# USING ELECTRICAL ENERGY STORAGE TO SUPPORT CUSTOMERS UNDER FAULTED NETWORK CONDITIONS

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## *ABSTRACT*

*As load grows and demand on double circuit distribution networks increases, there is an increased probability that under (n-1) fault conditions it would no longer be possible to supply all customers at peak times without infringing the thermal ratings of components on the remaining single circuit. Under such circumstances, expensive network reinforcement could be required.*

*One alternative could be to install an electrical energy storage (EES) system at a critical point on the network.. This could enable customers to continue to be supplied, even at peak times, for 1-2 hours, giving time for extensive lower voltage reconfiguration to take place. This paper describes how such a system would work, investigates optimum battery size, and evaluates the likely benefits that could occur, both for customers and for the DSO, as a result of its implementation.*

## INTRODUCTION

The use of battery storage to enhance the performance of electricity distribution networks is well documented. Strategic deployment of electrical energy storage (EES) can allow the deferral of, and in some cases can negate the need for, high-cost network reinforcement. Studies of this kind, which are reviewed below, generally assume that the network is intact with no planned outages or faults on the system.

However, EES can also bring benefits on occasions when the network is disrupted. Under these circumstances, the number of customers who can be re-supplied at any time, and especially at times of peak load, is likely to be limited by the thermal ratings, and consequent maximum capacity, of certain critical sections of the network. Increasing this number would constitute an improvement in quality of service, and may be required by the national industry regulator. In some circumstances, this requirement could involve costly capital expenditure, for example to re-conductor an overhead line or underground cable to a higher static thermal rating. Previous work on measuring and mitigating such network risk is reviewed below in 'Background: Network Risk'.

However, if supplementary energy supplies are made available from EES, then the number of customers supplied during such an event can also be increased. This can be achieved by the smart deployment of a battery storage system. The composite methodology for combining EES technology with network risk assessment is described under 'Composite methodology'.

This methodology is illustrated by a case-study, described in the following section, which also calculates the supply shortfall that would be expected under faulted conditions. The potential impact of EES is then outlined, and the potential of different sizes of EES system to reduce the risk of customer disconnection is calculated. The final section draws conclusions from the case study, in particular as regards the potentially wider use of EES technology and the associated methodology.

## Background: Electrical Energy Storage

The benefits of energy storage systems in distribution networks, including reducing customer minutes lost, assisting in compliance with energy security standards, arbitrage and restoration, have been summarized in [1]. Using EES to support post-fault reconfigured networks was described in [2], which also referenced a number of further studies. The impacts of EES on enhancing system reliability with renewable sources were quantified in [3]. A hypothetical system was used to perform a case study. Simulation result showed that an EES system can reduce loss of load expectation and loss of load energy expectation significantly and thus have a positive impact on system reliability.

## Background: Network Risk

The need to meet European low carbon targets by substantially increasing the proportionate use of electricity in both transport and domestic heating is well established [4,5]. As electricity consumption increases during the period 2010-2030, distribution networks will also become more heavily loaded, particularly at peak times. The UK standard which details the maximum allowable level of network risk is P2/6, endorsed by the industry regulator OFGEM [6]. Specified for different load sizes are the maximum permissible customer disconnection times in the event of a first circuit outage (n-1), and for larger loads, in the additional event of a second circuit outage (n-2). If these requirements cannot be met, then the network is no longer compliant with P2/6. This situation has been the subject of earlier research [7].

Any mitigation measure which can reduce the level of network risk, or postpone the date at which the network becomes non-compliant, can enable high cost capital investment to be deferred or even avoided altogether. One such measure could be provided by EES, and the composite use of it to mitigate network risk is the subject of the present paper.

## Composite Methodology

Under faulted conditions, one or more circuits in a power distribution network are unavailable to carry electrical energy to meet customer demand. In these circumstances, a new power flow equilibrium is established, in which one or more unfaulted circuits will be carrying more power than under normal, network intact operation. This increased power flow may exceed the capacity of one or more of the circuit components – transformer, switchgear, overhead line or underground cable.

In this event, typically an alarm will sound in the network control room, warning the network operator to offload the overloaded component. In certain configurations, this offloading may be carried out automatically. Where the degree of overloading is above a critical value, the circuit breakers protecting the component will be set to trip automatically. Following any or all of these responses, there may be a number of customers disconnected for a length of time, until mitigating action can be taken, including possible repair of the original cause of the fault.

