Customer-Led Network Revolution

Developing the smarter grid: the role of industrial & commercial and distributed generation customers

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Contents

Abstract

This report covers the aspects of the CLNR project that tested the level of flexibility customers can offer in how they generate and use electricity. It is one of two customer flexibility reports; this report (CLNR-L247) covers industrial and commercial (I&C) customers and distributed generators (DG) and the other report (CLNR-L246) covers residential and small and medium enterprise (SME) customers. The key findings in relation to our I&C and DG customer research are as follows:

Static demand-side response – The April 2010 tariff reform, which led to the introduction of the peak pricing signals in the common distribution charging methodology (CDCM), has had little impact on the behaviour of customer electricity consumption patterns and, four years later, still only about 5% of half-hourly customers see the peak pricing signals in the form of the red/amber/green DUoS tariff time bands in their electricity bill. Suppliers put this down to their customers wanting simplicity. The aggregate profile of I&C customers does not actually exhibit a peak in the red time band as it tends to fall away from 16:00 onwards. However, any reduction that this sector can make during this period would serve to offset the residential peak and so it would be useful if energy suppliers could actively promote multi-rate tariffs to this group that mirrored the DUoS time bands.

"On-demand" demand-side response – Our I&C DSR trials have shown that there is good potential for providing capacity to address post-fault peak-loading constraints at EHV and HV and there are no major barriers to its use by DNOs in locations where there are sufficient willing and flexible customers located downstream of a network constraint. This will not always be the case but, where it is, we recommend that DSR should be the first choice option for addressing constraints. The key issues to address to enable DSR to be become more prevalent relate to the task of identifying and signing up these customers, at a price that is efficient relative to the counterfactual reinforcement costs, in a market where there is competition with other users of DSR (i.e. National Grid STOR). An arrangement where different parties are able to share DSR resource may create value for all stakeholders and is under development by the ENA DSR sharing group.

This report provides the results of our trials, in which we recruited 17MW of DSR capacity, and describes a simple pricing methodology for setting a ceiling price based upon the counterfactual reinforcement scheme costs, years of scheme deferment, DSR set up and operating costs and the level of assumed DSR reliability. This gives an indicative ceiling price in the region of £17 per kW/yr or £2000 per MWh for a typical use case.

We found that it is easier to procure DSR from standby generation than find a truly flexible load but we also found that reliability from the generation sites was not as good, particularly when it came to availability which was only 50%. This will improve as providers get more used to the idea but it also highlights a need for more research to identify flexible loads. The loads that we used were refrigeration and gas compression - both of which provided 100% availability and 100% utilisation.

Generator voltage support – Operating generation in voltage control mode on a DNO network is an effective means of managing voltage through the control of reactive power. We have successfully trialed this with a 54MW wind farm and such an approach could provide an alternative to generator curtailment under certain circumstances.

Generator contribution to network security – A review of distributed generation profiles from a range of generation types has confirmed the contribution to system security as being appropriate as set out in "ENA ETR130 methodology for assessing the contribution of DG to network security" with the exception of wind turbines which we recommend should be reduced as follows:

Wind farms	Persistence T_m (hours)						
	0.5	2	3	18	24	120	360
ENA ETR 130	28%	25%	24%	14%	11%	0%	0%
CLNR trials	19%	15%	14%	8%	6%	0%	0%

Wind farm F factors: Comparison of ETR 130 figures against CLNR calculations

With respect to the overall methodology for calculating the contribution to security we recommend that a fully probabilistic risk-based planning approach be developed, using information from CLNR test cell 8, to support the "Review of ER P2/6 Working Group" of the Distribution Code Review Panel on the review of ETR 130 methodology for assessing the contribution of DG to network security.

1 Executive summary

The Customer-Led Network Revolution (CLNR) has involved successful delivery of an ambitious programme of work over a four-year period. The project learning will support distribution network operators (DNOs) in finding cost-effective ways to manage the introduction of low carbon technologies like solar PV, heat pumps and electric vehicles and to ensure customers continue to receive a safe, secure and affordable electricity supply now and also in a low-carbon future. It was led by Northern Powergrid in partnership with British Gas, Durham University, Newcastle University and EA Technology Ltd.

