Decarbonisation of Rural Networks Within Mainland Scotland: In Support of Intentional Islanding

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Abstract

This paper investigates the role of Battery Energy Storage Systems (BESS) in the decarbonisation of rural networks within mainland Scotland and considers the challenges with the transition to 100% renewable powered networks. In doing so particular attention is placed on the relationship with the wider network and this leads us to consider the use of intentional islanding as a mechanism for supporting distributed grid operation. Geographic Information System (GIS) data provided by Scottish Power Energy Networks is translated for use in power flow modelling software OpenDSS and this forms the basis for the studied MV and LV networks. The modelling approach includes simulating line capacity constraints upstream of the 33/11 kV primary transformer and then analysing the corresponding control response under a series of scenarios for two differing seasonal cases. The findings emphasise the importance of battery sizing and highlight the challenges involved in its use to displace back-up diesel generation but also to provide grid management services and facilitate intentional islanding decisions. The findings support the development of *carbon intensity* dynamic control as a metric to inform flexibility management decisions and control actions in rural areas for a system wide carbon benefit.

1 Introduction

The drive towards a net-zero society by 2045 is a key target for the Scottish Government's energy transition [1]. It is expected that with increased electrification of the heat and transport sectors that there will be a transition to 100% renewable powered networks [2]. Current rural networks in Scotland consist of sparsely located demand centres supplied by overhead lines (OHLs) that span challenging terrains and must endure adverse weather conditions. As consumer reliance on the electricity network increases security of supply concerns are amplified for distribution network operators (DNOs). Conventionally, DNOs are required to maintain security of supply through asset management and network reinforcement, making decisions based on a limited measurement set [3]. However, as distribution networks continue to evolve and as DNOs transition to Distribution System Operators (DSOs), there is a growing requirement for more flexible approaches to network management as opposed to the conventional 'fit and forget' [4] reinforcement methodology [5], [6]. The development of 'smart' technologies and an increasing ethos for a 'flexibility first' approach presents an opportunity to limit the need for network reinforcement [7]. This is echoed by Ofgem (the regulator for Great Britain (GB)) where they have emphasised that DNOs should be responding to the inherent flexibilities associated with low carbon technologies by exploiting flexible solutions across the next round of price controls (RIIO-ED2) [8].

One alternative method of network management is intentional islanding [9], which relates to when an area of network is intentionally disconnected from the grid supply and local assets such as generation and storage are used to independently

support a managed set of flexible demand [9]. Intentional islanding has numerous benefits, though, typically the primary function is to ensure security of supply in the event of an outage [10]. This indicates that a grid connected state of operation would be the primary operating state and intentional islanding would be used in a back-up capacity. As a result, this paper considers 'grid neutrality' which involves utilising the flexibilities of distributed assets in the primary operating state to reduce reliance on the grid supply, similar to 'virtual island mode' as demonstrated in Simris Sweden as part of the Interflex project [11], [12]. Primarily to exploit the renewable resource availability associated with rural networks and the increasing volume of distributed assets through the communication and control infrastructure required for intentional islanding whilst avoiding the disruption and expense associated with reinforcing the network at a higher voltage.

This paper investigates how a locally controlled BESS can be preferentially used to limit the use of back-up diesel generation and off-set the curtailment of renewable generation on a real Scottish rural network. The paper introduces the concept of carbon intensity (CI) dynamic carbon control guided by [13] for 'grid neutral' operation and its role in decarbonising rural networks by minimising grid interaction based on data provided by National Grid Electricity System Operator (NGESO).

The remainder of this paper is organised as follows. Section 2 provides a detailed description of the network model and the development of representative demand and generation profiles as well as the control modelling methodology for the battery storage. Section 3 describes three case studies that consider different approaches to controlling the BESS. Section 4

provides the results of these case studies and Section 5 presents conclusions and further work.

2 Model Development

2.1. Distribution Network

A portion of Scottish Power Energy Network's distribution network as represented by Fig. 1 (described in [14], [15]) forms the basis for this analysis. Each of the 857 network loads has a fixed power factor of 0.95 as per [16]. No information was provided in relation to individual phase connections therefore the network was assumed balanced. No information of microgeneration is available therefore solar PV has been stochastically distributed throughout the network.