However, if EES were installed on the customer side of the capacity restrictions, it could make up a proportion of this shortfall in customer supply, depending on the output power flow rating and on the energy storage capacity of the battery. At the end of the evening peak demand period, the battery would be depleted to an extent, but could be recharged during the night in preparation for the following day's peak, if the fault which required the use of the battery had not been repaired by that time.

An earlier case study looked at the use of EES to enable the reconnection of customers in the event of (n-2) loss of all higher voltage supply [2]. This case study was based around the actual installation of an EES facility (2.5 MVA, 5.0 MWh) at a test site in the North East of England. This EES facility forms part of the Customer Led Network Revolution (CLNR), a low carbon technology initiative sponsored by the UK regulator.

The case study which follows extends this approach by applying it to a location where EES has not been installed, but where the (n-1) loss of a single one of the two duplicate higher voltage supply circuits could lead to customer disconnection, if not at the present time, then certainly after a number of years of projected load growth.

# CASE STUDY

Primary substations 'A' and 'B' together serve over 16000 customers in the North of England, with a present peak demand of over 34 MW. They are supplied by two independent teed 33 kV circuits as shown in Figure 1. These supply circuits each consist of underground cable for the first 2.9 km, followed by 1.6 km of overhead line to the tee. These sections of overhead line are the most critical as regards static ratings.

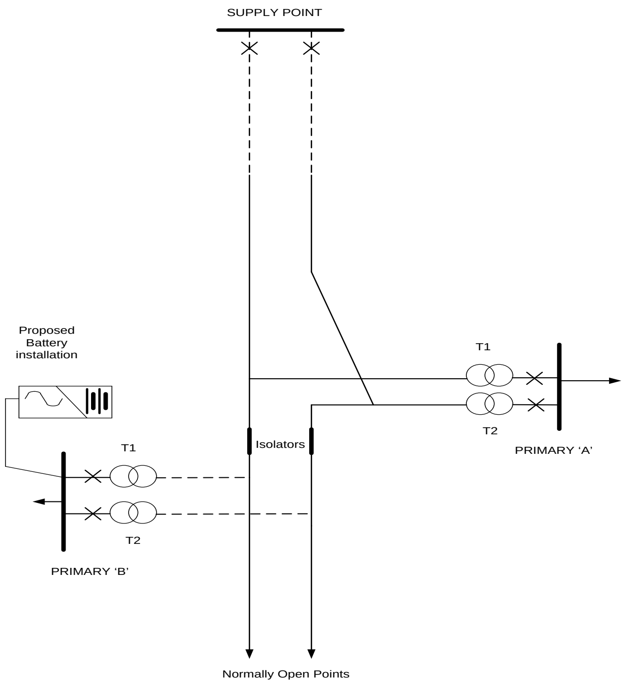


*Figure 1 – Schematic of supply circuits*

In the event of a fault on one of the two circuits, the remaining circuit would be required to carry the full load to both primaries. The critical section of both circuits is 175 $mm^2$ ACSR overhead line, with static ratings of 30.8 MVA (winter), 28.6 MVA (spring/autumn) and 24.7 MVA (summer). Analysis of actual half hourly load data for the 12 months from August 2011 to July 2012 indicates that the summation of load at both primaries reached peak values of 33.28 MVA in winter (January 18), 29.29 MVA in spring (April 25), and 27.86 MVA in summer (May 1), all of which are in excess of single circuit static rating.

This shortfall in capacity is increased by two further factors. The first is that no allowance has been made for losses. A power of 33.28 MVA passing through the four 33/11 kV transformers requires a significantly larger power to be transmitted by the overhead lines between the Supply Point and the tee. This excess will be even greater if the full load is being carried by a single circuit.

The second factor is demand growth. Whether this is assessed at 0.5% per year as presently assumed, or at a larger value to allow for accelerating take-up of electric vehicles and domestic heat pumps, the disparity between peak loads and static ratings can be expected to increase throughout the remainder of the decade and beyond.

