# A Market Assessment of Distributed Battery Energy Storage to Facilitate Higher Renewable Penetration in an Isolated Power System

**NEIL MCILWAINE**[1], (Member, IEEE), **AOIFE M. FOLEY**[2,3,4], (Senior Member, IEEE),
**DLZAR AL KEZ**[1,5], (Graduate Student Member, IEEE), **ROBERT BEST**[1], (Member, IEEE),
**XI LU**[6], **AND CHONGYU ZHANG**[6]

[1]School of Electronics, Electrical Engineering and Computer Science, Queen's University Belfast, Belfast BT9 5AH, U.K.
[2]School of Mechanical and Aerospace Engineering, Queen's University Belfast, Belfast BT7 1NN, U.K.
[3]Department of Civil, Structural and Environmental Engineering, Trinity College Dublin, The University of Dublin, Dublin 2, DO2 PN40 Ireland
[4]Bryden Centre, School of Chemistry and Chemical Engineering, Queen's University Belfast, Belfast BT7 1NN, U.K.
[5]Electrical Engineering Department, University of Sulaimani, Sulaymaniyah 46001, Iraq
[6]School of Environment, Tsinghua University, Beijing 100190, China

Corresponding author: Neil McIlwaine (nmcilwaine01@qub.ac.uk)

**ABSTRACT** Power systems with a high share of renewables require additional ancillary services to operate safely and reliably. System operators are introducing schemes to attract investment in technology which will provide ancillary services. Battery storage can provide some of these services but investment in equipment is required. This study investigates the potential benefits of energy storage and tests the market arrangements to attract investment. The study uses a combination of numerical and system analyses to test the financial performance. A dynamic economic dispatch model was used to evaluate the system costs and emission levels. A unit commitment model was used to measure the reserve cost. Both models use real-time load data for a region in the Irish electricity market. The ancillary service revenue is modelled based on actual renewable levels for the Irish system. The frequency and rate of change of frequency response are evaluated by introducing a disturbance to the system model with and without energy storage. The results were used to test investment opportunities using established financial appraisal techniques.

**INDEX TERMS** Battery energy storage, frequency nadir, rate of change of frequency, renewables, ancillary services, financial feasibility.

## ACRONYMS

| | |
|---|---|
| BESS | Battery energy storage system. |
| CCGT | Combined cycle gas turbine. |
| DED | Dynamic economic despatch. |
| DNO | Distribution network operator. |
| DS3 | Delivering a secure sustainable electricity system. |
| EV | Electric vehicle. |
| FFR | Fast frequency response. |
| IRR | Internal rate of return. |
| MW | Megawatt. |
| NI | Northern Ireland. |
| NPV | Net present value. |
| POR | Primary operating reserve. |
| PV | Photovoltaic. |
| PWM | Pulse width modulation. |
| RES-E | Renewable energy source - Electrical. |
| ROA | Return on assets. |
| ROCOF | Rate of Change of Frequency. |
| ROI | Republic of Ireland. |
| RRD | Replacement reserve desynchronized. |

| RRS | Replacement reserve synchronized. |
| SNSP | System non- synchronous penetration. |
| SOR | Secondary operating reserve. |
| TOR | Tertiary operating reserve. |
| UCM | Unit commitment model. |
| UFLS | Under frequency load shedding. |
| UK | United Kingdom. |
| US | United States. |

## I. INTRODUCTION

Global decarbonization is driven by the Paris Agreement [1] and the Glasgow Climate Pact [2]. Countries signed up to this agreement are combating climate change by setting targets for renewable electricity generation. In the United Kingdom (UK) a target has been set for net zero emissions by 2050 [3]. On the island of Ireland, the electricity system is jointly operated in both the Republic of Ireland (ROI) and Northern Ireland (NI). In both jurisdictions there is a shared target for 70% of the electricity generated, to be sourced from renewable energy sources (RES-E) by 2030 [4]. To deliver this target the system operators in ROI and NI estimate an additional 10 GW of RES-E will be required. Ireland, located northwest of continental Europe, is ideally placed to generate RES-E using wind turbine technology. Currently there is 5.5 GW of installed wind capacity [5]. In February 2021, during a system trial on the Ireland electricity system, the system non-synchronous penetration (SNSP) was operated at 70% [4]. However, system operation at this level of renewable energy with an installed dispatchable capacity of 10 GW, has created challenges for the system operator such as frequency regulation, voltage support and reserve [6]. The transition from large fossil fuel synchronous generators to renewables mainly delivered by wind turbines has resulted in a decrease of system inertia. During system disturbances at a high SNSP, the rate of change of frequency (ROCOF) levels can be a risk to system stability, with the potential to mechanically damage connected synchronous machines [7]. Additionally, with fewer available dispatchable machines available, the facility for frequency regulation and voltage support is diminished.

There is extensive market and economic research on countries which are transitioning to a renewable generation system integrated with battery energy storage. The authors in [8] carried out a techno-economic assessment of storage systems by considering the life cycle cost of storage and the levelized cost of energy over short-, medium- and long-term timescales, with the cost models proposed serving as a useful tool for selecting the correct type of energy storage based on the required benefits. By taking on the mantle of an investor a study assessing a battery business recommended effective policy changes and incentives as the catalyst to development of battery energy storage, however this study was limited to the market in the Great Britain regions of the UK [9]. The results of an assessment of the impact of battery storage in the role of peaking capacity in the United States (US) market, found potential for storage durations of 10 hours or

less in areas of high renewable penetration [10]. This study, associated only with the US market, was prompted by a government order requiring market operators to allow storage to participate in the capacity market. A study in [11] evaluates battery storage competing in the day ahead and frequency restoration markets for the current German electricity system, concluding that high power batteries with the ability to provide short term power maximizes revenues. An evaluation of the deployment of PV (photovoltaic) with and without battery storage in residences in the Portuguese market used a capital cost of €492/kWh and found that PV plus storage was not feasible, but predicted an improvement in profitability as prices continued to fall [12]. An investigation of the role of residential battery storage coupled with PV in an urban area of Australia, addressed network issues, with a positive finding that voltage issues (high and low) are moderated, however, only marginal household gains could be obtained chiefly by the sole use of PV for charging [13]. The technical benefits of battery storage in the Australian power systems were investigated in [14], concluding that a storage capacity of 15% of installed generation can both reduce the frequency zenith and introduce a dampening effect thus reducing the ROCOF. The scenario used was a system separation event which occurred on the Australian grid with this research indicating the potential of battery storage in limiting frequency rise. In NI the grid has a high voltage direct current link to Great Britain and a high voltage synchronous link to the ROI with the potential for system separation resulting in frequency exceeding upper limits [15]. A grid scale study compares the profit of battery and thermal storage integrated with a wind farm, with the battery system returning the most favourable results and an additional benefit of a reduction in curtailment [16]. In NI the development of wind generation has outpaced the grid system resulting in curtailment being imposed to comply with grid system requirements [17]. A review paper examining behind-the-meter energy storage in China proposes policy recommendations based on lessons learned from the approach in the US and specifically in California [18].

The literature review reveals that recent studies are bespoke and, in most cases, relate to the storage development stage, grid system characteristics, available schemes and government direction pertaining to the region being assessed. Northern Ireland is an example of an isolated but well-developed power system with a high share of renewables. The UK government Net Zero Strategy [19] will drive further renewable development in NI where the climatic conditions for wind generation are very suitable. To attract investment, regulator and system operator schemes must provide an adequate return. It is here that the research gap exists as there is a disconnect between the value design of incentive schemes and the current cost of investment. In other words, the technical and environmental benefits of storage are not being costed accurately enough when set against capital investment costs. The objective of this paper is to analyse the deployment of battery energy storage to test the current market arrangements on the island of Ireland, designed to

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support increased renewable generation, and the response to a system disturbance. Revenue from the existing incentive schemes, which are designed to attract system services and to limit network build out, will be measured against estimated capital investment to determine financial feasibility. The technical impact on system disturbance, provision of reserve and response to system disturbance will be studied. The added value of this work is the flexibility of the modelling which can be adapted for different regions, SNSP levels and incentive schemes.

The key contributions of this paper are:

(a) The linkage between the system services scheme, actual system data and revenue. The developed models are flexible and readily adaptable to other regions.

(b) Testing of battery storage in a system operator incentive scheme designed to limit network build out.

(c) Assessment of the technical benefits of distributed battery storage in a region with high renewables.

(d) Complete financial analysis of incentive schemes using established analysis tools.

Following this introduction, the paper is set out as follows: Section II describes the modelling methodology; Section III reports on the results, Section IV is a discussion on the results and finally Section V presents the conclusion and comments on the proposed future work.

## II. METHODOLOGY

### A. SYSTEM SERVICES BACKGROUND

In 2011 the system operators in Ireland introduced a scheme to address power quality issues by targeting a range of ancillary services to create the conditions required to operate at an SNSP of up to 75% [20]. These services are part of a program called DS3 which is an acronym for "Delivering a Secure Sustainable Electricity System". This range of ancillary services is in addition to the normal power quality services of primary, secondary, and tertiary operating reserve (POR, SOR and TOR), voltage support, and synchronized and de-synchronized replacement reserve (RRS and RRD). The change in SNSP on the island of Ireland during the period 2008 to 2021 is illustrated in Figure 1 [21]. The plot shows a yearly increase in the gap between the 25th and 75th percentile from 30% to 80%, driven by the increase in wind generation.