The grid supply operating as a slack bus is connected to an OHL, which then supplies the downstream MV and LV networks (modelled from translated GIS data). The OHL line is sized based on the after diversity maximum demand (ADMD) [17] and then oversized as is typically the case when supplying rural networks. For modelling simplicity assets are connected to the same bus as the 11 kV side of the primary transformer to facilitate local network balancing in the event of an upstream constraint. Assets include a 1000 kVA hydro scheme connected via OHL and a back-up 250 kVA diesel generator connected locally. Battery storage when connected is also located at this bus aiming to mitigate the impact of asset location within the analysis. The storage is rated at 250 kW and 1000 kWh having a power factor of 1. Also, with a 98% charge/discharge efficiency [18] and fixed losses at 1% of the kW rating. It is sized relative to the back-up diesel generator to meet a similar severity of constraint at peak operating hours.

2.2. Demand and Generation Profiles

The demand profiles utilised in this study are generated from the CREST model [19] which provides diversified domestic profiles based on household occupancy at a 5-minute resolution. The CREST model is an established method for simulating consumer demand profiles and is based on the UK Time Use Survey (TUS) which is a large-scale survey documenting consumer household behaviour [20]. A unique demand profile is generated for each household by providing the model with: month, day (weekend or weekday), number of residents (1–4+) and household type (semi-detached, detached or terraced). By using GIS data of 2011 UK Census Output Areas (OAs) and the UK Ordnance survey building type dataset as per [14] the housing stock for the network is determined as is the probability of a specific number of residents per household (in this work the number of occupants attached to the highest probability is employed).

The PV generation profiles are also generated by the CREST model [19], though in this case separately so as not to influence individual household demand, allowing for the calculation of the net aggregate of both demand and generation independently. The model considers sun irradiance and cloud coverage to stochastically produce representative PV profiles. There are 3 PV array area sizes available: 7 m², 10 m², 13 m² and for a 20% PV distribution (171 households) the distribution is 66, 56, 49, respectively. It is assumed due to the close geographic nature of the households that dwellings with

Fig. 1. Network GIS data overlaid on OpenStreetMap via GeoPandas and Mplleaflet in Python.

PV share the same irradiance profile, with each PV system having a power factor of 1. Due to the nature of hydro generation minimal variance has been assumed over the span of the daily time horizon.

2.3. Control Modelling Methodology

To balance the network locally the aggregated demand and generation are required. This allows for the calculation of the imbalance and application of control actions to restore balance when necessary. The aggregated demand and generation are calculated at time $t = \Delta t$ as follows:

$$P_{\text{dem}} = \sum_{i=1}^n lp_i \text{ and } P_{\text{gen}} = \sum_{j=1}^m gp_j \quad (1)$$

where P_{dem} represents the aggregated demand at the 11 kV side of the primary transformer, lp_i is the measurement of the i^{th} consumer load profile at the t^{th} interval, and n is the number of connected loads. The term P_{gen} is calculated using the same approach by considering all connected generation, where gp_j is the measurement of the j^{th} generation profile at the t^{th} interval, and m is the number of connected generation.

The state of imbalance is calculated by identifying the power flow direction through the primary transformer i.e. by determining if the local network is importing, exporting or balanced, expressed as:

$$P_{\text{PF}} = P_{\text{dem}} - P_{\text{gen}} + P_{\text{losses}} \quad (2)$$

where P_{losses} relates to local network losses and P_{PF} represents the active power flowing through the primary transformer.

2.3.1. Battery Energy Storage System Model

As the battery's state of charge (SOC) varies with each charge/discharge cycle, a battery controller is developed to account for the energy availability and rated power capacity constraints guided by the approach used in [21]. The maximum energy capacity E_{max} equates to the rated energy capacity of the battery (100% SOC) in this case 1000 kWh. It is typical that lithium-ion batteries are not discharged fully to 0% holding a capacity margin of reserve, as a result, the minimum energy capacity E_{min} is set at 200 kWh (20% SOC). The charging power P_{ch} is calculated by using the expression:

$$P_{\text{ch}} = \begin{cases} 0, & a! \\ P_{\text{ch}}^x, & a \& b \& c! \\ P_{\text{avl}}, & a \& b \& c + a \& b! \& c \& d! \\ P_{\text{ch}}^{\text{max}}, & a \& b! \& c! + a \& b! \& c \& d \end{cases} \quad (3)$$