### Estimating the shortfall

Detailed analysis of the half hourly data for August 2011-July 2012 has been carried out, based on the following assumptions:

- Losses between the critical sections of overhead line, and the 11 kV side of the transformers at both primaries are around 0.95% with the network intact. Since losses are generally proportional to the square of the current in any circuit, with the network operating in (n-1) mode overall losses double, to 1.9%.
- Demand in any half hour throughout the year increases at an annual linear 0.5%, leading to an increase of 3.5% for 2018-19 as compared with the recorded value for the same half hour in 2011-12.

On this basis, for example, the peak winter demand would be estimated to occur at 1800 on 18 January 2019, and to be equal to 33.28 MVA, increased by 3.5% to give 34.44 MVA at the transformers, and further increased by 1.9% to give 35.10 MVA on the remaining circuit under (n-1) conditions. This demand is 4.30 MVA in excess of the winter static line rating of 30.8 MVA.

Applying the same methodology to the whole estimated day, 18 Jan 2019, demand would be expected to exceed 30.8 MVA for 4 hours, from 1700 to 2030 inclusive, with a calculated total energy shortfall of 8.75 MWh.

Applying the same methodology throughout January, there is an expected shortfall for at least one half-hour period on every weekday, giving 21 days with expected shortfall. Repeating this calculation for each month gives the results shown in Figure 2. It is of interest that some of the summer months are as critical as January, with lower levels of demand being matched by lower static line ratings. In total, there could be expected to be 146 days through 2018-19 on which shortfalls would occur in the event of a (n-1) fault

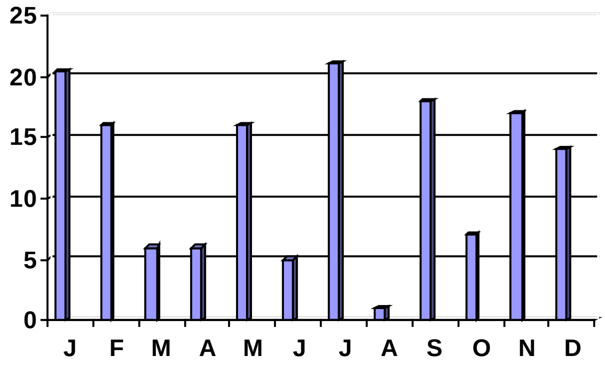


*Figure 2 – Number of days in each month of 2018-19 with expected shortfall*

## POTENTIAL IMPACT OF EES

The trial of a 5.0 MWh, 2.5 MVA EES system at the test site, as previously described, is ongoing. The following analysis assumes that a similar system is installed connected to the 11 kV busbars at Primary 'B'. The ability of the EES system alone to secure the shortfall is a function of both the power rating of the converters, and the energy storage capacity of the unit. For example on 18 January 2019, the expected worst day of winter, the shortfall would last from 1700 until 2030, and would be in excess of 2.5 MVA from 1730 to 1900 inclusive, a total of 2 hours, as shown in figure 3. With peak converter power of 2.5 MVA, the shortfall could be fully secured for 0.5 hours, then partly secured for 2.0 hours, then fully secured for a further 1.5 hours.

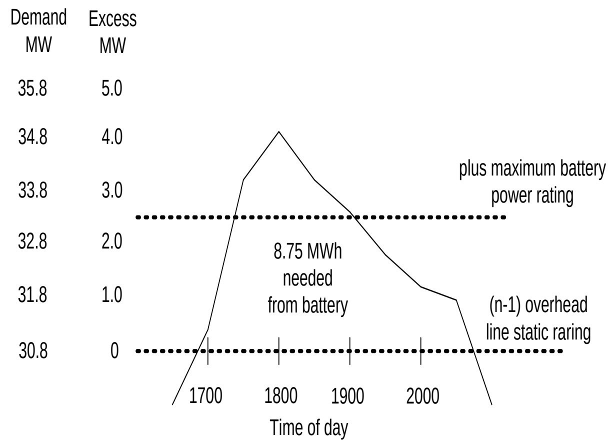


*Figure 3 – Shortfall predicted, 18 January 2019*

The total energy shortfall on 18 January is 8.75 MWh, which is almost double the assumed battery capacity of 5.0 MWh. As regards energy, only the first 1.8 hours of shortfall could be secured.

For smaller power shortfalls, the converter can be operated at below capacity, and thus support an energy shortfall of longer duration.

