Strategies to increase grid flexibility for an isolated system with over 80% renewable electricity in 2030

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***Abstract*—As renewable electricity targets rise around the world, relatively isolated systems reliant on variable renewables, such as wind and solar power, are rapidly facing unresolved issues regarding system security, flexibility costs and remuneration structures for market participants. Although system service payments exist in some electricity markets, there is often insufficient incentive to invest in greater flexibility, either in the demand or supply side. Here, the economic benefits of various flexibility options are considered, leading towards a discussion of market incentives and strategies for reform. In addition to a range of traditional sources of flexibility from conventional generation, interconnection, and short duration batteries, the importance of system stability is emphasised, including synchronous condensers to supplement inertia, as well as medium-duration storage, and a more active balancing role for heat, transport and industrial loads. Each strategy alleviates the use of fossil fuel based gas plants during periods of system stress and enables the absorption of excess renewables. With over 80% of annual energy to be provided mostly by wind and solar power by 2030, Ireland provides a pertinent case for analysis.**

***Index Terms* — high variable renewables, flexibility, heat pumps, electric vehicles, Ireland**

I. Introduction

Island nations are generally well suited to generating electricity from wind power due to favourable weather conditions. However, as power systems that are not well connected to neighbouring grids for contingency support begin to rely predominantly on wind and/or solar power, otherwise known as variable, non-synchronous generation, balancing supply and demand, and ensuring a secure energy supply, becomes more challenging. Flexibility may be defined as how well a power system can adjust to anticipated or sudden fluctuations in demand or supply [1]. It is categorised as either the need to maintain a stable frequency and a secure energy supply at the overall system level, and/or the need to manage bus voltages and transfer capability at a local level. Ireland provides an interesting case to study the operational impact of additional flexibility as an island system, and also as one of the top five countries with the highest share of electricity production from wind in the world, reaching a record 36% of demand in 2020 [2]. To add to this, Irish energy policy aims to more than quadruple installed wind and solar capacity from 4.4 GW in 2021 to 22+ GW in 2030, to reach 80% share of annual demand from renewable energy [3].

Managing the stability of a power system following a disturbance, be it bus voltages or grid frequency deviations, are key operational concerns in isolated power systems with high shares of variable renewables. Large rate of change of frequency (RoCoF) deviations are seen following interruptions of service, generator trip events, and, in the worst case, blackouts. Traditionally, power systems have relied upon the rotational energy, or 'rotational inertia', provided by synchronous thermal power plants to slow down the RoCoF, allowing spare capacity, kept on reserve, sufficient time to respond to frequency disturbances. The RoCoF magnitude is greater with lower total inertia in the system, proportional to a potential power imbalance. For isolated systems, the loss of a single infeed or outfeed, such as a generator or interconnector, can be relatively large. In Ireland, with the introduction of a new interconnector to France, this could reach up to 700 MW in 2030 (compared to a minimum load of ~3 GW). As a result, a flexible and expanded range of technologies will be required to respond to more variable grid conditions, as conventional generation is largely replaced by wind and solar power.

Resources for flexible reserves must be able to provide responses for various durations and activation times, ranging from within seconds (inertial support, fast frequency and primary operating reserve) to tens of seconds (secondary and tertiary operating reserve), or hours (ramping reserve). As the installed wind and solar capacity in Ireland increases beyond 20 GW in the coming years, ramping capabilities must be able to respond to incoming wind fronts and stormy conditions, as well as diurnal solar cycles and seasonal weather variations. At present, a stable frequency is achieved by utilising spinning reserves, interconnectors, hydro resources, or curtailing renewable power. In the future, during times of high wind or solar conditions, renewables may need to provide fast acting reserve, combined with non-synchronous flexibility sources, such as batteries, interconnectors, and demand response, and inertial response from synchronous condensers [4].

The importance of flexible resources when balancing large shares of variable renewables has long been recognised [5]-[8]. Considering the benefits of storage within ERCOT, for an 80% wind and solar share, curtailment was reduced to 10% with an optimal 70/30 wind/solar mix and 12-hour storage capacities. To reach 80% renewables, all must-run generation and spinning conventional reserves were removed [5]. The ensuing technical challenges with maintaining stable voltages and frequency were not directly discussed.