A key aspect of the project was to test the level of flexibility that customers can offer in how they generate and use electricity and to explore how this can help distribution network operators to facilitate the transition to a low carbon economy at the most economic long-term cost for customers. To achieve this, the CLNR project set up a number of trials to enhance the understanding of existing and future customer generation/demand profiles and the potential flexibility of different customer types.

This report is written for DNOs, regulators, energy suppliers, transmission operators and aggregators as well as customers that wish to engage with the electricity market through the provision of ancillary services such as demand-side response and it focuses on the CLNR lessons from our industrial & commercial (I&C) trials in the following areas:

Static demand-side response – Analysis of half-hourly customer consumption patterns to understand whether the April 2010 tariff reform, which led to the introduction of the red, amber, green time-of-use (ToU) pricing signals in the common distribution charging methodology (CDCM), has had any impact on the behaviour of customer electricity consumption patterns (Test Cell 7);

On-demand demand-side response – Demand-side response trials with a range of industrial and commercial (I&C) customers to test different recruitment methodologies, commercial arrangements and methods of operation (Test Cell 18);

Generator voltage support – Operating generation in voltage control mode on a DNO network through the control of reactive power (Test Cell 19);

Generator contribution to network security – A review of generation profiles from a range of generation types and an evaluation of whether there is any need to amend 'ENA ETR130: Application Guide for assessing the capacity of networks containing distributed generation' in respect of distributed generation contribution to system security (Test Cell 8).

The key findings in these four specific areas are as follows:

1.1 Static demand-side response - Impact of the 2010 tariff reform (Test Cell 7)

Durham University reviewed the electricity consumption of half-hourly metered HV and LV customers in the year before and the year after the introduction of the 2010 tariff reform. The analysis showed that the introduction of the CDCM Red/Amber/Green time bands in 2010 has not had a statistically significant effect on the number of units consumed during the peak load period by the half-hourly metered customers in Yorkshire and the Northeast.

This finding is supported by Northern Powergrid's high-level analysis of overall consumption between the CDCM price bands, which has shown that the proportion of electricity consumption between bands has remained broadly constant since 2010. This could be due to a number of reasons:

- Customers either choosing or not being offered a multi-rate retail tariff to reflect the underlying distribution use of system (DUoS) red, amber, green time bands resulting in less than 5% of half-hourly customers being on a multi-rate tariff;
- customers preferences for the certainty and lack of complexity of a flat retail tariff; and
- the nature of the I&C load profile which does not have an evening peak and actually starts to fall away from 16:00 onwards.

From a survey of energy suppliers we found that only a small percentage of customers see price signals that encourage peak avoidance and the suppliers fed back that they would not wish to see the pass through of the DUoS pricing to be mandated.

A small survey of customers has shown most to be on flat retail tariffs but we also found that some customers on a multi-rate tariff may be more concerned with achieving overall energy efficiency than with the relocation of load between time bands.

In order to capitalise on the potential for a shift of consumption from the red band to the amber / green bands it is recommended that energy suppliers give enhanced visibility to the benefits of peak pricing in some of their tariffs to enable half-hourly metered customers to benefit from the cost signals that they provide if they so choose.

We recognise that this may entail a billing related cost but such a move would provide additional incentive for I&C customers to permanently reduce load during peak load periods or would deliver additional value to those that wish to provide dynamic ancillary services such as load reduction or standby generator response.

1.2 "On-demand" demand-side response - Responsive load & generation trials (Test Cell 18)

This trial formed a major element of our I&C research. Sixteen I&C customers participated in the CLNR DSR trials in 2012 and 2014 during which different methods of recruitment, different contract and payment arrangements and different methods of sending the DSR signal were trialled. The key conclusions from the trials are as follows:

I&C DSR gives the DNO potential to defer or avoid primary network reinforcement investment

- I&C DSR should *always* be considered as an option to address forecast network constraints and a ceiling price can be calculated based upon the price of the lowest cost alternative;
- The main use case to be adopted by Northern Powergrid in the RIIO-ED1 period is likely to be a *post-fault response* to manage the security of supply at forecast EHV constraint points (i.e. primary substations forecast to be occasionally over its firm capacity during the winter evening peaks). It could be activated following a fault on the network that either occurs during, or cannot be restored before the onset of, the winter evening peak.