In 2021, the Distribution Network Operator (DNO) in Northern Ireland introduced a pilot scheme called FLEX [22]. The objective of this scheme is to set up contracts for products which are used to resolve network congestion and ultimately avoid further network build out. This is a response to the anticipated electrification of heating and transport [23], [24]. In the FLEX scheme there are three basic products labelled 'sustain', 'secure' and 'dynamic'. The 'sustain' products are scheduled during periods when the system is intact and are procured well in advance for a pre-arranged import or export of power for a pre-defined time, for example load reduction at peak period. The 'secure' products are used to support
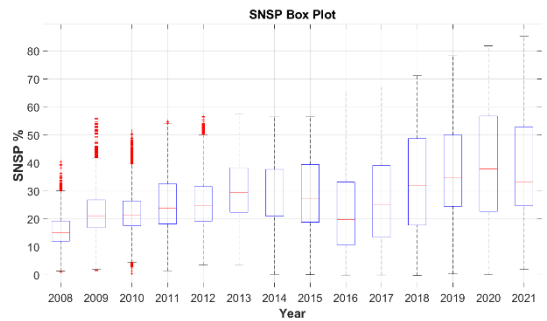


**FIGURE 1.** Changes in SNSP due to growth of wind generation in Ireland from 2008 to 2021.

system security if a network limit is forecasted to be breached. Utilization of the 'secure' product is instructed close to the forecasted event with an example being a severe weather event. The 'dynamic' products are used to support the system following a fault, for example a network fault causing overload of the remaining system. The minimum level of bid is 50 kW however this can be an aggregate or a single asset. There is no lower limit on the capacity of individual assets which make up the aggregated total. Table 1 shows the payment structure for the three product classes. The availability fee is for each MW made available per hour during the pre-arranged time. The utilization fee is paid for every MWh of energy delivered during the utilization event.

**TABLE 1.** Flex payment type and product description.

| Product class | Sustain | Secure | Dynamic |
|---|---|---|---|
| Description | Scheduled | Pre-fault | Post-fault |
| Availability fee | n/a | ✓ | ✓ |
| Utilization fee | ✓ | ✓ | ✓ |

The ROI government has plans for further expansion of wind generation as set out in their Climate Action Plan 2019 [25]. The implementation actions in this plan which are pertinent to this study are briefly described as follows: delivery of 3.5 GW of offshore wind by 2030 and, electrification of heat triggered by a ban on the installation of domestic oil and gas boilers by 2022 and 2025, respectively. Additionally, electrification of transport is facilitated by the installation of a charging network to support 800,000 electric vehicles (EV) by 2030 [26]. This is an aggressive target considering that there are currently 2.7 million vehicles in the ROI [27]. This level of renewable generation and the increased load due to electrification of heating and transport will rely on specific measures, like energy storage and fast start generation being put in place to ensure stable system operation. Weather events such as a winter high-pressure system with low wind and low temperatures will require back up generation in the form of 'clean' fossil fuelled generation. There is no global definition for 'clean' fossil fuel, most likely as the very nature of any carbon combustion process will produce $CO_2$ plus other

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pollutants. However, the combustion of natural gas is cleaner than that of oil or coal because of the lower emission levels of sulphur dioxide, nitrogen dioxide and particulates [28]. Electricity generation technology such as a combined cycle gas turbine (CCGT) can operate at efficiencies of more than 50% resulting in a lower carbon intensity compared to 33% by using oil or coal in a conventional Rankine cycle boiler-turbine-condenser arrangement. The system operator for the Irish market has tendered for and awarded 220 MW (de-rated) of 'clean' gas fired generation to be completed by 2023 at Kilroot Power Station, Carrickfergus, Co. Antrim [29].

A battery energy storage system (BESS) is considered as a balancing technology for increasing the levels of renewable generation. In 2016 a 10 MW (5 MWh) facility at Kilroot Power Station in NI was installed, primarily set up as a pilot scheme to react to system frequency changes by charging or discharging as required, in effect providing both frequency regulation and smoothing [30]. There is indication of other grid scale projects for energy storage with a 50 MW battery commissioned in November 2020 at Drumkee in NI [31]. Although transmission level energy storage installations are growing, there is little evidence of mass energy storage at the distribution level becoming a counter-balancing source to intermittent renewable generation. The system operator approach is to source ancillary services balancing products with no particular focus on the technology provider. The governmental approach is generally target driven to encourage renewable generation and reduce emissions. The term transactive energy is becoming more prevalent where control mechanisms and markets are combined to create a bi-directional flow of electricity right down to the distribution level [32]. However, transactive energy at the distribution level is in its infancy due to the diversity and complexity surrounding its implementation and the untested use of energy storage using the current market conditions.

To perform the modelling over one year, publicly available data from the Ireland market are used covering the period from January 2020 to December 2020 [21]. The models are adaptable should the formulae or revenue settings change.

### 1) DS3
The DS3 program procures 14 system services designed to enable the electricity system to operate at high levels of SNSP [20]. To be eligible for payment, a contracted device providing a service must be synchronized to the system except for the replacement reserve (desynchronized) product. A temporal scarcity scalar multiplier is used in the revenue calculation to reflect the escalating value of these services as SNSP increases. The magnitudes of these scalars at specific SNSP ranges and the ancillary system services parameters are listed in Table 2 [33]. Payments are calculated for every half hour period during which a particular product is offered. Typically for each service the payment is the product of the available volume, payment rate and scaling factor. The scaling factor is the product of further scalars that are appropriate to the service. The fast frequency response (FFR) product

is specifically aimed at countering the increased ROCOF in systems with a high share of renewables. The FFR has additional scalars to incentivize performance. If a providing unit can deliver all the following, FFR, POR, SOR and TOR1, during a half hour period, the FFR Continuous Scalar is set to 1.5. The delivery time for FFR is set between 2 and 10 seconds with response initiation between event commencement and 2 seconds. If the FFR provider can respond in less than 0.15 seconds from the start of the event the FFR Fast Response Scalar is set to 3, reducing to 1 for a response up to 2 seconds. The modelling in this work assumes an FFR Continuous Scalar of 1.5 and a Fast Response Scalar of 3. Therefore, when the SNSP is > 70% resulting in a temporal scalar of 6.3, the maximum overall scalar achievable for FFR is 28.35 (i.e., $1.5 \times 3 \times 6.3$). The potential to receive revenues based on the probability of this scalar factor occurring will be of great interest to investors. Battery storage connected at the distribution level can provide several of these services.

### 2) FLEX
The FLEX pilot program is initially procuring 40.3 MW of services with most of these services connected at 11 kV or below. A 100 kW/400 kWh battery is proposed for this study and is modelled for a typical year for all three of the tendered products namely sustain, secure and dynamic. The exact rates are not yet known so a range of rates are used to give an indicative revenue. The utilisation estimates quoted in the initial offer literature are used [34]. For both the FLEX and DS3, the 100 kW/400 kWh battery connected at distribution level is initially modelled to determine the revenue from the applicable products. This power to energy ratio is chosen because the FLEX products must be delivered for up to 4 hours. However, DS3 products typically do not require this level of energy delivery but for the basis of this study it is assumed that a single battery will deliver both products.

### B. FREQUENCY RESPONSE
This section describes the methodology implemented to investigate the performance of a power system frequency with and without 20MW of battery energy storage at different arrangements of aggregation. The detailed full dynamic model of the modified standard IEEE 14 Bus system is developed in DIgSILENT PowerFactory. As shown in Figure 2, the IEEE 14-bus modified test system consists of five synchronous machines, three of which are synchronous condensers to maintain the wide area system voltage stability [35]. There are 14 buses, 16 transmission lines, 3 transformers, and 7 constant impedance loads. The total load demand is 259 MW and 73.5 MVAr. In the default topology of the standard IEEE 14 Bus system, all synchronous machines are integrated into the high voltage buses which operate at 132 kV and 220 kV. It is important to note that all synchronous machines are equipped with an IEEE type-1 exciter system. Furthermore, all synchronous generators are equipped with the WSCC Type G governor models to maintain system frequency deviations within permissible

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**TABLE 2.** Magnitude of ancillary system services payments at specific SNSP levels.

| Service | Acronym | Current rate £ | Delivery time | Temporal scarcity scalar | | | |
|---|---|---|---|---|---|---|---|
| | | | | A* | B* | C* | D* |
| Primary op. reserve | POR | £2.95 / MWh | 5-15s | 1 | 1 | 4.7 | 6.3 |
| Secondary op. reserve | SOR | £1.78 / MWh | 15-90s | 1 | 1 | 4.7 | 6.3 |
| Tertiary op. reserve | TOR1 | 1.41 / MWh | 90s-5m | 1 | 1 | 4.7 | 6.3 |
| Tertiary op. reserve | TOR2 | 1.13 / MWh | 5m-20m | 1 | 1 | 4.7 | 6.3 |
| Sync inertial response | SIR | £0.0045/MWs²h | n/a | 1 | 1 | 4.7 | 6.3 |
| Fast freq. reserve | FFR | £1.97 / MWh | 2-10s | 0 | 1 | 4.7 | 6.3 |
| Replacement reserve | RR | £0.23 (sync.) £0.51 (desync.) | 20m–1h | 1 | 1 | 4.7 | 6.3 |
| Ramping margin | RM1 | £0.11 / MWh | 1h | 1 | 1 | 4.7 | 6.3 |
| Ramping margin | RM2 | £0.16 / MWh | 3h | 1 | 1 | 4.7 | 6.3 |
| Ramping margin | RM3 | £0.15 / MWh | 8h | 1 | 1 | 4.7 | 6.3 |
| Steady state reactive power | SSRP | £0.21 / MWh | n/a | 1 | 1 | 4.7 | 6.3 |
| Dynamic reactive power | DRR | £0.04 / MWh | n/a | 0 | 0 | 0 | 6.3 |
| Fast post fault active power recovery | FPFAPR | £0.14 / MWh | n/a | 0 | 0 | 0 | 6.3 |

A* SNSP $\leq$ 50%

B* 50% < SNSP $\leq$ 60%

C* 60% < SNSP $\leq$ **70%**

D* SNSP > 70%



**FIGURE 2.** Modified 14 bus IEEE standard system used in the frequency response modeling.

ranges during disturbances. This model is used to evaluate the system frequency stability during transients as described in Section III B.