where $a = (x > P_{\text{PF}}) \& (E_{\text{max}} > E_t \geq E_{\text{min}})$, $b = P_{\text{ch}}^{\text{max}} \geq P_{\text{ch}}^x$, $c = E_{\text{ch}}^x \geq E_{\text{avl}}$, $d = P_{\text{avl}} > P_{\text{ch}}^{\text{max}}$, E_t is the energy held within the battery at a given time-interval $t = \Delta t$, x is the line capacity under constraint conditions (negative value when exporting, positive when importing) $P_{\text{ch}}^{\text{max}}$ is the maximum charging power, P_{ch}^x is the excess active power exceeding the constraint and E_{ch}^x is the energy equivalent, P_{avl} is the available charging power and E_{avl} is the energy equivalent. The discharging power P_{dch} is calculated by using a similar expression adjusting: x , conditional a and the calculation of P_{dch}^x and E_{avl} . A minimum charge of 3 kW is required to overcome losses and ensure that the battery when in 'charging mode' results in a positive change of energy. This change in energy is calculated as follows:

$$E_{\text{ch}} = (P_{\text{ch}} - P_{\text{loss}}^{\text{fixed}}) \times \Delta t \quad (4)$$

$$E_{\text{ch}}^{\text{loss}} = E_{\text{ch}} \times (1 - \eta_{\text{ch}}) \quad (5)$$

$$\% \Delta \text{SOC} = \left(\frac{E_{\text{ch}} - E_{\text{ch}}^{\text{loss}}}{E_{\text{max}}} \right) \times 100 \quad (6)$$

where E_{ch} is the energy charge increase in consideration of the fixed losses $P_{\text{loss}}^{\text{fixed}}$ taken as 1% of the kW rating, $E_{\text{ch}}^{\text{loss}}$ represents the energy loss associated with the charge efficiency η_{ch} and $\% \Delta \text{SOC}$ the SOC percentage change. Noting that a 3 kW minimum charge effectively sets an upper bound tolerance of 0.025% SOC where battery operation would automatically change to 'idling mode'.

When discharging, exceeding the minimum threshold is of concern in certain instances, therefore in order to prevent this, discharge losses have to be considered, this can result in a reduction of the active power discharged though remains a necessity for maintaining the deserved reserve. To avoid breaching the minimum threshold, discharging of the battery is adjusted to account for the minimum capacity limit. Hence:

$$E_{\text{avl}} = E_t - E_{\text{min}} = E_{\text{dch}} + ((E_{\text{dch}} \times (1 - \eta_{\text{dch}})) + E_{\text{loss}}^{\text{fixed}}) \quad (7)$$

where (7) can be re-arranged to calculate E_{dch} (based on E_{avl}) and subsequently P_{dch} in respect of the discharge losses. In extreme cases the 20% threshold could be reduced by adjusting E_{min} based on specific system conditions. However, this was outside the scope of the studies reported in this paper.

2.3.2. Curtailment Strategy

Curtailment in this model is based on a pro-rata methodology given the volume of PV installations. Residential disaggregated curtailment is extremely uncommon in current network practice though until a high volume of flexible distributed assets are introduced this could prove as a necessity with the continued penetration of high amounts of PV, specifically when considering islanded networks. As a result, the studies considered in this paper assume that all generation has a 'non-firm' connection agreement (where they are required to curtail as necessary).

3 Case Studies

3.1. Case 1 - Back-up Diesel Displacement with BESS

In this case, to simulate an environment where back-up diesel is required, the OHL connecting the hydro plant must be down for maintenance or through an outage in addition to the constraint upstream of the primary transformer. Four realistic though conventionally infrequent/atypical constraint scenarios are considered where only: 80%, 70%, 60% and 50% of the grid supply OHL capacity is available between a period of 17:00–22:00 on a mid-week winters day in February, (representative of a worst-case scenario). As the battery is introduced a fixed SOC of 100% is considered at the start of each constraint period. In practice the SOC would vary as: other grid services are utilised, in the event multiple constraints per-day occur and as intentional islanding is introduced. To fully incorporate a varying SOC the probabilities in terms of constraint magnitude and occurrence would have to be considered as would the magnitude and frequency of intentional islanding events.

3.2. Case 2 - Curtailment Reduction with BESS

This case seeks to demonstrate when there is an excess of generation and historically curtailment would be required to meet the constrained export capacity. Following a similar set-up to Case 1 in terms of the constraint scenarios. However, in this case the hydro plant would be connected and a period of low demand (04:00–09:00) on a mid-weekday in July is considered. A fixed SOC of 50% is considered at the start of the constraint period.

