's renewable generation potential and seek to remove barriers preventing the deployment of an appropriate amount of energy storage.

7.2 Address inconsistencies in the design of the CRM

Our analysis suggests that long-duration storage is disadvantaged in the CRM in relation to de-rating factors. DSUs with a maximum down time of less than 6 hours are grouped with energy storage that is not pumped storage. However, DSUs that have a maximum down time greater than 6 hours are treated independently and are considered to provide a similar contribution to security of supply as thermal plant. This is not the case for energy storage with durations greater than six hours. Because of this, long-duration storage is not currently able to compete on a level-playing field in the CRM, and consumers are not able to avail of the benefits that long-duration storage can provide.

We recommend that the Single Electricity Market Operator (SEMO) considers applying the de-rating factors for "DSU > 6hrs" to energy storage units with a storage duration of greater than six hours as soon as is practically possible.

7.3 Remove implicit disadvantage against storage from the Enduring Connection Policy

The design of ECP-2 implicitly disadvantages storage by emphasising planning permission grant date as the criterion for being processed for a connection offer for all but the largest (renewables) and smallest projects.

We recommend that CRU:

- assesses the role that storage and particularly longer-duration energy storage can play in Ireland's energy transition;
- evaluates whether the design of ECP-2.3 reflects the contribution that longer-duration storage can provide; and
- considers including a minimum number of offers for energy storage.

This should take place ahead of the September 2022 deadline for ECP-2.3 applications.

By adjusting the design of ECP-2.3 so that it guarantees connection offers to a small number of energy storage projects CRU will improve the likelihood that 2030 targets are met at lower costs to consumers.

7.4 Clarify the rules governing hybrids in RESS

Although the Terms and Conditions for RESS-2 go some way towards addressing the role of hybrids, the proposals do not go far enough. Specifically, they do not allow for renewables projects choosing to include storage behind the meter to have a different ECF to the same project without storage. Thus, although the project with behind the meter storage will have a different generation profile and will potentially have a lower cost to the PSO Levy, this benefit is not reflected in the auction merit order.

The RESS 2 Terms and Conditions also do not recognise the potential role of 'contractual' hybrids that are not co-located with the renewables project. In practice, this limits a developer to choosing to locate storage behind the meter (which effectively limits the capability of the storage to provide System Services) or to meter the storage and renewables capacity separately (which removes the ability of the storage to reduce exposure to negative price risk and curtailment).

An alternative could be to allow for an independent storage project to contract with a RESS project such that the RESS project effectively has behind-the-meter storage, whilst allowing the storage project to participate in the Day Ahead Market, Balancing Market, Capacity Market and System Services with the remainder of its uncontracted capacity. Although this would not allow for any synergies with respect to connection costs, it could provide a source of low cost charging for the battery, whilst allowing the RESS project to mitigate some negative pricing / curtailment risk and better match its 'output' to changes in supply-demand balance.

Consequently, we recommend that the Department of the Environment, Climate and Communications (DECC):

- retains the ability to implement different ECFs for hybrid projects to the ECF of the underlying renewables technology if appropriate; and
- explores alternative definitions of a hybrid, including contractual hybrids.

7.5 Increase incentives for flexibility

Currently, most incentives for flexibility are provided by differentials in market prices. There are, however, unused sources of incentive, including:

- transmission network charging which does not provide for any temporal variation in charges; and
- the PSO Levy which is based on electricity consumption.

In order to increase the flexibility of the power system, we recommend a comprehensive review of all flexibility incentives. This will likely require input from EirGrid / SONI, ESB Networks / NIE Networks and the RAs. As a minimum this review should cover:

- transmission network charging, including the potential for introducing temporal variation to charges (e.g. linked to the SNSP);
- the basis for recovering the PSO Levy and whether flexible consumption (e.g. that delivered by thermal storage that creates new flexible electrical load by offsetting fossil fuel load but does not inject power back into the network) should be treated more favourably than inflexible consumption; and
- new System Services products targeting congestion management that can incentivise the use of storage to reduce the load on the network at times of high SNSP as well as local congestion.