### 1) BATTERY STORAGE MODEL

The battery storage model consists of a battery bank, a three-phase bidirectional DC/AC converter, and a three-phase step up transformer connected to the electricity grid system [36]. The capacity of the battery limits the active power support for frequency management, whereas the capacity of the pulse width modulation (PWM) converter limits the reactive power support. Battery storage can support voltage and frequency because of its capability to control active and reactive power separately using two different current parameters on the
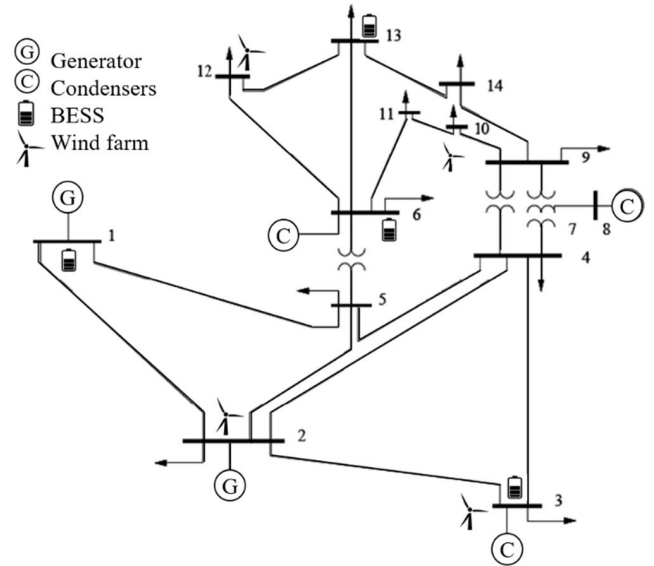
$d$ and $q$ axes within the converter. The basic battery controller comprises the following:

a) Frequency controller – outputs an active power reference $P_{ref}$.
b) Voltage controller – outputs a reactive power reference $Q_{ref}$.
c) Active PQ controller – outputs a PQ signal based on $P_{ref}$ and $Q_{ref}$.
d) Charge controller – the output from the PQ controller and the state of charge determines whether the battery is in charge or discharge mode.
e) Current controller – outputs a signal to the PWM Convertor based on the output of the charge controller.

Schematics of the overall battery, frequency and voltage controllers are shown in Figures 3, 4 and 5 respectively.

### C. DYNAMIC ECONOMIC DISPATCH/MINIMISATION OF FUEL COSTS

A dynamic economic dispatch (DED) model is used to test the economic production schedule for the dispatch of thermal units over a 24-hour period with and without aggregated battery energy storage of 20 MW [37]. The objective function of the DED is to minimise the total operating cost of generation while providing system load and adhering to all constraints. The constituent curves for generator costs are fuel cost, heat rate, change in input (fuel)/output (electrical), and incremental cost [38]. The resultant curve is generally represented as a quadratic equation (1) where C is the hourly production cost, P is the MW output and a, b and c are the generator cost coefficients.

$$C = aP^2 + bP + c \tag{1}$$

Similarly, the generator emissions are represented by the quadratic equation (2) where EM is the hourly total emissions
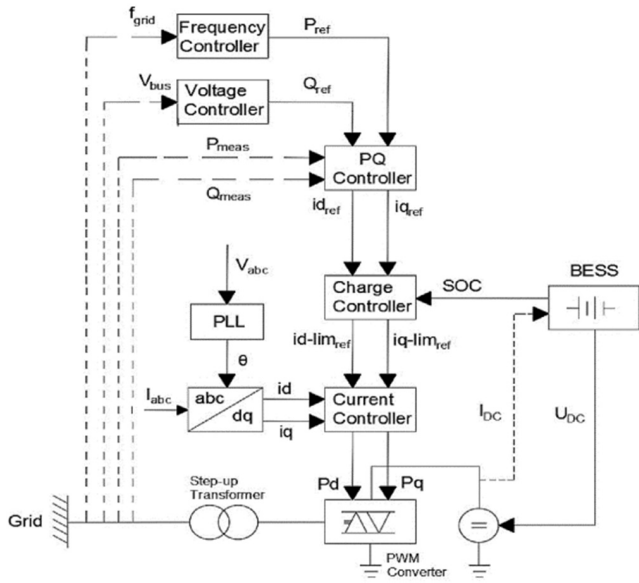
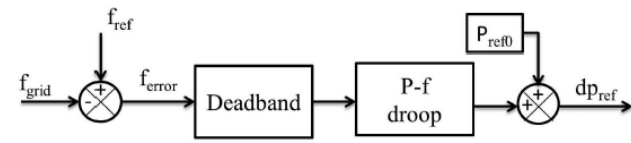**FIGURE 3.** Overall battery control system schematic.



**FIGURE 4.** Frequency controller implemented in the battery control system.
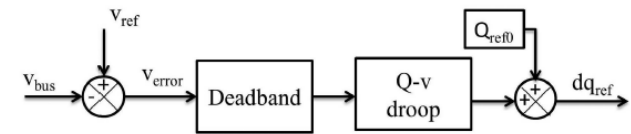


**FIGURE 5.** Voltage controller implemented in the battery control system.

in kg, P is the MW output and d, e and f are the generator emission coefficients.

$$EM = dP^2 + eP + f \quad (2)$$

The objective function is subject to the constraints of maximum and minimum generation limits, ramping rates, load balance, battery state of charge and maximum and minimum battery charge and discharge limits. The objective function for the DED model is given in (3) and the constraints in (5), (6), (7), (8), (9), (10), (11) and (12). The total generator emissions are given by (4).

$$min \, FC = \sum_{g,t} a_g P_{g,t}^2 + b_g P_{g,t} + c_g \quad \text{(minimise fuel cost)}$$
$$(3)$$

$$EM = \sum_{g,t} d_g P_{g,t}^2 + e_g P_{g,t} + f_g \quad \text{(emissions)} \quad (4)$$

$$P_g^{min} \le P_{g,t} \le P_g^{max} \quad \text{(power max. and min.)} \quad (5)$$

$$P_{g,t} - P_{g,t-1} \le RU_g \quad \text{(ramp up rate)} \quad (6)$$

$$P_{g,t-1} - P_{g,t} \le RD_g \quad \text{(ramp down rate)} \quad (7)$$

$$SOC_t = SOC_{t-1} + (P_t^c \eta_c - P_t^d / \eta_d) \Delta_t \quad \text{(state of charge)}$$
$$(8)$$

$$P_{min}^c \le P_t^c \le P_{max}^c \quad \text{(battery charge limits)} \quad (9)$$

$$P_{min}^d \le P_t^d \le P_{max}^d \quad \text{(battery discharge limits)} \quad (10)$$

$$SOC_{min} \le SOC_t \le SOC_{max} \quad \text{(state of charge limits)} \quad (11)$$

$$\sum_g P_{g,t} + P_t^d \ge L_t - P_t^c \quad \text{(load balance)} \quad (12)$$

| | |
|---|---|
| $FC$ | Total fuel cost (£/h) |
| $a_g, b_g, c_g$ | Fuel cost coefficients |
| EM | Total emissions (kg) |
| $d_g, e_g, f_g$ | Emission coefficients |
| $P_{g,t}$ | Power generated by unit $g$ (MW) and $RD_g$ |
| $RU_g$ | Ramping limits of unit $g$ (MW/h) |
| $SOC_t$ | Battery state of charge at time $t$ (MW) |
| $P^c$ | Power charged from grid to battery (MW) |
| $P^d$ | Power discharged from battery to grid (MW) |
| $\eta_c, \eta_d$ | Charge and discharge efficiencies (%) |
| $L_t$ | Electric demand at time $t$ (MW) |

### D. UNIT COMMITMENT MODEL/SYSTEM RESERVE COSTS

In this section a unit commitment model (UCM) is used to determine the cost of reserve [37]. Reserve is used by system operators to cover for sudden changes in demand. This type of cover is essential for systems with high levels of renewables. Traditionally a UCM is used to determine the most economical production schedule for generation using the standard parameters of fuel, start-up, shutdown, operating and maintenance, environmental costs, and specific unit parameters. For this study, the modelling is based on 10 generators typical of the base load fleet of fossil fuel machines on the island of Ireland where CCGT is the dominant technology. Therefore, operating and maintenance costs will be similar and will have no bearing on the model results and as such, have been omitted. The cost of reserve is calculated by running the model with and without reserve constraints. The objective function of a UCM is to minimise the total cost of bulk electricity production. The objective function is subject to the constraints of maximum and minimum generation limits, ramping rates, and load balance. In NI the spinning reserve requirement is 75% of the largest synchronously connected infeed on the island of Ireland [39]. A system constraint states that the minimum number of synchronous generators connected is three for NI and five for ROI. The spinning reserve requirement is shared via a single high voltage synchronous transmission line. The flexibility of the model allows for different levels of reserve to be set, however, in this study a reserve of 40% of demand was chosen to test the effect of battery storage. The objective function for the UCM model is given in (13) and the constraints in (14), (15) (16), (17), (18), (19), (20), (21), (22) and (23).

$$min \, OC = \sum_{g,t} FC_{g,t} + STC_{g,t} + SDC_{g,t}$$
$$\text{(minimise fuel cost)} \quad (13)$$

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$$\underline{P}_{g,t} \leq P_{g,t} \leq \overline{P}_{g,t} \quad \text{(time dependent min/max power)} \tag{14}$$

$$\overline{P}_{g,t} \leq P_g^{max}\left[u_{g,t} - z_{g,t+1}\right] + SD_g z_{g,t+1}$$
$$\text{(shut down in next hour)} \tag{15}$$

$$\overline{P}_{g,t} \leq P_{g,t-1} + RU_g u_{g,t-1} + SU_g y_{g,t}$$
$$\text{(ramp up after start up)} \tag{16}$$

$$P_{g,t} \geq P_{g,t}^{min} u_{g,t} \quad \text{(if on power greater than min)} \tag{17}$$

$$P_{g,t} \geq P_{g,t-1} - RD_g u_{g,t} - SD_g z_{g,t}$$
$$\text{(ramp down and shut down)} \tag{18}$$

$$y_{g,t} - z_{g,t} = u_{g,t} - u_{g,t-1} \quad \text{(on/off states)} \tag{19}$$

$$y_{g,t} + z_{g,t} \leq 1 \quad \text{(on/off states)} \tag{20}$$

$$\sum P_{g,t} \geq L_t \quad \text{(load balance)} \tag{21}$$

$$R_{g,t} \leq \overline{P}_{g,t} - P_{g,t} \quad \text{(reserve carried)} \tag{22}$$

$$\sum R_{g,t} \geq \gamma L_t \quad \text{(reserve as percentage of demand)} \tag{23}$$

| | |
|---|---|
| OC | Operating costs (£/h) |
| FC | Fuel cost of unit $g$ (£/h) |
| STC, SDC | Start-up and shut-down costs of unit $g$ (£/h) |
| $\underline{P}_{g,t}, P_{g,t}, \overline{P}_{g,t}$ | Time dependent power of unit $g$ (MW) |
| $u_{g,t}$ | On/off status of unit $g$ |
| $y_{g,t}$ | Start-up status of unit $g$ |
| $z_{g,t}$ | Shut-down status of unit $g$ and $RD_g$ |
| $RU_g$ | Ramping limits of unit $g$ (MW/h) and $SD_g$ |
| $SU_g$ | Start-up shut-down ramp limit unit $g$ (MW/h) |
| $L_t$ | Electric demand at time $t$ (MW) |
| $R_{g,t}$ | Online reserve provided by unit $g$ (MW) |
| $\gamma$ | Percentage factor (%) |

### E. FINANCIAL ANALYSIS VERSUS TECHNICAL BENEFIT

The methodology for the financial analysis uses the output from the various models described to compare the technical benefits and the potential financial revenues of battery energy storage at the distribution level. Using the results for potential revenue, an investment check is conducted using the following techniques, payback period, return on assets (ROA), net present value (NPV) and internal rate of return (IRR) [40]. These techniques are briefly described as follows:

#### 1) PAYBACK METHOD

The payback method is used to calculate the time to return the original investment. The advantage of this method is its ease of use. The disadvantages are twofold, first, the time value of money is ignored, and second, the cash flow pattern which can lead to conflicting results, for example, in the scenario of positive cash flows appearing only in the very later years of the project. However, the payback period is a measure of risk with the method suitable for projects requiring small investments such as battery storage at the distribution level.