- Traditional reinforcement tends to provide capacity in discrete blocks which might sometimes be greater than actually needed. DSR provides the option to secure relatively small increases in capacity to meet the forecast demand and the amount of DSR capacity contracted each year can be amended up or down depending upon the actual load growth experienced and the DSR capacity available.
- DSR provides the option for DNOs to continue to defer reinforcement until a point is reached when no further capacity can be purchased to meet the forecast load growth.
- In some cases, DSR can eliminate the need for reinforcement altogether, and hence prevent sunk costs, if the actual load growth turns out to be less than that forecast. DSR contracts can be reviewed if the need goes away and so it provides a significant "option" value.

DNOs require DSR provision in specific geographic locations and this will be a challenge, requiring DNOs to improve engagement techniques to seek out and secure the resource that is available

- Locating customers that are willing to offer the level of DSR response required by DNOs is a significant challenge. The frequency of call off is likely to be low but, when it is required, it could be for four hours a day and be needed for more than 10 days until normal network capacity is restored. This will limit the number of customers that are capable or willing to participate in these schemes unless there are sufficient providers to allow the response to be sequenced around the available resource.
- When recruiting customers, the initial customer drop-out rates can be high due to issues with contacting the sites, contacting the right person at the site, the size of a site's flexible load / generation and the nature of the service required. This is a particular problem when targeting a tight geographic area where the number of suitable customers could be quite low. More work is required for the DNO (or its Aggregators) to improve knowledge of connected customers to enable more efficient targeting but also to increase the knowledge of DSR amongst customers.
- We have found that the DNOs can build effective relationships with suppliers and with commercial aggregators for the purpose of providing demand side response (DSR). We also engaged directly with one large customer and believe that it is possible for DNOs to build effective direct relationships with, for instance, the energy managers of national companies that operate multiple sites across the DNO regions and with the larger single site businesses.
- The DNOs are newcomers to the DSR market and are effectively in competition with other products such as the National Grid short-term operating reserve (STOR) and the recently introduced demand-side balancing reserve (DSBR) to mitigate the capacity margin squeeze. The key difference is that the DNOs are geographically constrained whereas National Grid has more choice and the flexibility on which providers to call. An arrangement where the DNO, Transmission System Operator (TSO) and even Transmission Network Operator (TO) are able to share DSR resource may create value for all stakeholders and is under development.

The DSR reliability levels experienced during the trials means that DNOs need to over-procure to achieve the required level of network security

- The CLNR DSR contracts for the 2014 trials delivered an overall reliability of between 43% and 83%, depending on how we include the sites that declared themselves unavailable for the whole of the trial.

- A probabilistic approach is therefore needed when planning, pricing and purchasing DSR by applying a de-rating factor to account for combined availability and utilization reliability.
- Reliability could be improved if the response can be provided by a portfolio of customers to deliver the overall DNO requirements, each contributing towards the total requirement.
- Aggregators advise us that presently the lowest DSR capacity to make it worthwhile for their involvement is of the order of 250kW to 500kW per site.

The contract arrangements need to be simple to understand, simple to operate and they must offer a fair price to the provider and the DNO in order to be viable

- Customers that are already participating in STOR are a natural first choice for recruitment, provided that product sharing arrangements[1] can be established, as they are already knowledgeable about the concepts of DSR. This makes establishing the contracts a much more straight forward process.
- Otherwise, the lead times from making initial contact with a customer to finalising a DSR contract can range from 12 to 24 months for those customers not already familiar with the concept.
- The CLNR trial established that customers were willing to sign contract terms and prices broadly equivalent to STOR for the purpose of the trial with a guaranteed 10 calls. However, this may change given the likely lower frequency of utilisation under our DNO use case scenario.
- There is therefore a balance to be struck which depends upon the risk appetite of both the DNO and the provider. Based upon an analysis of primary fault records we estimate that the key parameters will be an availability window of all the 83 weekdays between November and February and a call duration of four hours with the number of calls averaging two per annum (but it could be as low as zero or occasionally higher than 10 events).
- The DNO may calculate, on a project by project basis, the maximum £ per MW per year that it is able to pay, based upon a comparison with the price of the lowest cost reinforcement alternative. The actual price struck will be driven a number of factors :
    - Customers are looking for a bankable business case with guaranteed returns from their investment to cover the cost of the required metering, protection, controls, management time, operation / administration time and also changes to business practices and processes if they are offering a load reduction.
    - DNOs need to consider the cost of the actual deferred / avoided reinforcement, the size of the available DSR capacity, the number of potential providers, the aggregated response reliability, the timescales by which it will be needed, the timescales over which it will be needed and any requirements that the regulator sets on how the benefits should be shared between the DSR provider and all DUoS paying customers.