Annex A BID3 power market model

BID3 provides a simulation of all the major power market metrics on an hourly basis – day ahead (and for the SEM , balancing market) electricity prices, dispatch of power plants and flows across interconnectors (Exhibit A.1). It is an economic dispatch model based around optimisation.

It simulates the hourly generation of all power stations on the system, taking into account fuel prices and operational constraints such as the cost of starting a plant. It accurately models renewable sources of generation such as hydro, reflecting the option value of water, and intermittent sources of generation, such as wind and solar using detailed and consistent historical wind speed and solar radiation. It fully models all sources of flexibility on the system such as pumped storage, batteries and Demand-Side Management, and also new technologies such as electrolysis and hydrogen CCGTs.

The result of this optimisation is an hourly day ahead dispatch schedule for all power plants and interconnectors on the system. The results of this modelling allow us to provide projections for wholesale power markets and the CRM. It also provides the dispatch schedule from which the system is redispatched at the BM stage and can thus be considered as the first step for providing projections for BM revenues and System Services revenues.

For the Irish market, we extend the modelling into the balancing timeframe. This involves redispatching from the day ahead schedule to account for renewables / demand imbalances as well as major system constraints (Exhibit A.2). The resulting outputs allow us to assess a range of factors, including: outturn dispatch of thermal plant; plant-specific revenues from the BM; system curtailment (particularly relevant for intermittent renewables in the SEM); and the DS3 temporal scarcity scalar.

Exhibit A.1 – Overview of BID3

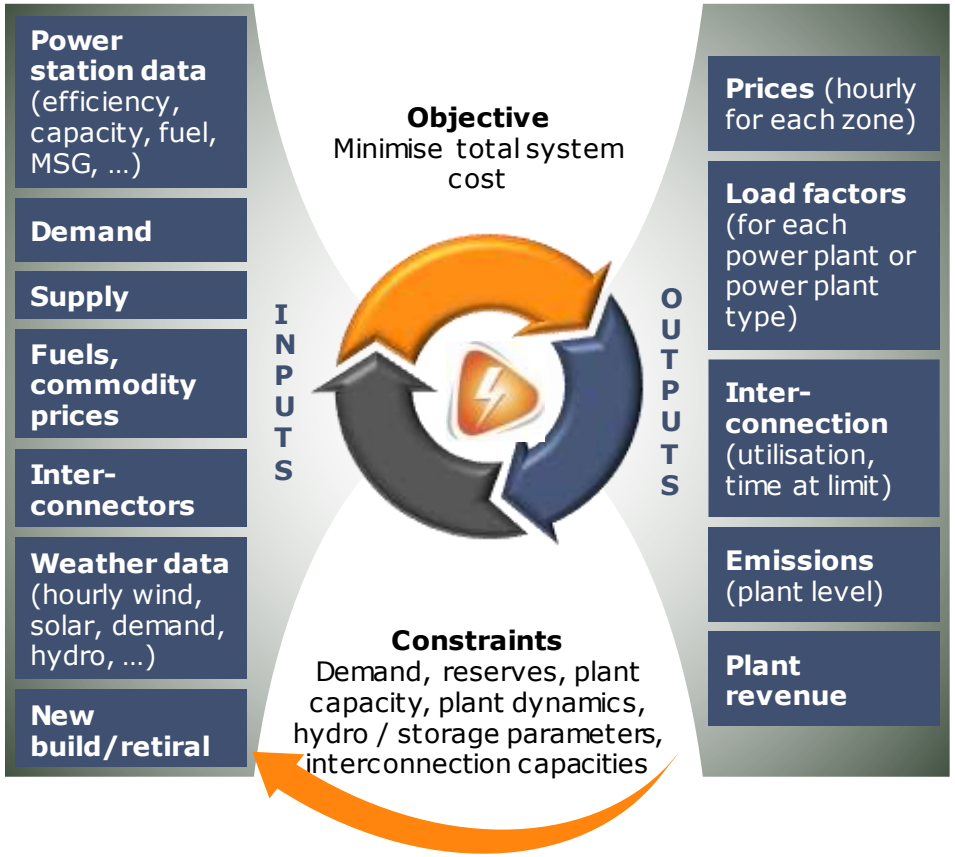
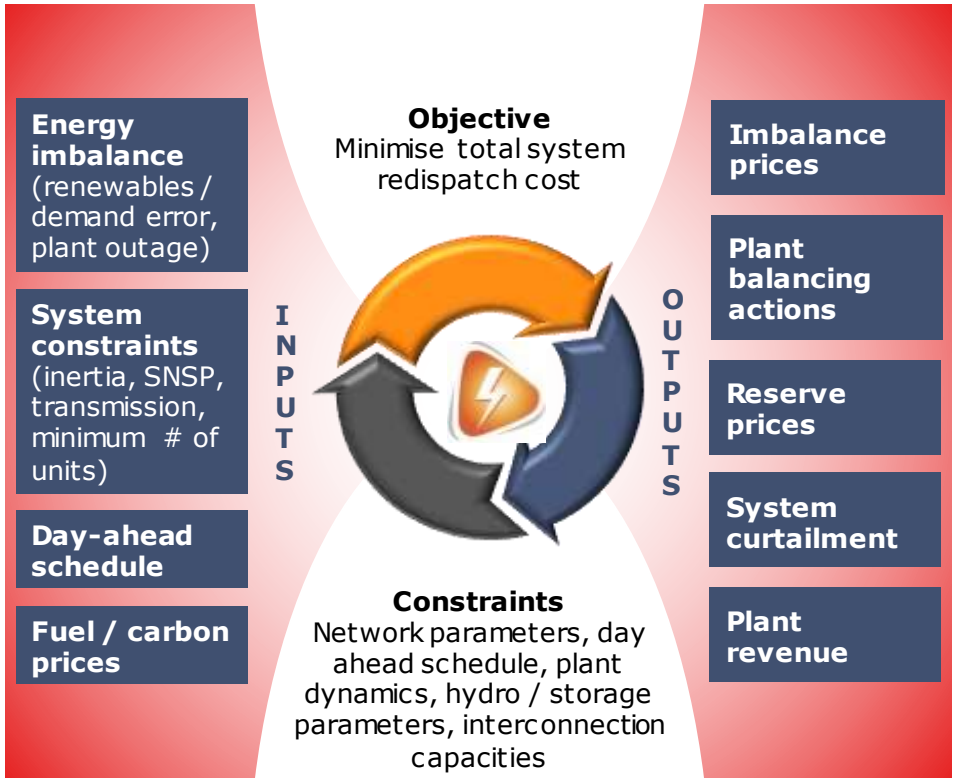