Funded by the Irish Department of Environment, Climate and Communication (DECC)

While unit commitment models have been widely used for assessing future balancing issues in systems dominated by variable renewables, technical considerations such as the security of the system and ensuring critical inertia levels are often overlooked [8]. This can potentially lead to models making unrealistic choices. Similarly, investment models, which solve annually over a number of decades to inform future portfolios, tend to ignore the flexibility requirements for residual load fluctuations, which need to be studied at hourly, or ideally sub hourly, time intervals [9].

A unit commitment model is used here, adapted to the island of Ireland in the year 2030 at an hourly time resolution, under the assumption that wind and solar installed capacity rises dramatically to meet near-term national energy targets [3]. Synchronous condensers supplement a dynamic RoCoF constraint, three regionally dispersed large conventional units ensure voltage stability and reduce the likelihood of network overloads, while various forms of flexibility enhance the system's ability to respond to frequency deviations, or a sudden change in a single infeed or outfeed, with a very high share of wind and solar generation. In 2030, renewables are intended to meet 80% of electricity consumption on the island, with sectoral emissions falling to 3 $MtCO_2$eq. However, our simulations indicate that meeting this ambition may be challenging, as emissions only fall to 4.7 $MtCO_2$eq.

Economically, system flexibility affects the value of renewables operating in the market [10]. With greater availability of flexible resources, the reduced variability of wind and solar enhances their profitability [11]. A study in central Europe found that solar power benefited more from storage, whereas interconnection was better suited to wind [12]. Flexible loads have been found to be optimally used for peak shaving, rather than for renewable integration [13], [14].

The remainder of the paper is structured as follows: Section 2 introduces the optimisation model, followed by an outline of the generation mix and demand portfolios, and assumptions regarding electrification of heat and transport sectors in Section 3. Section 4 presents the results and discussion, and Section 5 concludes.

II. MODEL DESCRIPTION AND INPUT DATA

The unit commitment and economic dispatch model Backbone [15] is a mixed integer linear programming model with adaptable rolling planning to determine the least cost generation mix to meet a given load profile every 24 hours, with a 12 hour look ahead replicating perfectly competitive day ahead market structures. Full knowledge of future weather and load variation is assumed, with the flexibility requirements to meet unforeseen changes due to forecasting errors not of interest here.

Backbone represents different energy types in individual sub-systems within their own 'grids'. An energy balance is enforced at connected 'nodes' within the grids. Each node has its own units, operating reserve and spill capability. Costs minimised in the objective function include start-up costs ($u^{s\text{-}u}$), fuel costs (u^{fuel}), carbon costs (u^{carbon}) and penalty costs (u^{pen}) for energy imbalances or for violations of reserve requirements, at a node:

$$v^{obj} = \sum\nolimits_{\in T} \left(u_t^{s\text{-}u} + u_t^{fuel} + u_t^{carbon} + u_t^{pen} \right) \tag{1}$$

The developed model of the electricity grid connects the three separate nodes of Ireland (All Island), Great Britain (GB) and France. The All Island generation portfolio is based on Ireland's Climate Action Plan 2023 (CAP23) and generation scenarios for 2030 published by the transmission system operators (TSOs) in the North and South of Ireland [16]. As coal and peat plants are decommissioned, natural gas represents the only fossil fuel used for power generation in the Republic of Ireland by 2030. The gas price rises in line with assumptions from the EU's Reference Scenario, with some seasonal variation taken from [17]. The EU ETS carbon price is set at €100 per tonne in 2030.

TABLE I. ALL ISLAND GENERATION PORTFOLIO

Technology/fuel type	Installed capacity, MW
Gas CCGT / OCGT	4,650 / 2,630
On / offshore wind	8,150 / 7,100
Hydro / Marine	246 / 10
Biomass / CHP & waste	404 / 400
Utility / rooftop solar	5,500 / 2,500
Pumped storage	292
Battery storage 30 min / 2 h	400 / 1,050
DSM	800
DC Interconnection	2,150

Operational constraints for individual units include generator capability limits and reserve capabilities. The required reserve speed of response varies between primary and tertiary categories based on 75% and 100% of the largest single infeed [4]. To ensure frequency stability, separate constraints ensure a maximum 95% system non-synchronous penetration (SNSP), a dynamic rate of change of frequency (RoCoF) limit of 1 Hz/sec, where $\Delta P_{i,t}$ represents the potential loss of a plant infeed or interconnector trading (2), and a minimum of three regionally distributed large gas units on at all times (3):

$$2 \times RoCoF \times \sum\nolimits_{\in T} (H_{i,t} \times S_{i,t}) \geq NominalFreq \times \Delta P_{i,t} \tag{2}$$

$$\sum\nolimits_{\in T} \left(u_t^{onlineGroupMultiplier} \right) \times v_t^{online} \leq u_t^{onlineGroupTotal} \tag{3}$$

The product of generators' inertial constant, H_i, and apparent power rating, S_i, represents their stored rotational inertia, and is provided by online conventional generation and hydro (run of river and pumped) in the base case.