#### 2) ROA

This method (also known as return on investment) is used to calculate the average rate of return. This method does not consider the time value of money and as the average cash flow is used, the sequence of payback is immaterial to the calculation, but this factor is important for thorough financial analysis. The ROA is calculated using Equation (24).

$$ROA = \left(\sum_{t=0}^{n} \frac{Cash\,flow_t}{N}\right) \div I_0 \tag{24}$$

$I_0 =$ initial capital outlay
$n =$ life of the project

#### 3) NPV

This method considers the time value of money by determining the present-day value of expected future cash flows by discounting them at the cost of capital. For project acceptance the NPV should be at least zero and preferably positive. The NPV is calculated using Equation (25).

$$NPV = \sum_{t=1}^{n} \frac{Cash\,flow_t}{(1+k)^t} - I_0 \tag{25}$$

$k =$ cost of capital

#### 4) IRR

This method determines the interest rate, which is equal to the present value of the future cash flows. For project acceptance using this method, the IRR of a project must be greater than the opportunity cost of capital. The IRR is calculated using Equation (26).

$$\sum_{t=1}^{n} \frac{Cash\,flow_t}{(1+IRR)^t} - I_0 = 0 \tag{26}$$

## III. RESULTS

In this section the results of the modelling using the methodology outlined in Section II are presented. The DS3, DED, and UCM modelling were carried out using MATLAB. Frequency response modelling was carried out using the DIgSILENT PowerFactory. The FLEX and financial analysis modelling were carried out using Excel.

### A. SYSTEM SERVICES

Embedded generation at the distribution level in the form of an aggregation totalling 20 MW, made up of 200 individual 100 kW/400 kWh battery is used to model the revenue generated by selected DS3 products for the Irish power system in 2020. The formulation for the revenues of individual products follows a similar trend where the product of available volume, payment rate, scaling factor and duration make up the relevant payment as shown in equation (27). Payment rates use the latest published data [41]. A battery availability of 100% was assumed for this study. The consistent nature of the payments means that a percentage loss of availability equates to a pro rata loss in revenue except in the scenario where unavailability coincides with a high SNSP period in which

case the opportunity for the enhanced payments is lost. The modular nature of battery construction allows a partial swap out of cells with minimal effect on capacity. Additionally, the almost exclusive solid-state nature of battery systems keeps maintenance work at a low level.

$$DS3\ payment = available\ volume \times payment\ rate$$
$$\times scaling\ factor \times trading\ period\ duration$$
(27)

The scaling factor for each DS3 product is the multiple of individual factors pertinent to the product. The scalar values used in the modelling, and the DS3 revenues for 20 MW of aggregated battery storage using SNSP data for the Irish power system in 2020 using current rates are presented in Table 3 [33].

**TABLE 3.** Revenue from DS3 ancillary services for 20MW of aggregated storage using real time SNSP data.

| | | FFR | POR | SOR | TOR1 | TOR2 | RR$_{sync}$ |
|---|---|---|---|---|---|---|---|
| | Available volume | 20MW | 20MW | 20MW | 20MW | 20MW | 20MW |
| | Payment rate £/MWh | 1.97 | 2.95 | 1.78 | 1.41 | 1.13 | 0.23 |
| | Connection to grid | yes | yes | yes | yes | yes | yes |
| Scalars | Performance | 1 | 1 | 1 | 1 | 1 | 1 |
| | Product | 1 | 1 | 0.75 | 0.75 | n/a | n/a |
| | Continuous | 1.5 | n/a | n/a | n/a | n/a | n/a |
| | Fast response | 3 | n/a | n/a | n/a | n/a | n/a |
| | Locational | 1 | 1 | 1 | 1 | 1 | 1 |
| | Temporal | as SNSP | as SNSP | as SNSP | as SNSP | as SNSP | as SNSP |
| | Annual revenue | £1,715k | £913.6k | £413.4k | £327.5k | £349.9k | £71.23k |

This model shows the potential revenue which an aggregated total of 20 MW/80 MWh battery storage could earn by offering FFR, POR, SOR, TOR1, TOR2 and RR$_{sync}$ per annum totals £3,790,770. A check on the modelling technique was carried out by determining the number of quarter hour occurrences in 2020 for each SNSP range and calculating the revenue independent of the model for the POR payment. The results of this check are listed in Table 4. The total was compared to the POR payment of £20,035,884 made in 2020 by the system operators to eligible providers in the Irish market [43], [44]. The model revenue for 20 MW of POR services compared to the actual system operator amount seems high but it should be considered that the battery storage is always connected and therefore eligible for POR payments.

Dispatchable generators on the other hand will most likely be dispatched off during periods of high SNSP and thus would not be eligible for POR payments.

The FLEX product is being tendered by the DNO in Northern Ireland. The scheme is a pilot and is initially being offered to run for one year finishing on 30 September 2022. The products are mostly scheduled to run on weekdays from October

**TABLE 4.** Verification of POR payments for 2020.

| SNSP(%) | Scarcity scalar | No. of quarter hour occurrences | Revenue* |
|---|---|---|---|
| SNSP ≤ 60% | 1 | 28,060 | £413.9k |
| 60%<SNSP≤70% | 4.7 | 6,684 | £463.3k |
| SNSP > 70% | 6.3 | 392 | £36.4k |
| **Total** | n/a | **35,136** | **£913.6** |

*Revenue = MW × POR rate × scarcity scalar × no. of occurrences × 0.25

**TABLE 5.** Range of flex rates used to determine revenue.

| | Low | Mid | High |
|---|---|---|---|
| Availability £/MWh | £5 | £7.50 | £10 |
| Utilisation £/MWh | £100 | £150 | £200 |

**TABLE 6.** Revenue from flex network support services for 20MW of aggregated storage.

| Location | Product | Capacity MW | Availability (h) | Utilisation hours | Payment (low) | Payment (mid) | Payment (high) |
|---|---|---|---|---|---|---|---|
| 1 | Sustain | 0.6 | 0 | 504 | £30,240 | £45,360 | £60,480 |
| 2 | Sustain | 0.5 | 0 | 504 | £25,200 | £37,800 | £50,400 |
| 3 | Sustain | 0.6 | 0 | 504 | £30,240 | £45,360 | £60,480 |
| 4 | Sustain | 0.5 | 0 | 504 | £25,200 | £37,800 | £50,400 |
| 5 | Sustain | 0.5 | 0 | 504 | £25,200 | £37,800 | £50,400 |
| 6 | Secure | 1 | 2196 | 30 | £13,980 | £20,970 | £27,960 |
| 7 | Secure | 5 | 504 | 30 | £27,600 | £41,400 | £55,200 |
| 8 | Secure | 0.5 | 504 | 30 | £2,760 | £4,140 | £5,520 |
| 9 | Secure | 1.75 | 504 | 30 | £9,660 | £14,490 | £19,320 |
| 10 | Secure | 0.5 | 1512 | 30 | £5,280 | £7,920 | £10,560 |
| 11 | Secure | 0.5 | 1512 | 30 | £5,280 | £7,920 | £10,560 |
| 12 | Dynamic | 0.9 | 504 | 6 | £2,808 | £4,212 | £5,616 |
| 13 | Dynamic | 0.65 | 504 | 6 | £2,028 | £3,042 | £4,056 |
| 14 | Dynamic | 0.5 | 504 | 6 | £1,560 | £2,340 | £3,120 |
| 15 | Dynamic | 0.5 | 1008 | 6 | £2,820 | £4,230 | £5,640 |
| 16 | Dynamic | 5 | 1260 | 6 | £34,500 | £51,750 | £69,000 |
| 17 | Dynamic | 0.5 | 1512 | 6 | £4,080 | £6,120 | £8,160 |
| **Total** | | **20** | n/a | n/a | **£248,436** | **£372,654** | **£496,872** |

to March from 1600 h to 2000 h primarily to cover the peak load periods, with a total of 40.3 MW being procured. For this study, the annual revenue for each area was calculated for 20 MW of aggregated storage, made up of 200 individual 100 kW/400 kWh battery using the indicative availability and utilisation rates from the DNO documentation [34]. A storage level of 20 MW was chosen to be compatible with the frequency modelling. The availability and utilisation rates at the time of writing are not yet fixed so a low, mid, and upper set of rates are used for comparative analysis. The rates are listed in Table 5 and the results are presented in Table 6.