Exhibit A.2 – Balancing market modelling in BID3



Annex B Key model inputs

B.1 Fuel and carbon prices

Fuel and carbon prices for 2030 have been taken from National Grid ESO's Base Case in the 2020 Future Energy Scenarios study[37], as shown in Exhibit B.1.

Exhibit B.1 – 2030 fuel and carbon prices: Natural gas (NBP) – p/therm; Carbon (EU ETS) – €/tCO_2; Steam coal (ARA CIF) - $/tonne; and Crude oil (Brent) - $/bbl (all real 2020 prices)

Input	Description	Units	Value
Natural gas	NBP	p/therm	58.0
Carbon	EU ETS	€/tCO_2	56.7
Steam coal	ARA CIF	$/tonne	82.3
Crude oil	Brent	$/bbl	76.5

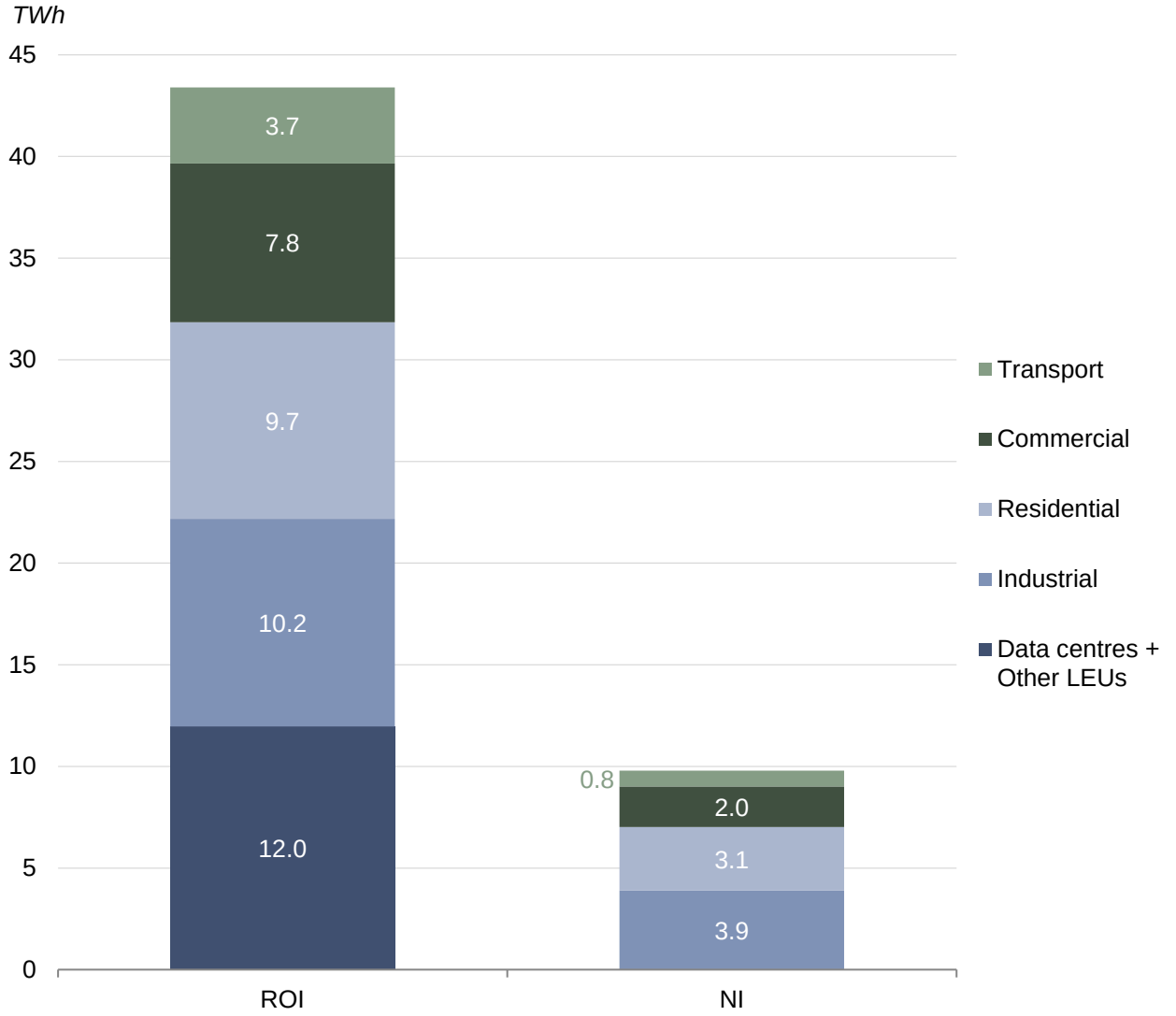
Notes: Original data was published in 2018 prices and have been converted to 2020 prices by AFRY. A GBP 1 = EUR 1.13 exchange has been used to convert the carbon price.
Source: National Grid ESO

[37] National Grid ESO, Future Energy Scenarios 2020 Data workbook, 28 September 2020.

B.2 Annual power demand

Annual power demand in 2030 for the SEM is taken from EirGrid's Shaping Our Electricity Future Technical Report[38], as shown in Exhibit B.2. We have assumed the mid-point of EirGrid's range for annual demand in each sector in Ireland.

Exhibit B.2 – 2030 annual SEM power demand by category (TWh)



Source: EirGrid / SONI

[38] EirGrid / SONI, Shaping Our Electricity Future Technical Report, 8 March 2021.