3.3. Case 3 - Dynamic Control for Grid Neutrality

This case aims to introduce the concept of CI dynamic carbon control where granular CI figures are used as a metric to determine optimal battery control actions that limit interaction with the grid to periods of increased renewable generation. NGESO calculates and records CI figures for GB and regional areas of GB every half hour, also providing a 2-day ahead half hourly forecast. Access to records has been provided by NGESO to facilitate this early/ongoing research directly through a callable Python script to their Application Programming Interface (API) [22].

Using a historic winter and summer daily CI record (actual and not a forecast) from February and July 2020 the dynamic control is introduced based on conditions outlined in NGESO's technical documentation [23] where they consider the CI measured in CO_2/kWh to be: Very High 360+, High 260–359, Moderate 160–259, Low 60–159 and Very Low 0–59. This creates bounds to which battery control can be configured, discharging when either Very High or High and charging when Moderate, Low and Very Low, respectively. The model is adjusted to meet the charge/discharge conditions, in this example demonstrating operation based on historic data though future work seeks to utilise the forecasts to plan and coordinate charging/discharging with other flexible assets. In this case the hydro plant is removed to represent how this technique would be applied to more typical areas of network.

4 Case Study Results

4.1. Case 1 – Diesel Generator Displacement

Fig. 2 highlights the conventional network operation where the back-up diesel is brought online to meet demand under a network constraint, indicating that as the available OHL capacity reduces, reliance on the diesel generator increases. As the grid operates as a slack bus, the 'Demand Unmet' indicates that with the reduced line capacity and the diesel operating at rated output the demand could not be met, in practice this would cause tripping of the relevant protection disconnecting consumers as the grid tries to supply more power than is feasibly possible under the constraint.

The size of the back-up diesel (or multiple back-ups) is analogous to the constraints commonly experienced on this part of the network, where the DNO would typically consider the risk, probability and severity, ensuring adequate back-up capacity to feasibly secure against the majority of probable constraints. As expected with a winter scenario the contribution of PV is minimal and fails to contribute during the constraint period. Fig. 3 introduces the battery storage to the network aiming to displace the reliance on diesel generation. Noticeably, the storage ensures in every scenario that the demand is met during the constraint period, although reliance on the diesel is still prevalent as the severity of the constraint increases. This is a consequence of how the storage is sized, to fully displace diesel and secure against 50% capacity constraints the battery's kW rating would have to be increased.

4.2. Case 2 – Curtailment Reduction

Fig. 4 demonstrates operation of the network when a constraint occurs that limits the export capacity. Indicating that curtailment of the hydro generation increases as available export capacity reduces. However, Fig. 4(c) and Fig. 4(d) indicate that should the constraint occur between 12:00 and 18:00, curtailment of PV would also be required. Due to the pro-rata methodology employed for only 20% PV penetration, as penetrations increase, further curtailment would be necessary under less severe (more probable) constraints.

Fig. 5 demonstrates network operation with the introduction of the storage under an export constraint. Highlighting that curtailment is reduced and the battery begins to charge.

Fig. 2. Back-up diesel operation without BESS for reduced OHL capacities of (a) 80% (b) 70% (c) 60% (d) 50%.

Fig. 3. Introduction of BESS to displace back-up diesel operating under reduced OHL capacities of (a) 80% (b) 70% (c) 60% (d) 50%.

However, in Fig. 5(d) as the initial SOC is 50% the battery charges fully within the constraint period and curtailment is required though less than without the battery. Hence sizing is again emphasised, indicating not only the importance of constraint size but also its duration, a similarly crucial aspect to sustained operation in island mode.

4.3. Case 3 – Dynamic Carbon Control

Fig. 6 shows that the daily CI trend for 2019 [22] follows that of demand in terms of peaks and indicates that CI predominately falls within 'Moderate' to 'Low' based on the category distribution outlined by NGESO. However, this figure also indicates the level of variance seen with a wide operating region per time interval. This variation is likely based on seasonal and inter-weekly variation (weekend trends vary compared with weekdays). Though this is also likely to fluctuate with variations in demand as seen by the transmission network.