## B. FREQUENCY RESPONSE
The original power system model was modified with 163 MW of wind power generation. For this analysis, each wind

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**TABLE 7.** Scenario system parameters used for frequency response model with each scenario further subdivided into 4 cases.

| Scenario | Wind power (MW) | System demand (MW) | Synchronous generator power (MW) | System inertia (MW.s) | SNSP (%) |
|---|---|---|---|---|---|
| 1 | 0 | 259 | 279.4 | 1462.44 | 0 |
| 2 | 163 | 259 | 109.4 | 1259.25 | 63 |
| 3 | 163 | 219 | 69.4 | 760.75 | 75 |

turbine was set to 2 MW using the standard fully rated converter model available in the DIgSILENT library. The model is built in DIgSILENT PowerFactory, and further details on the DFIG modelling and software can be found in [45]. The wind farms are unequally distributed over the high voltage transmission side and the low voltage distribution part of the network. Two of the wind farms (of 50 MW each) are integrated into the high voltage level of 220 kV transmission voltage while the other two wind farms (32 x 1 MW and 31 x 1 MW, respectively) are connected to the lower voltage level 132 kV of the network. The SNSP is calculated using the Equation (28) [46]. The nadir in the modelling (approximately 49.8 Hz) is of a similar magnitude to that experienced in the Irish grid. This is verified by analysis of an event on the Irish grid on 9 August 2019 at 1841hrs where the loss of 186 MW generating load resulted in a frequency nadir of 49.64 Hz when the total system load was 4665 MW [21].

The scenarios used to evaluate system frequency stability under transient events are:

Scenario 1: Peak system demand (259 MW) with no wind power in the system.

Scenario 2: Peak system demand (259 MW) with wind providing 63% of the system demand, and therefore an SNSP level of 63%.

Scenario 3: System demand reduced by 15.5% with wind providing 75% of the system demand therefore an SNSP level of 75%.

A system disturbance of 25.9 MW increase in load is applied on Bus 14 at 0 s. Simulation results are recorded for 30 s. The system parameters for each scenarios are listed in Table 7.

$$SNSP\,(\%) = \frac{wind\ power\ generation(MW)}{total\ system\ demand\ (MW)} \times 100 \quad (28)$$

Battery energy storage was placed at different locations creating four cases for each scenario. The cases for each scenario were as follows:

Case 1: 20 MW BESS connected to Bus 01.

Case 2: 10 MW BESS connected to Bus 01 and a 10 MW BESS connected to Bus 13.

Case 3: 10 MW BESS connected to Bus 01, 5 MW BESS connected to Bus 13, and a 5 MW BESS connected to Bus 06.

Case 4: 5 MW BESS connected to Bus 01, 5 MW BESS to Bus 13, 5 MW BESS connected to Bus 06, and a 5 MW BESS connected to Bus 03.

### 1) BASE CASE SYSTEM PERFORMANCE WITH NO BATTERY ENERGY STORAGE

The base case models the system frequency and ROCOF response for 30 s following a 25.9 MW increase at Bus 14 at 0 s. The frequency response is shown in Figure 6 and the ROCOF response in Figure 7. A frequency below the Under Frequency Load Shedding (UFLS) limit will result in system load shedding. It should be noted that the UFLS in Ireland and Northern Ireland will be activated when the system frequency drops below 48.85 Hz [47].
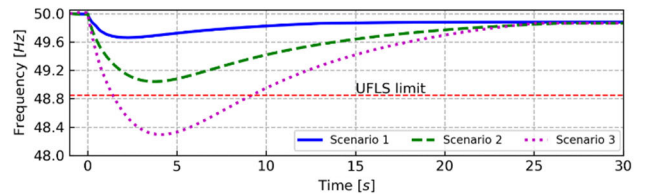


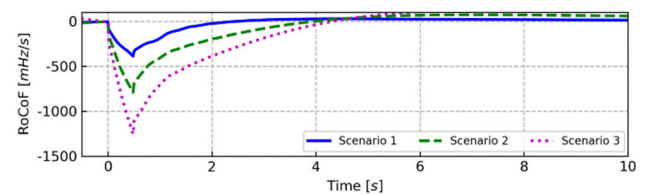**FIGURE 6.** Base case frequency response with no battery storage.



**FIGURE 7.** Base case ROCOF response with no battery storage.

The system frequency was recorded using a sampling time of 20 ms. The first derivative of these data was used to calculate the system ROCOF. It is worth noting that all ROCOF values are considered over a timeframe of 500 ms to be consistent with the current grid code regulations [48].

### 2) SCENARIO 1 WITH BATTERY ENERGY STORAGE

For the conditions described for Scenario 1, a disturbance equivalent to the base case is applied. The frequency and ROCOF responses for each case are shown in Figure 8 and Figure 9, respectively.
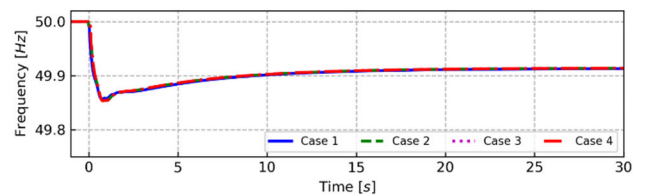


**FIGURE 8.** Scenario 1 (peak demand 259 MW and no wind) frequency response.

### 3) SCENARIO 2 WITH BATTERY ENERGY STORAGE

For the conditions described for Scenario 2, a disturbance equivalent to the base case was applied. The frequency and ROCOF responses for each case are shown in Figure 10 and Figure 11, respectively.
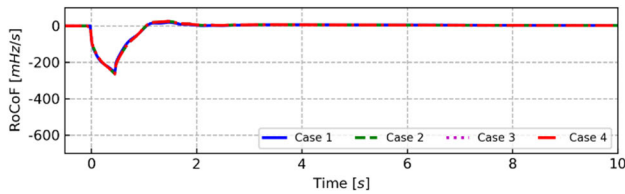
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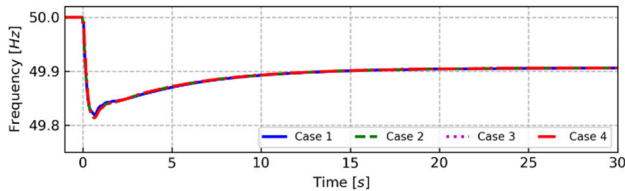**FIGURE 9.** Scenario 1 (peak demand 259 MW and no wind) ROCOF response.



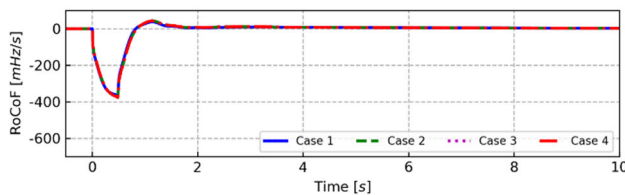**FIGURE 10.** Scenario 2 (peak demand 259 MW with wind at 163 MW) frequency response.



**FIGURE 11.** Scenario 2 (peak demand 259 MW with wind at 163 MW) ROCOF response.
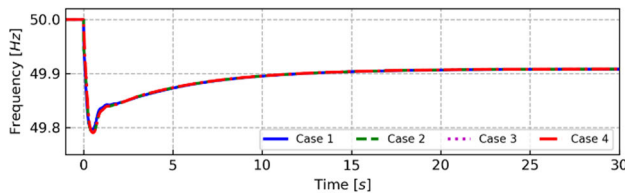


**FIGURE 12.** Scenario 3 (peak demand 219 MW with wind at 163 MW) frequency response.
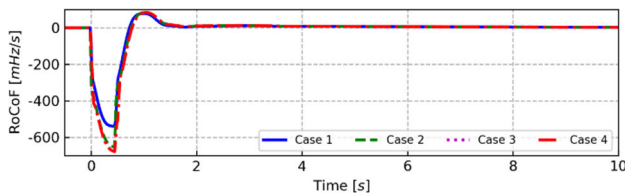


**FIGURE 13.** Scenario 3 ROCOF response (peak demand 219 MW with wind at 163 MW).

#### 4) SCENARIO 3 WITH BATTERY ENERGY STORAGE

For the conditions described for Scenario 3, a disturbance equivalent to the base case was applied. The frequency and ROCOF responses for each case are shown in Figure 12 and Figure 13, respectively.

### C. DED/MINIMISATION OF FUEL COSTS

In this section a comparison of production cost and emissions is made using a DED model with and without an aggregated total of 20 MW/80 MWh of storage. The profiles of
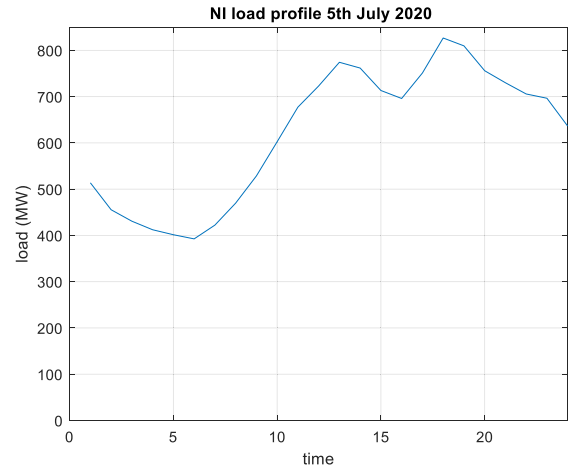


**FIGURE 14.** Load profile used in the dynamic economic dispatch model.

**TABLE 8.** Generator parameters used in dynamic economic dispatch model.

|  | a | b | c | d | e | f | $P_{min}$ | $P_{max}$ | RU | RD |
|---|---|---|---|---|---|---|---|---|---|---|
| $G_1$ | 0.12 | 14.8 | 89 | 3 | -2 | 7 | 90 | 260 | 300 | 300 |
| $G_2$ | 0.17 | 16.57 | 83 | 2.3 | -4.24 | 6.09 | 100 | 247 | 660 | 660 |
| $G_3$ | 0.15 | 15.55 | 100 | 1.1 | -2.15 | 5.69 | 100 | 247 | 660 | 660 |
| $G_4$ | 0.19 | 16.21 | 70 | 1.1 | -3.99 | 6.2 | 100 | 404 | 1320 | 1320 |

**TABLE 9.** Battery storage parameters used in dynamic economic dispatch model.

| Parameter | Value |
|---|---|
| $SOC_0$ (MWh) | 10 |
| $SOC_{max}$ (MWh) | 80 |
| $P_{max}^d$ (MW) | 20 |
| $P_{min}^d$ (MW) | 0 |
| $P_{max}^c$ (MW) | 20 |
| $P_{min}^c$ (MW) | 0 |
| $\mu_c^*$ | 95% |
| $\mu_d^*$ | 90% |

$^*\eta_c, \eta_d$     Charge and discharge efficiencies (%)

the thermal generators were sized to approximately replicate those used in the NI system. The load profile for NI from the SONI dataset for 5 July 2020 is shown in Figure 14 [21]. The generator parameters and battery parameters are listed in Table 8 and Table 9, respectively.