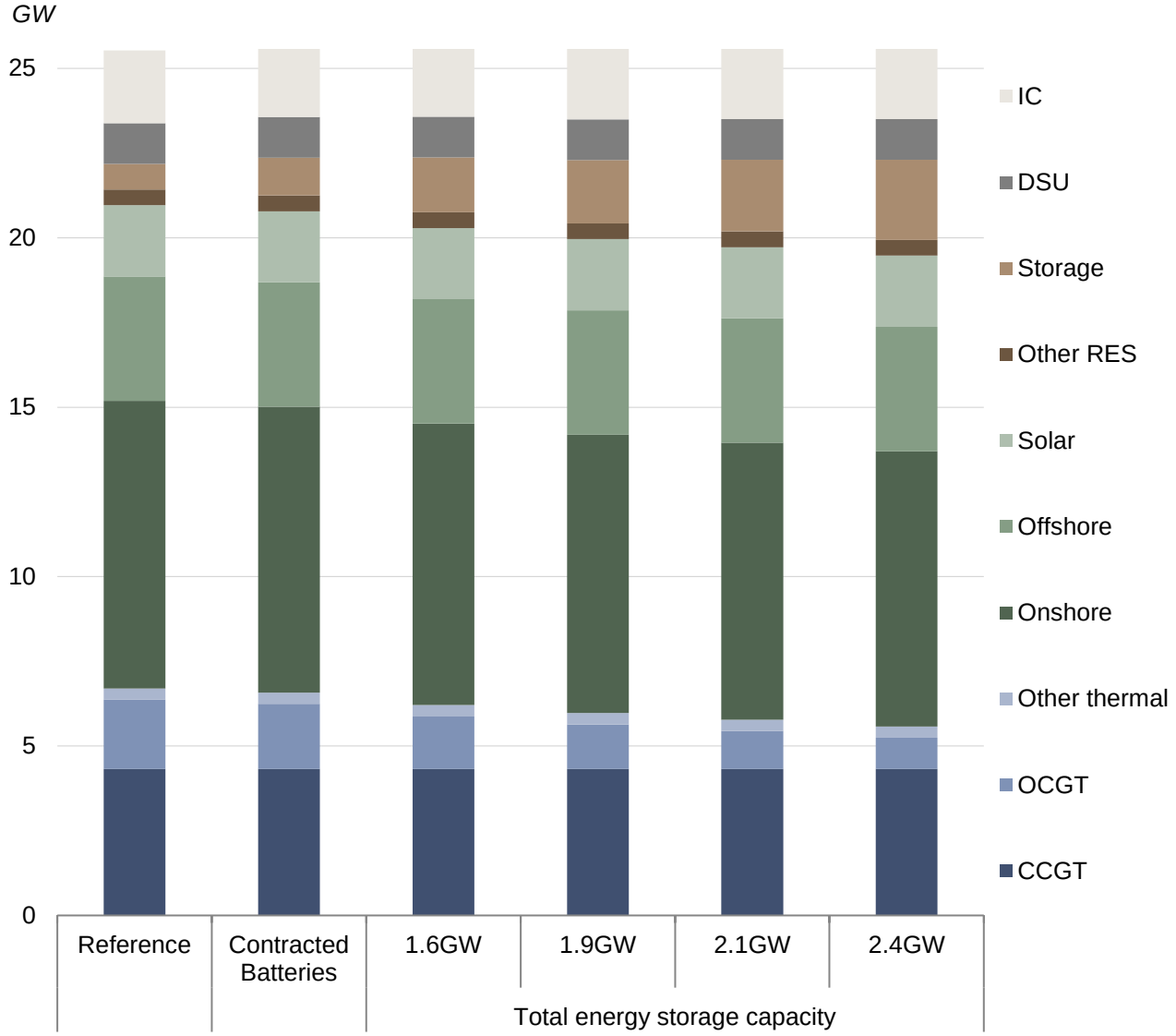
B.3 Generation capacity mix

The 2030 generation capacity mix has been determined such that:

- there is sufficient capacity margin to ensure supply meets demand; and
- outturn renewables penetration is 70% in 2030.

A summary of the installed capacity mix by technology type for each of the scenarios modelled in this study is shown in Exhibit B.4 and Exhibit B.4.