A. Renewable capacity

Ireland accelerated its renewable energy programme in the early 2000s with a focus on onshore wind development, reaching 4.3 GW capacity in the Republic of Ireland at the end of 2021, or 5.5 GW on the island as a whole. To meet ever more ambitious greenhouse gas emissions targets, Ireland's latest CAP23 aims for investment in offshore wind and solar photovoltaics (PV) to match that of onshore wind by 2030. In addition to a total of 9 GW of onshore wind by 2030, CAP23 includes at least 5 GW of new offshore wind capacity (as well as 2 GW of offshore wind for hydrogen production, although this is not modelled here) and 8 GW of new solar PV capacity.

Weather data for 2030 is based on 2015 regional values for wind speed and solar irradiation in Ireland. Capacity factors are from the Renewables Ninja dataset and are split between existing, medium term and long term, recognising future wind turbine / PV panel sizes, technological advances and likely development locations [18]. The overall capacity factor in 2030 has been scaled to match EirGrid and SONI assumptions of 35% for onshore wind and 45% for offshore wind.

B. Flexible resources: Gas plants, storage & interconnectors

The CAP23 targets 2 GW of new gas-fired generation to ensure sufficient flexible capacity to meet periods of low variable renewables. It is assumed that 7 new small open cycle gas turbines (OCGT) plants totalling 1.6 GW and one larger 400 MW combined cycle gas turbine (CCGT) plant are built. Most other existing gas plants continue to be operational. Batteries and pumped hydro act as another key flexibility source. Storage is a source of contingency reserve and/or arbitrage, whereby excess electricity can be stored and released as needed. It can also be used for blackstart conditions, voltage regulation and managing network congestion. On top of the existing 292 MW of pumped hydro storage (6hr), there is another 400 MW of 30 minute battery storage, and 1050 MW of 2hr batteries, based on TSO storage projections for Ireland in 2030 [16]. When charged, batteries and pumped hydro provide upward primary and tertiary reserve between 20% and 50% of full capacity in the model.

Interconnectors play a key role in future systems by facilitating access to flexible resources and centres of demand. With market coupling, at periods of very high renewables and low prices, excess supply can be exported in well-connected grids. Interconnector capacity is limited in isolated systems however. There are currently two HDVC interconnectors between the island of Ireland and Great Britain, totalling 950 MW capacity. By 2030, the interconnection capacity to Great Britain and mainland Europe is expected to at least double, with a new 500 MW 'Green Link' interconnector to Great Britain (GB) and a 700 MW 'Celtic interconnector' between Ireland and France. Each interconnector provides up to 75 MW of reserve.

C. Additional technologies: synchronous condensers, medium duration storage and demand response

A number of additional scenarios consider the individual and joint curtailment and production cost impact of synchronous condensers (SCs), medium duration storage and demand response from sector coupling with the heat, transport and industrial sectors. SCs supply reactive current to support the local voltage. As rotating machines, they can also provide inertia to stabilise high variable renewable power systems, allowing for units that are constrained online solely for inertial requirements to switch off. Six high-inertia synchronous condensers (2*500 / 2*1250 / 2*2500 MWs) are added to the system to supplement rotational inertia without relying on relatively high cost conventional plant [19]. Medium duration storage is defined here as storage capacity for up to six hours with 90% round trip efficiency. Medium duration storage technology options have traditionally been limited by geographic suitability for pumped hydro or compressed air energy storage, however, newer possibilities with less locational constraints, such as zinc batteries, flow batteries, or thermal storage, are in various stages of development [20].

Load shifting using various forms of storage on the demand side (batteries in EVs, or hot water tanks with heat pumps) is also tested under the optimistic assumption that 60% of residential and commercial heat pumps, 60% of passenger and commercial electric vehicles, and 15% of large energy users fixed load, are actively engaged in load shifting to avail of daily least cost marginal prices. Total electricity demand on the island is projected to increase by almost 30% by 2030, driven by economic and household growth, new data centres (which could account for up to 23% of total Irish electricity demand by 2030), and the electrification of heat and transport [21]. Taken together, flexible loads in the model amount to 16% of total demand by 2030 and range from between 1.7 TWh from data centres to 2.5 TWh from heat pumps. Each load has markedly different hourly and seasonal profiles, which has advantages for providing flexibility at different times of the day and year.