#### 1) DED WITH NO BATTERY STORAGE

The load profile generator schedule using the DED model with no battery storage is shown in Figure 15. The total cost and emissions per day for this scenario were £614,610 and 5,180 tonnes, respectively. In this scenario the total emissions include $CO_2$, NOx and SOx. The objective function is to minimise the costs for all generators dispatched on. Therefore, for a period during low loads, G2, G3 and G4 are at minimum generation. In addition, the system is operated without

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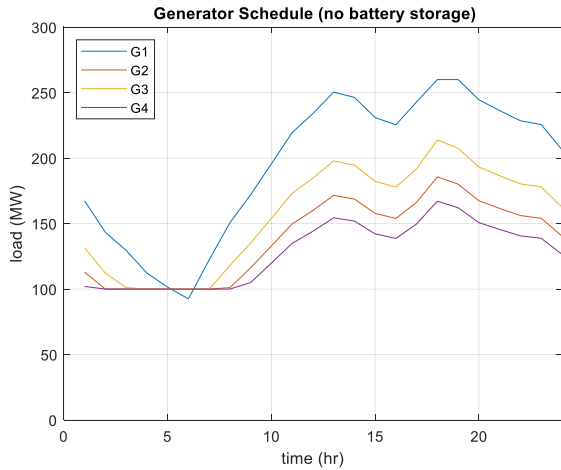


**FIGURE 15.** Generator schedule with no battery storage using dynamic economic dispatch model for NI load on 5th July 2020.

reserve. The cost determined in the model was verified as follows. The actual energy on 5 July 2020 was calculated as 14,312 MWh. The published average price/MWh for Q3 2020 was €53.68/£48.58, therefore, the average daily generation cost based on these actual figures is £695,277 which is in the same range as the results from the modelling [50].

### 2) DED WITH BATTERY STORAGE

The load profile generator schedule using the DED model with battery storage is shown in Figure 16. The battery charge/discharge profile is shown in Figure 17 with positive MW values indicating battery charging and negative MW values discharging. The total cost and emissions for the scenario with battery storage are £612,910 and 5,182 tonnes, respectively. The emissions intensity rates for the scenarios with and without battery storage are shown in Figure 18. This indicates a flattening of the intensity rate with the peak emissions lowered when battery storage is discharging, but with a corresponding rate increase when the battery is charging.
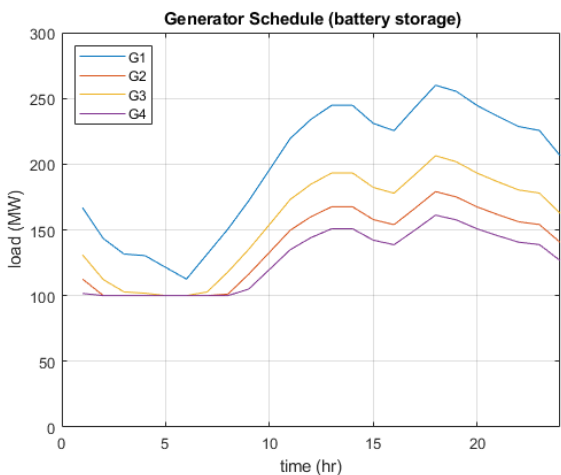


**FIGURE 16.** Generator schedule with battery storage using dynamic economic dispatch model for NI load on 5th July 2020.
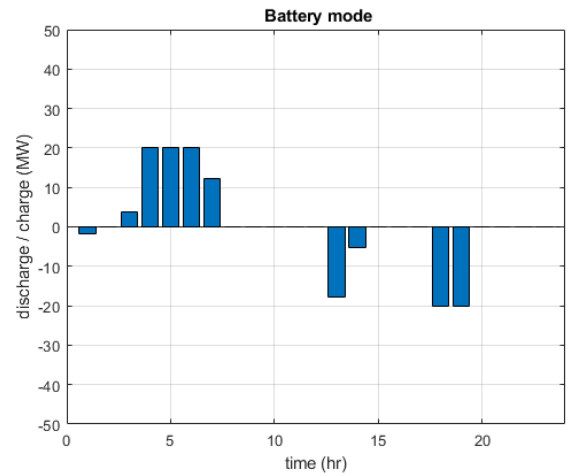


**FIGURE 17.** Battery charge/discharge profile using dynamic economic dispatch model for NI load on 5th July 2020.
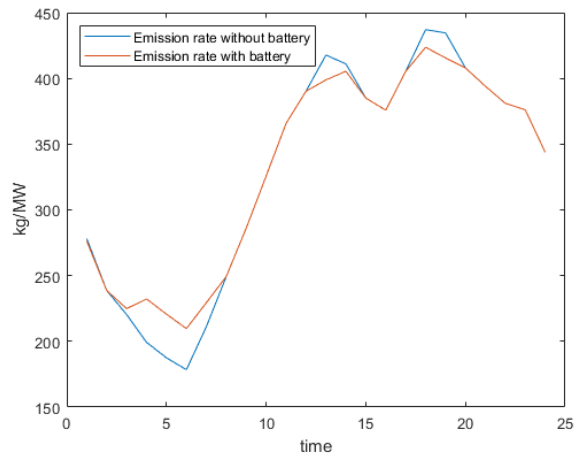


**FIGURE 18.** Emissions intensity rate with and without battery storage using dynamic economic dispatch model for NI load on 5th July 2020.

The results show a daily saving of £1,700 and an emission increase of 2 tonnes by using battery storage. From figures 15 and 16, for all four generators, the evening peak generation was reduced for the scenario with storage due to the battery discharging during this period. During the hours between 0200 h and 0800 h generator G1 generation was higher due to battery charging. The reduction of peak power has an additional benefit to power generation equipment especially CCGT plants, where running at higher loads shortens the maintenance interval times. As a test the model was run using 40 MW of battery storage, which resulted in savings of £3,040 and 6 tonnes against the no storage scenario. The results for 0 MW, 20 MW and 40 MW of battery storage are summarised in Table 10.

### 3) VALIDATION OF GENERATOR AND EMISSION COEFFICIENTS

The generation and emission coefficients were based on figures from [37] as it was not possible to extract these data in this form from publicly available datasets. To validate these

**TABLE 10.** Dynamic economic dispatch comparison of cost and emissions for 0 MW, 20 MW and 40 MW of storage.

| Scenario | Cost of dispatch per day | Total daily emissions | |
|---|---|---|---|
| 0 MW | £614,610 | 5,180 tonnes | |
| 20 MW | £612,910 | 5,182 tonnes | |
| 40 MW | £611,570 | 5,174 tonnes | |

**TABLE 11.** Validation of generator coefficients based on reference data.

| a | b | c | d | e | f | Fuel £/h at 200MW $aP^2+bP+c$ | Fuel £/h at 200MW SEM data (£50/MWh) | Emissions kg/h at 200MW $dP^2+eP+f$ | Emission kg/h at 200MW (490kg $CO_2$/MWh) |
|---|---|---|---|---|---|---|---|---|---|
| 0.17 | 16.57 | 83 | 2.3 | -4.24 | 6.09 | £10,197 /h | £10,000 /h | 91,158 kg/h | 98,000 kg/h |

coefficients, reference data were used as follows: gas fired power generation £50/MWh [51], emission rate 0.490 tonnes $CO_2e$/MWh [52]. Table 11 shows the comparison using the G2 CCGT coefficients used in the DED. The fuel costs and emission levels using the generator coefficients exhibit reasonable correlation with the figures obtained from published websites.

## D. UCM CURTAILMENT/RESERVE

In this section a unit commitment model is used to illustrate the cost of reserve. This model had ten units. The profiles of the thermal generators were sized to approximately replicate those used in both the NI and ROI systems. The load profile used was the same as that used previously. The salient generator parameters are presented in Table 12. To illustrate the cost of carrying reserve, a figure of 40% of the demand was chosen. The daily cost of operating the system without reserve is £535,030 whereas the cost of operating the system with reserve is £540,350. These costs are in line with the verification outlined in Part C.1 of this section. This demonstrates the additional cost of carrying reserve which is typically provided by partially loading synchronous generators which accounts for the additional cost. If this reserve can be otherwise sourced, for example, from battery energy storage, there is a potential saving. Reserves in the form of thermal synchronous generation are often dispatched in systems with a high share of renewables to cover events such as a rapid drop in windspeed. Curtailment of renewables can occur where system operation rules, such as an SNSP limit, force system operators to limit the output of renewables. Battery energy storage can be used to alleviate the amount of reserve carried by thermal synchronous generators and lower system curtailment of renewables. Synchronized replacement reserve is an ancillary service and is part of the DS3 package.

## E. FINANCIAL ANALYSIS

The potential sources of revenue for a battery connected to the NI system are from the ancillary services DS3 scheme, and the DNO network support FLEX scheme. If battery

**TABLE 12.** Generator parameters used in unit commitment model.

| | a | b | c | RU (MW/h) | RD (MW/h) | | $P_{min}$ (MW) | $P_{max}$ (MW) |
|---|---|---|---|---|---|---|---|---|
| $G_1$ | 0.148 | 12.1 | 82 | 40 | 40 | | 80 | 200 |
| $G_2$ | 0.289 | 12.6 | 49 | 64 | 64 | | 120 | 320 |
| $G_3$ | 0.135 | 13.2 | 100 | 30 | 30 | | 50 | 150 |
| $G_4$ | 0.127 | 13.9 | 105 | 104 | 104 | | 250 | 520 |
| $G_5$ | 0.261 | 13.5 | 72 | 56 | 56 | | 80 | 280 |
| $G_6$ | 0.212 | 15.4 | 29 | 30 | 30 | | 50 | 150 |
| $G_7$ | 0.382 | 14 | 32 | 24 | 24 | | 30 | 120 |
| $G_8$ | 0.393 | 13.5 | 40 | 22 | 22 | | 30 | 110 |
| $G_9$ | 0.396 | 15 | 25 | 16 | 16 | | 20 | 80 |
| $G_{10}$ | 0.51 | 14.3 | 15 | 12 | 12 | | 20 | 60 |

storage connected to the system is utilised by the transmission system operator as described, then cost savings, emissions reduction and reserve provision are realised. However, these services are not directly remunerated to the battery services providers. The total annual revenue from DS3 for battery storage of 20 MW/80 MWh in 2020 is £3,790,770. The total annual revenue from FLEX assuming the mid payment rate is £372,654. For a 100 kW/400 kWh battery the annual payment is £18,954 and £1,863 for DS3 and FLEX, respectively. For each of the financial analysis techniques, for assessment purposes, investment assumptions range from £100k-£175k. The installation costs of battery storage depend on the chosen technology. The modelling in this study determines the potential revenue for a 100 kW/400 kWh battery. Financial analysis was then used to determine the feasible investment level.