Exhibit B.3 – 2030 generation capacity mix by scenario (GW)



Source: AFRY Management Consulting

Exhibit B.4 – 2030 generation capacity mix data table (GW)

Technology	Reference	Alternative Scenarios				
		Contracted batteries	1.6GW storage	1.9GW storage	2.1GW storage	2.4GW storage
CCGT	4.32	4.32	4.32	4.32	4.32	4.32
OCGT	2.05	1.92	1.55	1.32	1.12	0.92
Other thermal	0.33	0.33	0.33	0.33	0.33	0.33
Onshore wind	8.49	8.44	8.31	8.22	8.18	8.13
Offshore wind	3.67	3.67	3.67	3.67	3.67	3.67
Solar PV	2.10	2.10	2.10	2.10	2.10	2.10
Other RES	0.47	0.47	0.47	0.47	0.47	0.47
Pumped storage	0.29	0.29	0.29	0.29	0.29	0.29
0.5hr storage	0.46	0.46	0.46	0.46	0.46	0.46
1hr storage	0.00	0.08	0.08	0.08	0.08	0.08
2hr storage	0.00	0.20	0.20	0.20	0.20	0.20
4hr storage	0.00	0.08	0.33	0.08	0.08	0.08
6hr storage	0.00	0.00	0.25	0.75	1.00	1.25
DSU	1.20	1.20	1.20	1.20	1.20	1.20
Interconnection	2.15	2.15	2.15	2.15	2.15	2.15

Source: AFRY Management Consulting

B.4 CAPEX and fixed OPEX

The CAPEX projections that underpin the analyses above for OCGTs, onshore wind and storage of relevant durations are shown in Exhibit B.5. Equivalent data summarising our fixed OPEX assumptions are shown in Exhibit B.6.

Note that all avoided cost calculations for onshore wind and OCGTs assume **2030** CAPEX / OPEX values. For storage, we have calculated the costs of the additional storage in the **Contracted Batteries** scenario at **2025** CAPEX / OPEX (this includes some 1hr, 2hr and 4hr capacity). The rationale for using 2025 is that these batteries are likely to be developed around this time and assuming 2030 costs would overstate the benefits of this capacity. The cost of the incremental storage capacity in the remaining scenarios is calculated using **2030** CAPEX / OPEX.

Exhibit B.5 – CAPEX by technology (€/kW, real 2020 prices)

Technology	2025	2030
OCGT	N/A	550
Onshore wind	N/A	1090
1hr storage (Li-ion)	493	N/A
2hr storage (Li-ion)	548	495
4hr storage (Li-ion)	758	675
6hr storage (Li-ion)	N/A	840
8hr storage (Li-ion)	N/A	1005

Source: AFRY Management Consulting

Exhibit B.6 – OPEX by technology (€/kW/yr, real 2020 prices)

Technology	2025	2030
OCGT	N/A	28
Onshore wind	N/A	50
1hr storage (Li-ion)	22	N/A
2hr storage (Li-ion)	28	27
4hr storage (Li-ion)	31	30
6hr storage (Li-ion)	N/A	32
8hr storage (Li-ion)	N/A	35

Note: Fixed OPEX includes TUoS charges, rates, fixed operations and maintenance costs, land lease, insurance, asset management, etc. For storage, OPEX includes ongoing cell replacement costs.
Source: AFRY Management Consulting

B.5 System operational constraints

The operational constraints that have been modelled are based on EirGrid / SONI's expectations for 2030 in the 2019/2020 Tomorrow's Energy Scenarios and are summarised in Exhibit B.7.

Exhibit B.7 – 2030 operational constraints

Constraint	Requirement
Primary / secondary reserve	525MW
Tertiary reserve	700MW
SNSP upper limit	95%
Minimum units Ireland	At least 2 high-inertia units always on-load
Minimum units Northern Ireland	At least 2 high-inertia units always on-load
Inertia lower limit	None
North-South interconnector capacity	1100MW N-S, 1100MW S-N