TABLE II. DEMAND SHIFTING CAPABILITY ASSUMPTIONS

	Residential HPs	**Commercial HPs**	**Passenger EVs**	**Commercial EV**	**Data centres**
Peak installed capacity (MW)	1459	597	805	84	1290
Annual energy demand (TWh)	3.1	1.1	3.2	0.4	11.3
Controllable demand	60%	60%	60%	60%	15%
Storage (MWh)	1456	645	1936	224	3032

III. CASE STUDY RESULTS

A. Conventional plant operation and system cost savings

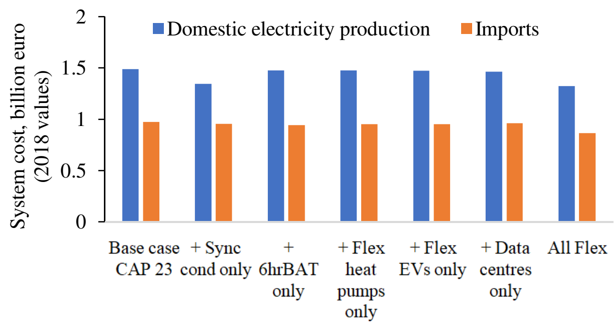

Figure 1. Conventional plant use under different flexibility scenarios

System costs are split between electricity produced locally and the cost of imports. The cost of domestic electricity generation, which captures the start-up, fuel and emissions costs for all conventional generating units in Ireland in 2030, falls 13% with all flexibility. Despite considerable investment costs for storage, and electrification of heat and transport, it is instructive to consider the value of these technologies in reducing the total cost of electricity generation. There is evidence that medium duration batteries, data centres and flexible heat pumps in the winter are utilised for peak shaving, with the load shifting away from expensive peak hours, reducing OCGT use by 90%. Taken together, synchronous condensers and the flexibility measures chosen do not greatly erode each other's savings effects, suggesting complementary benefits of different shiftable loads, with a cumulative savings impact of €165M domestically and €110M in imports.

B. Renewable generation and curtailment

As the amount of wind and solar power produced begins to outstrip domestic demand for longer periods, curtailment of excess renewable power inevitably rises. Net load, or demand minus wind and solar generation (excluding must-run generation or other operational constraints), turns negative for approximately 50% of the year in the 2030 scenarios. Figure 2 illustrates the seasonal variation in demand minus available renewable power. On average, in the spring and summer, wind and solar generation exceeds the Irish load by 3 GW in the early afternoon, and is, on average, in a 2 GW deficit during peak hours. In the winter period, excess wind power is observed for longer periods overnight when the demand is low, with instances when wind curtailment alone can reach up to 10 GW.

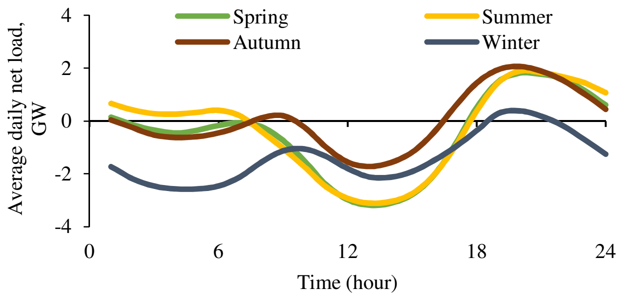

Figure 2. Average daily net load profiles by season, 2030.

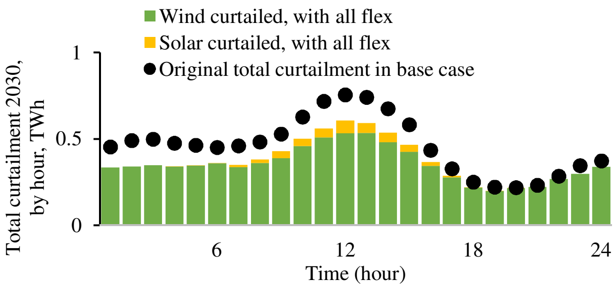

Figure 3. Total curtailment in 2030, grouped by hour, and the reduction in curtailment from additional flexibility.