[1] Customers had to temporarily drop out of STOR for the duration of the trial

It is easier to procure DSR from standby generation than find a truly flexible load

- DSR from standby generation is currently easier for a DNO to find and sign-up than DSR from load reduction.
- Out of the 16 trial customers, we were successful in finding two effective and fast responding flexible loads. The first was provided by refrigeration plant operated by an ice manufacturer (0.6MW) connected at HV and the second was a gas compressor (5MW) connected at EHV. Such load types, particularly refrigeration, offer good potential for demand-side response as the DSR can be accommodated without disruption to working patterns.
- Standby generation appears to be the most available and successful entry point for I&C customers wishing to participate in DSR schemes as it provides a new revenue stream while minimising the number of changes and new risk to their business operation.
- Following this first step, customers may then consider engaging in developing DSR via load response, which may be more costly to set up and could be more intrusive to their core processes.
- The DNO sector needs to explore more fully the barriers to engaging more load turn-down resource in the RIIO-ED1 period and beyond.

1.3 Generator voltage support (Test Cell 19)

Generators that have a capacity between 50MW and 100MW are classed as “Medium Embedded Power Stations” which makes them subject to certain Grid Code compliance requirements, one of which is to have a reactive power capability covering both lagging and leading power factors and to operate in “voltage control mode”. This allows the generator to control the flow of reactive power to maintain voltage within limits as real power output is increased. This facility is historically used by National Grid to manage the voltage on the 275kV and 400kV systems but has been trialled on CLNR with a 54MW wind farm connected at 66kV as an alternative to constraining the generator off. The trial has shown this technique to work successfully and we will review our policies in early 2015 after a full 12 months of operation to include this method for wind farms willing to invest in the STATCOM equipment required to provide this mode of operation.

1.4 Generator contribution to network security (Test Cell 8)

Durham University analysed the output from 62 distributed generation sites in Yorkshire and the Northeast over a period of two years and EA Technology Ltd undertook a further analysis of the profiles. The purpose of these reviews was to:

a) Establish whether general classes of generation exist that can be distinguished by their generation profiles;
b) Review the current methodology for assessing the contribution of distributed generation to network security and make recommendations on whether the approach should be updated;
c) Consider whether the improved accuracy delivered by the analysis of a greater number of sites than used in the original ETR 130 study would lead to a recommendation to change any of the reliability factors (F factors) used to determine the security contribution from generators.

With regard to the generation profile characteristics, Durham University found that there were distinguishing features between different types of generation:

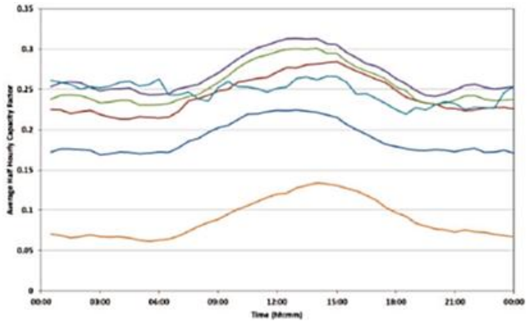

Figure 1.1: Wind Generation

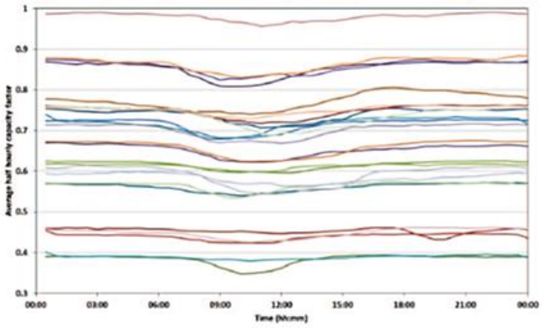

Figure 1.2: Landfill

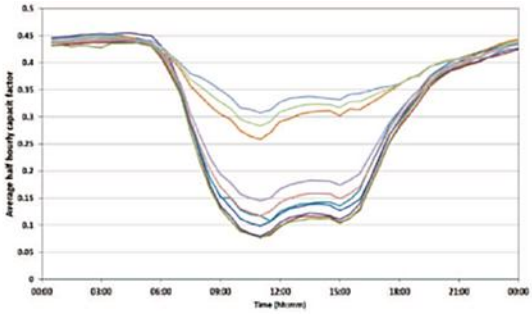

Figure 1.3: CHP - Hospital

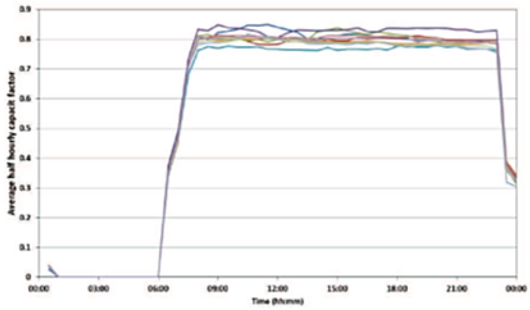

Figure 1.4: CHP – Block of flats

There are two key recommendations with respect to the review of ETR130:

- To update the current F factors for the contribution of different distributed generation (DG) technologies to distribution network security based on the data collected from the customer field trials of the CLNR project.
- To use the information collected from the customer field trials and associated learning outcomes of the CLNR project to support the "Review of Engineering Recommendation (ER) P2/6 Working Group" of the Distribution Code Review Panel and the review of Engineering Technical Report (ETR) 130 methodology for assessing the contribution of DG to network security.

With regard to the F factors, EATL found that for intermittent generation such as wind farms they should be lower than in the original study, which would reduce wind generation's contribution to network security planning considerations, as follows:

Wind farms	Persistence T_m (hours)						
	0.5	2	3	18	24	120	360
ETR 130	28%	25%	24%	14%	11%	0%	0%
CLNR trials	19%	15%	14%	8%	6%	0%	0%

Table 1: Comparison of the F factors of wind farms from ETR 130 against the 16 CLNR monitored wind farms

For other, more controllable generation such as landfill gas, CHP, gas, biomass and small hydro, the F factor calculations from the CLNR trials were broadly similar to those in ETR 130.

The security of supply standard for the planning and design of distribution networks suggests that "the contribution to System Security from DG plant specified in ER P2/6 and ETR 130 have been derived from the best data available at the time. Therefore, in the event that more accurate data becomes available it may be appropriate to review the contributions quoted in ER P2/6 and ETR 130". In this respect, it is recommended to update the current F factors for the contribution of different DG technologies to distribution network security based on the data collected from the customer field trials of the CLNR project. This supports DNOs to better recognise the contribution that DG makes to the system security and therefore to comply with the security requirement ER P2/6. It should be noted that the data used to derive the revised F factors is based only on generators in the Northern Powergrid licence areas.

With respect to the overall methodology for calculating the contribution to security we recommend that a fully probabilistic risk-based planning approach be developed, using information from CLNR test cell 8, to support the "Review of ER P2/6 Working Group" of the Distribution Code Review Panel on the review of ETR 130 methodology for assessing the contribution of DG to network security.

The consideration within the CLNR project of the modelling structure underlying ETR 130 reveals a number of concerns about how the planning methodology contained therein relates to the real system situations under study. In general, if a simplified approach (such as the F factors used at present) is to be used in assessing the contribution of DG and other new technologies in practical planning, then such a simplified approach should have a sound basis in a particular risk calculation relevant to the real network situations under study. This might either be based in a probabilistic calculation with a particular target risk level, or in a probabilistic cost-benefit analysis between investment cost and future reliability cost. More generally, there is no natural way of extending a deterministic standard such as the present ETR 130 and P2/6 to include distributed resources. The only natural basis for considering such new components of the system is to develop a fully probabilistic risk-based planning approach, which can integrate consideration of all relevant technologies. There are clear advantages of using a simplified approach such as the present F factors for practical purpose (including resource expended on any individual study, and applicability by a wide range of planning engineers who may not have experience in probability techniques), but in order to have confidence that such an approach will deliver good results it should have a sound basis in a fully detailed calculation. Hence, it is recommended to make use of the information collected from the customer field trials and associated learning outcomes of the CLNR project to support the "Review of ER P2/6 Working Group" of the Distribution Code Review Panel on the review of ETR 130 methodology for assessing the contribution of DG to network security.