Source: EirGrid / SONI, AFRY Management Consulting

B.6 Cross-border flows

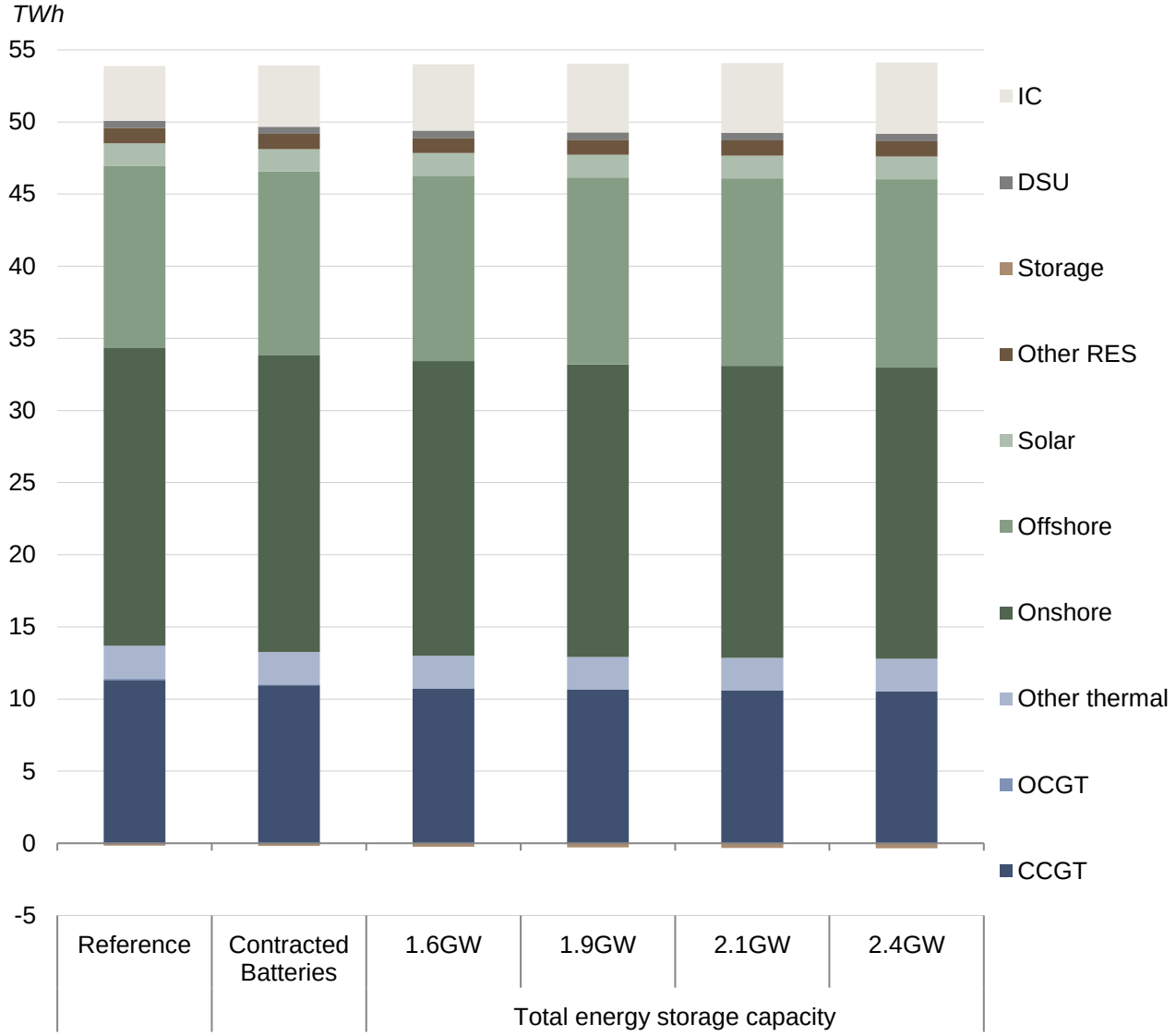
This study assumes 2.15GW of cross-border interconnection capacity (i.e. Moyle, EWIC, Greenlink and Celtic) is operational in 2030. In carrying out this study, we have simulated hourly power prices in 2030 across Europe based on AFRY's 2021 Q1 European Market Quarterly Analysis. The resulting power prices in the SEM, GB and France are used to calculated the flows on the SEM's cross-border interconnectors.

Annex C Detailed model outputs

C.1 Generation mix

A summary of the generation mix by technology type for each of the scenarios modelled in this study is shown in Exhibit B.4 and Exhibit B.4.