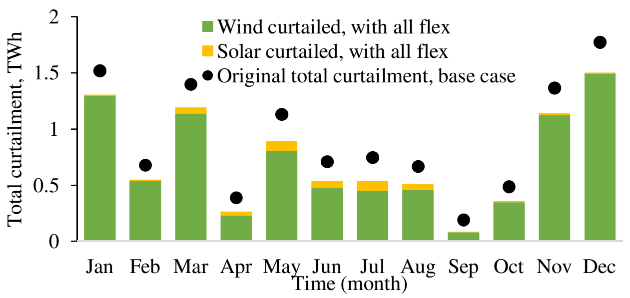

Figure 4. Total curtailment in 2030, grouped by month, and the reduction in curtailment from additional flexibility.

If the assumption of full export capacity on all interconnectors from Ireland during times of high renewables is included, there is still oversupply of renewable power for approximately one quarter of the year. As such, compared to 3% curtailment of wind power on the island in 2021, curtailment reaches 21% of renewables by 2030 in the base scenario. Increasing the flexibility of loads has a slight impact on the ability to utilise available renewable power, reducing overall curtailment by 2%. Load shifting is particularly beneficial for absorbing excess solar power, when demand is able to move from the evening to the afternoon, but is less effective at times of very high shares of wind (see Figures 4, 5). Scaling up of load shifting by 50% and 100% was found to be relatively ineffective at reducing curtailment much further, suggesting alternative solutions are needed to address the oversupply of renewables or curtailment due to system security reasons.

The most effective technology for reducing curtailment (and system costs) in our model was synchronous condensers. Displacing the requirement for conventional generation to meet minimum inertia and RoCoF constraints allowed an additional 1.5 TWh of renewable power to reach the load, and reduced the total annual curtailment of wind power by 11%. The latest operational constraints published by the TSO to ensure the integrity of the future electrical grid include a minimum number of units on at all times for system support, a RoCoF limit, an SNSP limit, and various reserve requirements to manage frequency deviations, as discussed in section II. Relaxing some of these constraints through localised stability and network constraints may offer another approach to reducing curtailment levels, on a case by case basis. Another possibility is utilising curtailed wind power for reserve, which will be explored further in future work.

The duration of curtailment events in our chosen wind year lasted up to 3 days. With all flexibility options added there were eleven instances of high wind curtailment events lasting over 48 hours, each curtailing between 160-380 GWh of wind power (see Figure 6), and together accounting for around one third of total wind curtailment across the year. Seasonal storage technologies with capacity beyond 10 hours, such as hydrogen and methane (power to gas), may head some way towards reducing curtailment due to imbalances during extended high wind periods which last the course of several days [22]. Alternatively, investment in additional interconnection would enable further export of renewables during times of high wind. The question then becomes whether it is more prudent to compensate developers for unsold electricity (or reduce the installed capacity target to more closely align with domestic requirements), or to invest in greater long term storage or transmission capacity to enable export of low carbon sources of energy produced in Ireland.

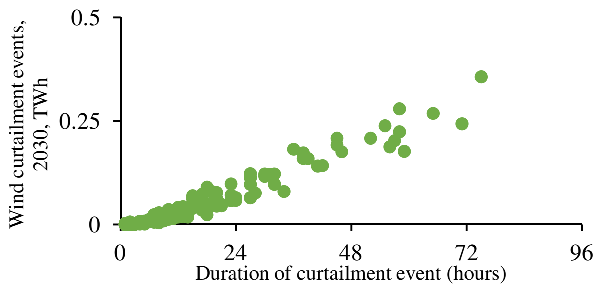

Figure 5. Duration and size of curtailment events

C. Demand response, prices and value factors

Post load shifting, the average weighted wholesale price of electricity for heat pumps falls from 67 c/kWh to 56 c/kWh. Electric vehicle customers experience higher savings with the weighted wholesale price falling from 71 c/kWh to 53 c/kWh. Future green electricity tariffs schemes proposed in CAP 23 should enable participants to receive lower prices as they shift their load, however, all market users should also benefit from lower electricity costs during peak hours, which fall from a peak price of 216 c/kWh to 175 c/kWh with all mitigation strategies included, due to less reliance on more expensive OCGT plants.