### 1) PAYBACK METHOD

The payback method is used to calculate the number of years to recover the capital outlay. Future payments were inflated at a rate of 1% per annum. This figure can be altered in the model to match the government predictions as time elapses [53]. The results are presented in Table 13.

**TABLE 13.** Simple payback in years for £100k-£175k investment.

| Capital investment | £100,000 | £125,000 | £150,000 | £175,000 |
|---|---|---|---|---|
| Payback (years) | 4.8 | 6 | 7.2 | 8.4 |

### 2) RETURN ON ASSETS

The ROA method is used to calculate the average rate of return by averaging the future payments over the project life cycle (10 years) and dividing by the initial investment. Future payments were inflated at a rate of 1% per annum. The results are presented in Table 14.

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**TABLE 14.** Return on assets for £100k-£175k investment.

| Capital investment | £100,000 | £125,000 | £150,000 | £175,000 |
|---|---|---|---|---|
| Return on investment (%) | 21.78% | 17.42% | 14.52% | 12.45% |

### 3) NET PRESENT VALUE

The NPV method is used to calculate the present value of future returns minus the initial investment over the project life cycle (10 years). Future payments were inflated at a rate of 1% per annum. Based on a 2018 report on the cost of capital for storage technologies, the discount rate used for the NPV calculation is 7.3% [54]. The results are presented in Table 15.

**TABLE 15.** Net present value for £100k-£175k investment.

| Capital investment | £100,000 | £125,000 | £150,000 | £175,000 |
|---|---|---|---|---|
| NPV(£) at 7.3% discount rate | £46,603 | £23,303 | £4 | -£23,295 |

### 4) INTERNAL RATE OF RETURN

The IRR method is used to calculate the interest rate which results in the future payments over the project lifecycle equating to the initial investment. Future payments were inflated at a rate of 1% per annum. The results are presented in Table 16.

**TABLE 16.** Internal rate of return for £100k-£175k investment.

| Capital investment | £100,000 | £125,000 | £150,000 | £175,000 |
|---|---|---|---|---|
| IRR % | 17% | 11% | 7% | 4% |

## IV. DISCUSSION

When DS3 was originally launched the bulk of the services was provided by the incumbent fossil fuel generators. The intention of DS3 was to provide the additional system services required to maintain grid security when operating with a high proportion of inflexible variable renewables, which for the island of Ireland was primarily wind generation. The current overarching NI governmental approach is to replace fossil fuel generation with indigenous renewables for a 70% renewable target by 2030 [56]. The UK government plans to phase out coal fired power stations by 2024 [57]. In the ROI the system operator Eirgrid has warned of an energy shortfall by 2025 which may require operation of their single coal fired station up to this date [58]. However, the closure of fossil fuel plants globally may be delayed due to the decision made at the Glasgow COP26 where countries like China and India have opted out of the agreement to "phase out" coal fired power stations [59]. However, continued use of fossil fuelled generation for DS3 services does not fit with the policy of replacing this type of generation with renewables. Energy storage in the form of batteries coupled with low carbon quick start generation is clearly a more environmentally friendly method to facilitate the continued development of renewable generation. In addition, the use of energy storage for load following, frequency regulation, and fast response negates the emissions which occur due to the ramping and

frequency response of fossil fuel generators. Battery storage provides FFR, POR, SOR and TOR by responding to system frequency. To deliver $RR_{sync}$ on demand, a battery storage control system requires a signal from the system operator. The DS3 scheme is designed to attract investment in technologies which will enable the system to operate at up to 75% SNSP. The regulation of the scheme is in the form of a monetary cap which up to 2021 has not been breached. An explanation of the current position and the expenditure limit of €235m per year is outlined in [42]. This note suggests that if current planned projects materialise, the limit may be breached. The current system is due for review in April 2023. Post April 2023 there is a possibility that DS3 payment rates may decrease to ensure that the current provision is maintained without exceeding the expenditure cap. This illustrates the corporate cannibalistic nature of the DS3 scheme and is a considerable risk for investors seeking a return over a reasonable time frame (10 years or more). However, as technology and market schemes rapidly evolve as governments strive to combat climate change, this volatile scenario is likely to prevail. As current operating conditions change, flexible services schemes such as DS3 must evolve to attract and retain providers and maintain the transition from fossil fuelled to low carbon electricity generation. These changes could be an increase in the expenditure cap or a restructuring of the scheme to incorporate the anticipated SNSP profile.

The FLEX product revenue for the aggregated 20 MW/80 MWh battery storage returned a comparatively lower revenue than the DS3 scheme at the same level of storage. The ideal scenario would be where battery energy storage at the distribution level, simultaneously delivered both FLEX and DS3 services. In doing so the technology would contribute to increased network flexibility at the distribution level in the form of network build out avoidance, voltage support, and alleviation of network congestion. Additionally, the stacked DS3 services will allow a higher share of renewable generation at the transmission level.

Frequency modelling demonstrates the positive effect of battery storage on the frequency nadir and ROCOF in a system with a high share of intermittent renewables and low inertia. Globally electricity systems are rapidly being transformed with the addition of renewables and the retirement of high inertia fossil fuel plants due to stringent environmental targets. Environmental reform is outpacing technological solutions to electricity system issues caused by renewable generation hence, it is important to develop battery storage to complement further development. In this section the frequency response of a system subjected to a load disturbance of 25.9 MW was modelled for four different placements (cases 1,2 3 and 4) of battery storage which totalled 20 MW using three scenarios plus a base case. Although the system modelled is small compared to the NI system, the purpose of this part of the study was to firstly determine the effect on frequency and ROCOF, and secondly to investigate the effect of placement location. The base case results displayed in Figures 6 and 7 show that the system nadir only breaches

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the UFLS limit for scenario 3 when the SNSP is 75% and inertia is lowest. Likewise, the highest ROCOF is for scenario 3 peaking at 1254 mHz/s. Note that the ROCOF limit for both NI and ROI is 1000 mHz/s [4]. The model is then tested with battery storage at various placements and combinations (cases 1 to 4) for the three scenarios. A summary of the frequency performance is presented in Table 17. These results suggest that the placement location of battery storage has little effect on the level of frequency nadir. However, the frequency nadir for the scenarios with storage is higher than that of the base case and for no occurrence, breaches the UFLS limit.

**TABLE 17.** Frequency nadir following 25.9 MW disturbance for all scenarios and cases.

| | Frequency nadir (Hz) | | |
| --- | --- | --- | --- |
| | Scenario 1 | Scenario 2 | Scenario 3 |
| **Base (without storage)** | 49.66 | 49.04 | 48.29* |
| **Case 1 (with storage)** | 49.86 | 49.82 | 49.80 |
| **Case 2 (with storage)** | 49.85 | 49.81 | 49.79 |
| **Case 3 (with storage)** | 49.85 | 49.81 | 49.79 |
| **Case 4 (with storage)** | 49.85 | 49.81 | 49.79 |

*UFLS limit breached

A summary of the ROCOF performance is presented in Table 18. These results suggest that the placement of battery storage influences the ROCOF. In scenario 1 (no wind power) there was a similar improvement in the ROCOF for all cases of battery placement. In scenario 2 (63% wind) the ROCOF was similar for each case with the best improvement coming from case 1, where a single battery of 20 MW was connected. Scenario 3 (load reduction and 75% wind) displayed a similar pattern to scenario 2 but with a higher overall ROCOF. The lowest ROCOF was for scenario 1, suggesting that in areas of high renewables and relatively low inertia, a single battery connection is more effective than a distributed connection. However, in terms of network build out avoidance and local peak supply constraints there is an argument for smaller and more distributed battery connections. This study is limited in that the impact of vector shift in the voltage waveform during rapid changes in system conditions on the ROCOF has not been considered [49]. Vector shift can impact the ROCOF calculation and is dependent on the location. In addition, ROCOF can vary between locations on the network. This is an area where further studies and analyses are required.

**TABLE 18.** Maximum ROCOF following 50 MW disturbance for all scenarios and cases.

| | Maximum ROCOF (mHz/s) | | |
| --- | --- | --- | --- |
| | Scenario 1 | Scenario 2 | Scenario 3 |
| **Base (without storage)** | -388 | -789 | -1254 |
| **Case 1 (with storage)** | -257 | -366 | -539 |
| **Case 2 (with storage)** | -264 | -377 | -654 |
| **Case 3 (with storage)** | -263 | -376 | -679 |
| **Case 4 (with storage)** | -266 | -380 | -685 |

Dynamic economic dispatch modelling examines the system with and without battery storage at 20 MW for a specific day in July 2020 for the Northern Ireland system. The inclusion of battery storage shows a saving of £1.7k with an increase in emissions of 2 tonnes. The emissions increase is due to (a) the dominance of the coal fired generator which has the highest emission rate and (b) the use of this machine for charging. The coal fired generator has the lowest cost coefficients therefore the dispatch of this machine is favoured by the optimisation model. This increase in emissions is further explained by the dispatch model used, where the objective function is based on minimising costs rather than emissions. This situation will prevail where countries continue to use coal fired generation. The use of coal for generation has recently been exacerbated by the rise in gas prices however this should only be a transitory effect [60]. For this research the use of coal generation in the modelling is justified by the recent decision of COP26 where it was agreed that countries like China and India will continue to utilise coal for generation. Regardless of the fossil fuel/renewable mix, battery storage has effectively introduced a buffer where energy can be deposited or withdrawn according to the system requirements. This is analogous to a hydraulic system accumulator which compensates for system disturbances caused by normal plant operation. A hidden benefit of this storage is increased duration running at steady state, which for rotating equipment ultimately results in less maintenance and down time. The modelling approach to dynamic economic dispatch is analogous to the research carried out in [61], where dynamic programming is used to solve a residential micro-cogeneration system which includes a fuel cell as the primary energy source, battery and thermal storage, and a heat pump. In the micro-cogeneration paper, the battery model SOC constraint uses voltage and current, whereas this study bases the SOC state on charge and discharge efficiencies. Another difference is that there are no ramping constraints in the micro-cogeneration paper. The use of thermal storage is beneficial, especially in areas of high renewable generation where surplus energy can be stored in this way in addition to battery storage. Another major difference between the two approaches is the use of a heat pump. This is particularly significant for NI, where the main energy source for residential heating is the use of domestic gas and kerosene boilers. The replacement of these boilers with heat pumps supplied by renewable generation significantly lowers the $CO_2$ emissions.