2 Introduction

2.1 Purpose and scope of this paper

The purpose of this paper is to disseminate the learning from the Customer-Led Network Revolution project with respect to the flexibility services that industrial & commercial (I&C) customers and distributed generators can provide to help distribution network operators efficiently manage network constraints to keep future reinforcement costs down for the benefit of all customers.

2.2 Background

The UK Government has set some ambitious goals for reducing the amount of greenhouse gases that we as a country emit into the atmosphere. The achievement of these goals will require a dramatic change in how electricity is produced and used, which will have a profound effect on the way that electricity distribution networks are operated in the future.

In summary there are three broad UK government policy objectives[2] that will impact the electricity system:

- **Carbon reduction targets:** The achievement of 2020 and 2050 carbon reduction targets[3] is likely to require the almost complete decarbonisation of the electricity sector.
- **Energy security:** There is a need to ensure secure and sustainable energy supplies as the power system decarbonises and electricity demand changes.
- **Affordability:** This will have to be achieved while ensuring that networks continue to deliver long term value to existing and future customers.

The impact of these policy objectives upon the electricity system will be:

- **Integration of inflexible and intermittent generation**: As the GB national generation infrastructure is renewed, more electricity will be generated from less flexible sources such as nuclear and renewable sources that are intermittent e.g. wind.
- **Electrification of transport and heating:** The decarbonisation of transport will lead to an increase in the use of electric vehicles and reducing the use of fossil fuels for heating will see an increase in the use of heat-pumps in homes and businesses, both of which will result in load growth on the electricity distribution networks.
- **Integration and optimisation of Distributed Energy Resources:** There will be an increasing number of distributed generators connected to the distribution network as opposed to the transmission network, including at the domestic level. In some cases this generation will be dispatchable by the transmission system operator whilst the remainder will be of a size that

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[2] ENSG "A smart grid routemap" 2010.

[3] Climate Change Act 2008 stipulates that the UK must reduce its CO_2 emissions to 34% lower than the 1990 levels by 2020 and 80% lower by 2050.

the customer will decide when they operate. Customers will be encouraged to participate in demand side response using their own demand, local storage and/or generation.

Although a lot of these changes to the electricity system will be at the demand and generation ends, the network that connects these together will have to be strong yet flexible. Distribution networks will have to be operated to respond to power flows that are more complex and less predictable.

This will involve making effective and efficient decisions in how the network is designed and operated so as to minimise the impact on customers' bills while maintaining high levels of network reliability. This requires all distribution network operators (DNOs) to find the best deal for customers in the long-term by seeking out and deploying novel solutions when economic, avoiding too much investment ahead of need but being ready for the accelerated uptake of these technologies when it happens in terms of investment and resource planning.

2.3 The Customer-Led Network Revolution project

The Customer-Led Network Revolution project, funded via the Low Carbon Networks Fund, was a smart grid project led by Northern Powergrid in partnership with British Gas, Durham University, Newcastle University and EA Technology designed to test a range of customer-side innovations (innovative tariffs and load control incentives) alone and in combination with network-side technology (including voltage control, real time thermal rating and storage). The project was designed to deliver robust learning that would be applicable to a high percentage of GB networks and demographic groups.

More than 13,000 domestic, SME, industrial and commercial customers and merchant generators took part in the project, which involved the trialling of innovative smart grid solutions on the Northern Powergrid electricity network and the trialling of novel commercial arrangements to encourage customer flexibility.

Learning from the project will help DNOs find cost-effective ways to manage the introduction of low carbon technologies (LCTs) like solar PV, heat pumps and electric vehicles and ensure customers continue to receive a safe, secure and affordable electricity supply now, and in a low-carbon future. The project tested the flexibility in the ways customers generate and use electricity and how DNOs can find ways to reduce customers' energy costs and carbon footprint in the years to come.

The project was designed to predict future loading patterns as the country moves towards a low-carbon future and to research novel network and commercial tools and techniques and to establish how they can be integrated to accommodate the growth of low carbon technologies (LCTs) in the most efficient manner. The project trialled new network monitoring techniques to measure power flow, voltage and harmonics, trialling alternative smarter solutions that employ active network management and customer engagement to increase network capacity and/or modify load patterns and it developed new planning and design decision support tools for engineers.