This indicates that conventionally charging during low demand hours may not always be the most environmentally

Fig. 4. Generation curtailment without BESS for reduced OHL capacities of (a) 80% (b) 70% (c) 60% (d) 50%.

Fig. 5. Introduction of BESS to reduce curtailment operating under reduced OHL capacities of (a) 80% (b) 70% (c) 60% (d) 50%.

efficient time to charge. Fig. 7 highlights an example of CI dynamic control for a winter's day. As shown, the battery is charged and discharged based on the CI, it is noticeable when the battery becomes fully charged/discharged. When discharging, the power supplied from the grid is reduced close to zero and when charging, increased reliance is demonstrated (when the contribution from local PV is limited).

As the CI data is recorded at half hour intervals, the granularity of the 5-minute resolution is lost. However, with GB smart meter data recorded at half hourly intervals this level of granularity proves applicable, though literature such as [3] have raised concerns with dynamic control at a half hourly time interval, therefore future research would predominately utilise the 2 day ahead forecasts by NGESO for network flexibility planning. Fig. 8 highlights a summer's day example. As shown, the battery charges as intended. However, becomes fully charged and does not necessarily utilise the full potential of the grid supply when the CI is low.

Fig. 6. CI trend for half hourly time periods throughout 2019.

Fig. 7. CI dynamic control on a winter's day.

Fig. 8. CI dynamic control on a summer's day.

5 Discussion and Conclusions

The results presented identify issues surrounding the use of battery storage as a replacement for back-up diesel generation and the curtailment of generation in the drive towards 100% renewable powered networks. The importance of battery sizing is emphasised, specifically in terms of meeting varying levels of constraint severity for extended periods. The displacement of co-located diesel generation is dependent on the frequency, magnitude and length of constraints experienced. Purely in isolation, as shown, battery storage could be utilised for displacement of back-up diesel generation and for minimising curtailment if appropriately sized.

The difficulty is with the cost of BESS compared with back-up diesel generators and the evolving nature of the network. Hence maximising the storage value through the utilisation of additional services such as frequency response (an established GB market segment) and support for intentional islanding proves desirable. These services strengthen the business case for deploying not only BESS, but also intentional islanding. However, through these additional services further complexity

is introduced, e.g. as the SOC varies through more frequent use, in the event of an unanticipated constraint can the controller and battery storage guarantee sufficient response to meet the back-up requirements. This also applies to islanding operation and the capacity requirement for maintaining an islanded network. Additionally, with more frequent use in relation to the number of charge and discharge cycles, the lifespan of BESS must be taken into consideration. More frequent use does not always translate to a negative as in terms of back-up diesel generators often they can fail when required as they have sat idle for prolonged periods. Optimal network location is another key parameter that will vary depending on the services provided by the battery storage and may differ from the back-up diesel generator location.

In terms of curtailment, there is limited research into the most appropriate approach for curtailment of distributed micro-generation at a residential level. Primarily as this is likely to be minimal depending on penetration levels and energy storage capacity, though under a constraint scenario as shown a requirement may still exist in the near future until a suitable penetration of flexible assets exist to facilitate more flexible network management.

The concept of CI dynamic control of rural networks to facilitate ‘grid neutrality’ has been introduced. The results provide early insight into CI behaviour and the potential for flexibility planning through battery control. The results further emphasise the importance of battery sizing and also identify the potential for staggered charging during periods of Low CI. As more flexible assets connect to the network there is potential to fully maximise periods of Low CI and fuel the drive towards ‘grid neutral’ operation during times of High CI. Enhanced network visibility, disaggregated control of independent assets and a responsive communication network, due to upfront costs have historically been barriers to the implementation of intentional islanding at a residential level given the physical amount of time spent in islanding mode. Though with the addition of ‘grid neutrality’ a more justifiable business case can be made for the introduction of the communication and control infrastructure required. In terms of using national/regional CI figures and forecasts for network management, there is substantial further research and development required to fully ascertain the viability and feasibility of this technique.

Fundamentally, energy storage is expected to play a significant role in the decarbonisation of rural networks in Scotland, specifically in the transition towards 100% renewable supplied networks and through intentional islanding the drive towards 100% renewable powered islands capable of increasing network resilience (when necessary) by ensuring security of supply. The development of flexible heating and transport technologies in addition to the uptake of distributed generation, will prove vital in the transition to 100% renewable networks with the capability to operate flexibly and reliably.

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