A unit commitment model was used to calculate the cost of carrying spinning reserve. Using the same load profile as the previous model, the daily cost of 40% reserve is £5,320. System operators have rules regarding levels of reserve which are dependent on factors such as SNSP and the capacity of the highest infeed. For this study a figure of 40% was chosen to obtain a sense of the cost of reserve provision. If connected battery storage can provide this spinning reserve, then savings can be realised by operating fossil fuel machines at the optimum level in terms of efficiency.

Four investment appraisal techniques (payback, ROA, NPV and IRR) were tested for a 100 kW/400 kWh battery installed at the distribution level in NI, participating in the DS3 and FLEX schemes. For the appraisals, the project life-cycle is set at 10 years. Using the simple payback method, an investment of £100k would return the capital outlay in about 4.8 years. However, this method does not take into consideration the future value of revenue and is totally reliant on a guaranteed revenue of DS3 and FLEX payments. The DS3 scheme is due for review in 2023 [42] and the FLEX scheme is a pilot scheme, currently due to run to from October 2021 – September 2022.

The ROA method results in a percentage return ranging from 22-12 % based on an investment of £100-175k. Like payback, this method does not consider the time value of money plus there is the additional uncertainty of future payments due to scheme reform. An investment decision would not be based on payback and ROA alone, but these techniques are important for small projects like battery storage at the distribution level as a ''go/no go'' indicator for further advanced financial analysis. For this reason, payback and ROA were included in this study.

The NPV and IRR techniques provide data for a more thorough appraisal process, as future costs are discounted at the cost of capital. Based on the projected returns from DS3 and FLEX, investments from £100k to £150k return a positive NPV at a discount rate of 7.3%. The IRR for a £100k investment was 17%. This would need to be competitive against other projects to attract investment. Battery installation costs currently range from £150-300 per kWh [8], [55]. Based on the median of this range an investment of £90k may cover installation costs for a 100 kW/400 kWh battery. However, a more advanced analysis would be necessary to consider full lifetime costs, risk of revenue continuity, performance degradation and scrappage costs.

The financial and environmental benefits of incorporating battery storage into a power system have been demonstrated by the DED and UCM modelling. The use of energy storage has been recognized by electricity system operators, particularly those operating systems with a high share of renewables. The financial modelling shows some promising results caveated by the uncertainty of payments from schemes such as DS3 and FLEX. The gap which exists is to match market and commercial arrangements, to set a scenario where fair returns are guaranteed for investors in battery storage at the distribution level in return for enhanced system operation, in terms of increased levels of renewables and growth in electrification.

## V. CONCLUSION

This analysis uses market modelling to test the market feasibility of investment in battery storage at the distribution level. On the revenue side, storage was modelled using a frequency dataset for Ireland for 2020, to calculate payments for services associated with the DS3 and FLEX schemes. Actual revenue values were used for DS3, and a range of values for FLEX. System performance in terms of frequency, ROCOF, cost, emission reduction, and reserve were modelled using dynamic economic dispatch and unit commitment models. Financial analysis used the results of the revenue models to test investment feasibility propositions using payback, return on assets, net present value, and internal rate of return techniques.

The analysis showed that energy storage in a system with a high share of renewables is beneficial in terms of lowering costs and emissions. The storage effectively created a repository for surplus renewable energy to be stored during periods of low demand and then used later at peak times. The cost of carrying system reserve can be lowered when a system carries energy storage by reducing ramp rates, avoiding uneconomic peak load running, and the use of expensive peaking plant. The reserve model was tested at 40% of demand to align with the region being studied. Testing at different levels of reserve is possible and could form the basis for future work.

The frequency and ROCOF response were tested by subjecting a system with and without energy storage to a disturbance of 25.9 MW. Battery storage has a positive effect on reducing the frequency nadir regardless of the placement location. However, the reduction of ROCOF for systems with a high share of renewables is dependent on the battery storage location. The results indicated that for similar ratings, a single battery was more effective in reducing the ROCOF rates than a widely distributed pattern.

On the revenue side the available monies from DS3 and FLEX when measured for a 100 kW/400 kWh at the distribution level against the capital investment required, showed fewer promising results. The main risk is the lack of guaranteed income plus the potential dilution of payments due to the cap imposed by the regulator on ancillary services payments. This effectively reduces the revenue as more players enter the market.

A summary of the key findings is listed as follows:

(a) Battery storage deployed in a system with high renewables will lower emissions and, generating and reserve costs.

(b) Battery storage will reduce the frequency nadir following a system loss of generation event.

(c) The lack of guaranteed ancillary services revenue plus potential dilution of payments introduces an unacceptable risk for investors in battery storage.

This investigation demonstrates how energy storage placed in a power system with a high level of renewables complements system operation and facilitates the maximum use of low carbon technologies. Recent developments at COP26 may prolong the use of coal fired generation but countries are still signing up to prohibit use of coal, albeit at a slower rate than what is required to meet climate change goals. However, financial reward mechanisms fall short of providing the return that investment in energy storage requires. This highlights the gap between revenue from operator incentive schemes for system services and the financial returns required for investment in suitable technology. Future studies will focus on using current unit commitment software packaged with

energy storage at the distribution level to support increased electrification and renewable generation.

## ACKNOWLEDGMENT

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**DLZAR AL KEZ** (Graduate Student Member, IEEE) received the B.Sc. degree in electrical engineering from the University of Sulaimani, Sulaymaniyah, Iraq, in 2009, and the M.Sc. degree (Hons.) in energy and sustainability with electrical power engineering from the University of Southampton, Southampton, U.K., in 2012. He is currently pursuing the Ph.D. degree with the Energy, Power, and Intelligent Control (EPIC) Research Cluster, Queen's University Belfast, U.K. He then joined the Department of Electrical Engineering, University of Sulaimani, in 2012, where he served as an Assistant Lecturer, until 2018. He worked for industries, and he was a Power Manager of the IQ Network Company, the largest fiber optic internet provider company in the Kurdistan Region, Iraq, from 2017 to 2018. His doctoral research investigates power systems dynamics with high wind generation penetration. He was a recipient of the Best Paper Award from Queen's University Belfast, in 2020.

**ROBERT BEST** (Member, IEEE) received the M.Eng. and Ph.D. degrees from Queen's University Belfast (QUB), in 2004 and 2008, respectively.

After his Ph.D. degree, he spent several years with QUB as a Research Fellow and was appointed as a Lecturer at the Energy, Power and Intelligent Control (EPIC) Research Cluster, QUB, in 2013. His research interests include distributed generation, energy storage, phasor measurement unit applications, and power systems operation with high renewable penetration.

**NEIL MCILWAINE** (Member, IEEE) received the B.Sc. degree in electrical and electronic engineering from Queen's University Belfast, U.K., in 1983, and the M.Sc. degree in manufacturing technology, design, and management from Ulster University, in 1993. He is currently pursuing the Ph.D. degree with the Energy, Power, and Intelligent Control (EPIC) Research Cluster, Queen's University Belfast.

He spent 35 years in the power generation industry specializing in control and instrumentation and operations and was the Maintenance Manager at a 620 MW power station. His doctoral research is a market analysis of customer connected mass energy storage.

Mr. McIlwaine is a member of the IET.

**XI LU** received the Ph.D. degree from the Harvard John A. Paulson School of Engineering and Applied Sciences, Harvard University, in 2010.

Since 2010, he continued working at Harvard as a Postdoctoral Fellow, a Research Associate, and a Lecturer until joining Tsinghua University, in 2015, where he is currently a tenured Associate Professor with the School of Environment. His research interests emphasize study of the technical, economic, and environmental dimensions of zero carbon energy sources in transitioning to a carbon neutral society. His primary research interests include modeling complex systems of renewable energy, environment and climate, integrative solution for large-scale deployment of wind and solar power, energy storage, emission inventory of GHGs and air pollutants, as well as carbon neutral urbanization energy systems. He has published papers in *Science*, *PNAS*, *Nature Energy*, *Joule*, *Nature Sustainability*, and *Nature Communications* on these topics.

Dr. Lu won the Chinese Government Award for Outstanding Self-Financed Students Abroad, in 2010, and received the National Science Fund for Excellent Young Scholars, in 2017, and the National Science Fund for Distinguished Young Scholars, in 2020.

**AOIFE M. FOLEY** (Senior Member, IEEE) received the B.E. degree in civil engineering and the Ph.D. degree in unit commitment modeling of wind and energy storage in the Irish power systems from University College Cork, Ireland, in 1996 and 2011, respectively, and the M.Sc. degree in transportation engineering from Trinity College Dublin, Ireland, in 1999.

She worked in industry for 12 years for ESB International, Siemens, SWS Energy, and PM Group, mostly in the planning, design, and project management of energy, telecoms, waste, and pharma projects. She is a Reader with the School of Mechanical and Aerospace Engineering, Queen's University Belfast, U.K. Her research interests include energy systems modeling focused on electricity systems, markets and services, wind power, electric vehicles, and smart technologies.

Dr. Foley is a Founding Member of the IEEE VTS U.K. and Ireland Chapter, in 2011, a Chartered Engineer, in 2001, a fellow of Engineers Ireland, in 2012, and a member of the IEEE PES and VTS. She is the Editor-in-Chief of *Renewable and Sustainable Energy Reviews*.

**CHONGYU ZHANG** received the B.E. degree in environmental engineering and the B.S. degree (dual bachelor's degree) in pure and applied mathematics from Tsinghua University, in 2018. He is currently pursuing the Ph.D. degree in environmental science and engineering with the School of Environment, Tsinghua University. His research interests include electric vehicle smart charging, wind power integration, and resource assessment of wind power.