2.4 CLNR learning outcomes

To understand existing and future customer generation/demand profiles and the potential flexibility of different customer types we established customer trials, divided between a number of test cells, designed to deliver a specific set of five learning outcomes, as follows:

Learning Outcome 1: understanding of current, emerging and possible future customer (load and generation) characteristics;

- The project analysed the basic demand profiles of typical business and domestic customers and those with heat pumps, electric vehicles, micro-CHP and solar photo-voltaic panels using smart meter data and the more detailed disaggregation of some customer load profiles down to individual appliances using additional metering. This was done with the aim of updating the statistical analysis of the existing design standard for the design of low voltage radial networks (ACE49) to improve the planning of future LV networks and to provide a baseline against which to measure the impact of demand-side response interventions.

- Research was also carried out into the profile of various types of generation with the aim of updating the Engineering Technical Report ETR130 to better understand the network security contribution from generation.

Learning Outcome 2: to what extent are customers flexible in their load and generation, and what is the cost of this flexibility?

- We researched the development of various tariffs and other interventions for domestic and business customers with and without LCTs to test their willingness to provide a demand side response (DSR) to help reduce peak loading and prevent thermal and/or voltage issues on the electricity distribution network. The types of interventions tested were time of use and restricted hours tariffs and within premises balancing and direct control of smart appliances.

- We also tested demand side response (DSR) for industrial and commercial customers, contracting both via aggregators and directly with customers. The aim was to test whether such commercial propositions are attractive to customers and what level of confidence we can place on their response.

- We also trialled working with distributed generation in voltage control mode, using the controlled import/export of reactive power to control the voltage as an alternative to the curtailment of the generators under certain circumstances.

Learning Outcome 3: to what extent is the network flexible and what is the cost of this flexibility?

- Learning outcome 3 sought to understand to what extent the network is flexible and the likely cost of this flexibility. It involved trialling network technologies and an active network management (ANM) control system called the grand unified scheme (GUS) control system in a series of large-scale field trials. This control system is given control objectives, for instance to manage voltage or power flow and it then monitors relevant network parameters in real-time, runs network analysis to estimate states where measurements are not possible, determines the location of network issues and dispatches the optimum response based upon the types and location of the smart technologies available.

- Although the technologies trialled had previously been deployed individually at high voltages, this project delivered new learning on the deployment of technologies in combination, in conjunction with demand side response and at lower voltage levels.

Learning Outcome 4: what is the optimum solution to resolve network constraints driven by the transition to a low carbon economy?

- Learning outcome 4 sought to develop the overall optimum solutions to resolve future network constraints which could result from the transition to a low carbon economy. We considered optimum solutions for representative customer groupings and networks, and these solutions informed network design and were encapsulated in the prototype tool for network designers, Network Planning and Design Decision Support (NPADDS) tool.

- We combined data and analysis from learning outcomes 1, 2 and 3, with desktop modelling, simulation and emulation. This approach allowed us to model combinations and future scenarios and those which were unfeasible or not economically viable to pilot in the field.

- From this, we have established a merit order of solutions[4] to network constraints, taking academic learning and placing it firmly in an industrial context. Non-CLNR solutions were also considered, to create a comprehensive merit order of solutions and forge a coherent, wide-ranging view of how to design future networks. We considered opportunities and solutions and explained why, in practice, DNOs might take a certain policy stance. The conclusions are structured for easy incorporation into relevant policy documents, and they also inform the coding of the NPADDS design tool to ensure consistency with policy.

Learning Outcome 5: what are the most effective means to deliver optimal solutions between customer, supplier and distributor?

- The objective of learning outcome 5 was to provide a framework for transition of the technologies and interventions trialled by CLNR into business as usual (BAU). The outputs for DNOs, include:
    - the provision of a prototype software tool for network designers (NPADDS);
    - material for training courses;
    - new operational procedures to define safe working practices for new technologies;
    - design policy guidance;
    - equipment specifications and equipment application documents; and
    - recommendations to update national design standards.

- For the wider industry, this includes possible new commercial models and policy recommendations as well as an assessment of the value of these solutions to the customer.