Exhibit C.1 – 2030 generation mix by scenario (TWh)



Source: AFRY Management Consulting

Exhibit C.2 – 2030 generation mix data table (TWh)

Technology	Reference	Alternative Scenarios				
		Contracted batteries	1.6GW storage	1.9GW storage	2.1GW storage	2.4GW storage
CCGT	11.33	10.96	10.72	10.64	10.58	10.51
OCGT	0.11	0.06	0.03	0.01	0.01	0.00
Other thermal	2.25	2.25	2.26	2.27	2.27	2.28
Onshore wind	20.63	20.58	20.41	20.29	20.24	20.17
Offshore wind	12.65	12.71	12.86	12.95	13.00	13.06
Solar PV	1.56	1.56	1.57	1.57	1.57	1.57
Other RES	1.05	1.05	1.05	1.05	1.06	1.06
Pumped storage	-0.13	-0.11	-0.08	-0.07	-0.07	-0.06
Other storage	-0.02	-0.06	-0.17	-0.22	-0.25	-0.29
DSU	0.50	0.50	0.50	0.51	0.51	0.51
Interconnection	3.80	4.24	4.61	4.76	4.84	4.94

Note: Interconnection values represent annual net flows, with imports indicated by a positive value and export indicated by a negative value.
Source: AFRY Management Consulting

C.2 2030 annual Net Welfare benefit breakdown

A breakdown of the annual 2030 Net Welfare benefits by scenario and component is shown in Exhibit C.3.

Exhibit C.3 –2030 annual Net Welfare benefit breakdown (€ millions, real 2020 prices)

Driver	Alternative Scenario				
	Contracted batteries	1.6GW storage	1.9GW storage	2.1GW storage	2.4GW storage
(1) Production cost	13.7	34.3	45.3	53.1	59.8
(2) Energy balancing / redispatch cost	10.7	19.6	23.2	25.4	27.7
(3) Avoided onshore wind cost	6.9	25.0	37.1	42.8	50.0
Of which CAPEX	*4.4*	*15.9*	*23.6*	*27.2*	*31.8*
Of which OPEX	*2.5*	*9.1*	*13.5*	*15.6*	*18.2*
(4) Avoided OCGT cost	11.4	38.6	56.8	72.0	87.1
Of which CAPEX	*7.3*	*24.6*	*36.2*	*45.9*	*55.5*
Of which OPEX	*4.2*	*14.0*	*20.6*	*26.1*	*31.6*
(5) Additional storage cost	-33.6	-91.3	-128.1	-159.7	-191.2
Of which CAPEX	-23.6	-65.9	-93.9	-117.3	-140.8
Of which OPEX	-9.9	-25.4	-34.2	-42.3	-50.4
Total (1+2+3+4+5)	9.2	26.1	34.2	33.6	33.3

Source: AFRY Management Consulting

C.3 2030 annual Net Welfare benefit sensitivity analysis

The results of the CAPEX sensitivity analysis described in Section 4.1 is shown in Exhibit C.4.

Exhibit C.4 – Sensitivity of 2030 annual Net Welfare benefit (vs. Reference scenario) to CAPEX assumptions (€ millions, real 2020 prices)

Sensitivity	Alternative Scenario				
	Contracted batteries	1.6GW storage	1.9GW storage	2.1GW storage	2.4GW storage
(1) As modelled	9.2	26.1	34.2	33.6	33.3
(2) Low OCGT CAPEX	8.5	23.9	30.9	29.5	28.3
(3) Low wind CAPEX	8.5	23.6	30.5	29.4	28.4
(4) High storage CAPEX	7.8	18.1	22.0	17.8	13.9
(5) Low OCGT CAPEX + Low Wind CAPEX + High storage CAPEX	6.5	13.4	15.0	9.4	3.9

Source: AFRY Management Consulting

TABLE OF EXHIBITS

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Authors	Alex Blanckley	18 June 2021
Approver	Andy Kelly	22 June 2021

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ÅF and Pöyry have come together as AFRY. We don't care much about making history.

We care about making future.

AFRY Management Consulting Limited
King Charles House
Park End Street
OX1 1JD
Oxford
United Kingdom

Tel: +44 1865 722 660
afry.com
E-mail: consulting.energy.uk@afry.com