The situation in summer could be still worse, with shortfalls on 1 May 2019 estimated to last from 0800 until 2100 inclusive, with a peak power shortfall of 4.48 MW, and total energy shortfall of 25.75 MWh, over 5 times the battery capacity. However, even when the battery on its own could not secure total demand, it would usually be able to operate for sufficient time – up to 2 hours at full power – to allow remote or manual switching operations to be carried out, and thereby to secure supply indefinitely.

This illustrates an important aspect of the project, namely that the installation of an EES system could form part of a larger solution which would secure customer supply at both primaries.

**Effect of EES system size**

Analysis of power and energy shortfalls on the 146 days per year on which an energy shortfall could be expected for part of the day in the event of (n-1) loss of a single circuit has been carried out, and the results are shown in Table 1. The duration of the shortfall period, which is not shown in Table 1, ranges over those 146 days from a minimum of 0.5 hour up to a maximum of 13 hours. It is assumed that the time between shortfalls (at least 11 hours, with load levels well below peak) allows the EES to be fully recharged for any combination of converter size and storage capacity.

The numbers in the body of Table 1 indicate the number of days on which energy and peak power shortfalls fall within a given range. So, for example, there were 21 days within the projected year 2018-19 when, in the event of an (n-1) fault, the energy shortfall would be between 1.0 and 2.0 MWh, and the peak power shortfall would be between 1.0 and 1.5 MVA.

*Peak power shortfall (MVA)*

| *Energy shortfall (MWh)* | 0.0-0.5 | 0.5-1.0 | 1.0-1.5 | 1.5-2.0 | 2.0-2.5 | 2.5-3.0 | Over 3.0 |
|---|---|---|---|---|---|---|---|
| 0.0 - 1.0 | ***22*** | ***18*** | ***3*** | | | | |
| 1.0 - 2.0 | ***1*** | ***5*** | ***21*** | | | | |
| 2.0 - 3.0 | | | ***3*** | ***5*** | ***2*** | | |
| 3.0 - 4.0 | | | ***2*** | ***4*** | ***7*** | | |
| 4.0 - 5.0 | | | ***2*** | ***1*** | ***7*** | ***1*** | |
| 5.0 - 6.0 | | | ***2*** | ***1*** | ***5*** | ***1*** | |
| 6.0 - 7.0 | | | ***1*** | ***3*** | ***2*** | ***3*** | ***1*** |
| 7.0 - 8.0 | | | | ***1*** | | ***2*** | ***3*** |
| 8.0 - 9.0 | | | | ***2*** | | ***1*** | ***2*** |
| 9.0-10.0 | | | | ***1*** | | ***1*** | |
| Over 10.0 | | | | ***1*** | | ***6*** | ***3*** |

*Table 1 – Number of days with specified energy and peak power shortfalls.*

Table 1 can be used to evaluate the effectiveness of a converter and battery of the size installed at the trial site (2.5 MVA and 5.0 MWh). By totalling cells, it can be seen that on 103 of the 146 days this EES system would be able to meet the whole shortfall. On 19 of the remaining days its converter power rating would be sufficient, but not its energy storage capacity. On 1 of the remaining days, the energy storage capacity would be sufficient, but not the converter power rating. On the remaining 23 days, neither would be sufficient.

On this basis, Table 1 can be used to reach decisions about EES system size. The test site system secures load on 103 days, and this could be increased by 8 days for a 1.0 MWh increase in battery size, or by 14 days for a 2.0 MWh increase. Beyond this, the benefits decrease substantially. As regards converter capacity, the 2.5 MVA maximum appears suitable, with no significant gain from increasing it, but significant loss from decreasing it.

## CONCLUSIONS

. The possible installation of an EES system connected to the secondary busbar at a primary substation has been described and evaluated in terms of reducing the risk of customer disconnection following an (n-1) fault. The number of days per year on which such risk could be eliminated is shown to be a function of the size of both the converters and the battery.

Detailed economic evaluation of electrical energy storage as a means of risk mitigation shows that such mitigation could not, on its own, justify the battery installation. However, it could contribute towards an economic justification which included other potential benefits of an EES system.

The risk mitigation potential of EES could also be further enhanced by combining it with other smart grid technologies as part of a larger solution. Such technologies include network automation, real time thermal ratings, strategic use of generation, and demand side participation.

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