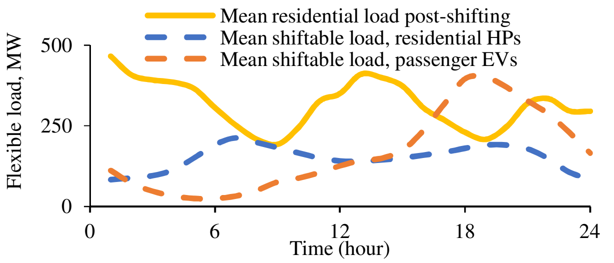

Figure 7. Average annual flexible residential heat pump and electric vehicle load, pre and post shifting.

As flexibility increases, the value factors for different fuel types, which represent the weighted spot price relative to the average wholesale price [8], start to shift. Peaking generation, in particular, becomes less profitable on the wholesale market as the system moves towards a greater reliance on a combination of larger CCGT plant, synchronous condensers for inertial response, and storage and flexible demand. Solar also benefits, with its value factor moving from below 1 to above 1. However, the value factor for wind power remains low at around 0.65, indicative of continued excess wind at times and the cannibalisation of its own profits.

IV. Economics and Markets

Renewable energy, battery storage, interconnectors and low carbon heat and transport are typified by high upfront costs which need to be recovered through future market returns (or savings for consumers). However, within the system, and excluding any external factors which affect day-to-day fossil fuel costs, the day ahead marginal electricity price in our model can vary depending on operational constraints, weather patterns, the renewable portfolio and the level of flexibility.

As loads become capable of following the price, traditional peaks reduce which will likely have feedback from competing flexibility providers. Peaking plants may be less utilised, while lower price spreads on the day ahead market will reduce the arbitrage margin for storage operators. On the other hand, a higher variable renewable energy share leads to more periods of near zero prices, as well as increased spot price volatility, but without the same regular trends. Uncertain energy market outcomes, such as these, increase the complexity of investment making decisions.

The results from our analysis also highlight very high curtailment levels, of at least 16%, with the proposed wind and solar installed capacity by 2030, even with various forms of flexibility included. Curtailment reduces the effective capacity factor of renewables. Since the energy cost per unit of output is inversely proportional to its capacity factor, high curtailment substantially increases the cost of variable renewables, which could drive up the bidding prices of renewable developers to recoup their investments in the wholesale market. The latest iteration of Ireland's Renewable Energy Support Scheme (RESS) has recognised the curtailment risk for developers, and has proposed an 'unrealised available energy compensation' to support developers for curtailment [23]. However, there is a risk that such a scheme will distort the market signal for developers to co-invest in storage to maintain their competitiveness and profitability. This could have negative implications for both the subsidy cost of wind and/or storage for consumers and the rate of development of storage. For instance, a recent Irish study found that investing in a power-to-gas unit, with a very high share of annual generation from wind, was unprofitable on its own, but if a developer invests in both a wind farm and power to gas plant, both technologies together become profitable [24].

Many technologies which are needed for a more flexible electricity system, such as faster acting CCGT plants or battery storage, are capital-intensive and insufficiently remunerated by the energy market alone. As a result, revenue streams are shifting towards greater recognition of the value of shifting energy, fast frequency reserve, generation adequacy, etc. [25]. Capacity mechanisms and/or ancillary payments are available in certain European regions, and state aid is available for grid-scale storage projects, but on a case-by-case basis. In Ireland, regulated revenue streams for system services, including reserves to address frequency requirements, have existed since 2016, with a new day-ahead auction for system services due in 2026 [26]. As the share of variable renewables dramatically increases in Ireland, a shift away from reliance on the day ahead spot market for revenue generation, and toward multiple markets supporting various system elements, including flexibility, is likely. As energy markets become increasingly multi-layered, however, greater certainty will be important to enhance investment in flexibility and reduce the financing cost.

V. Conclusion and Future Work

The impact of very high variable renewables and strategies for increasing grid flexibility in an isolated system have been considered here. The island of Ireland has set ambitious targets for 80% of electricity consumption to come primarily from wind and solar power by 2030. Including synchronous condensers and various forms of flexibility from medium duration storage and demand response has led to a system cost savings of 11% due to displacement of conventional plant for inertial requirements and peak energy provision.

Given the very high investment costs for storage, and decarbonisation objectives for the heat and transport sectors, it is useful to understand their system-wide value, and the importance of developing appropriate mechanisms to reward investment in flexibility. It is seen that unacceptably high levels of curtailment are obtained even with added flexibility, at 16%, although the RESS mechanism tends to protect developers in such situations. Future work will consider actions that may reduce these levels further, such as adopting case-based, and more localised, constraints to impose stability and utilising curtailed wind as a form of reserve.

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