[4] Which can be found in the CLNR-L248: Optimal solutions for smarter distribution systems

One key output is a tool for the toolkit, to guide network planners in selecting non-network, novel network and conventional network solutions. This will be built upon a better cost/benefit analysis tool, which we have developed as part of this Project (having identified the volume and cost of new solutions for releasing network headroom) and which can be used in itself to guide further work.

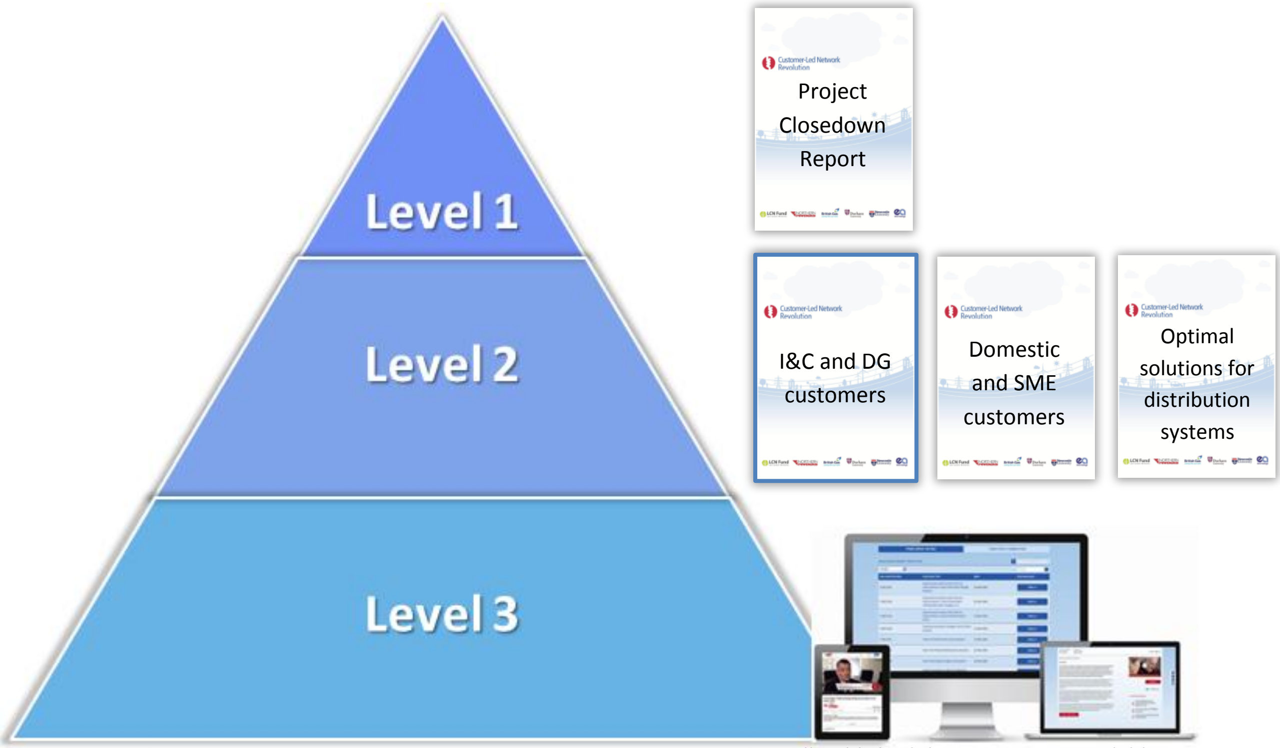
2.5 Structure of this paper

From this point onwards, the structure of this report is as follows:

- **DNO Flexibility Requirements** – the DNO use cases for demand side response services;
- **Forms of I&C flexibility** – the forms of flexibility already exchanged in the market at the I&C customer level;
- **Value of DSR to the DNO** – a methodology for valuing DSR compared to other project options;
- **CLNR trial findings for I&C customers and DG** - An overview of the CLNR trial purpose, methodology and findings in the following areas:
  - DUoS Tariff signals (TC7);
  - Generator contribution to system security (TC8);
  - On-demand I&C DSR trials (TC18) - Load turn-down & generator substitution;
  - I&C Ancillary Services – Voltage Support (TC19);
- **Commitment to pursue I&C DSR –** An overview of next steps for the application of DSR;
- **DSR tool kits** – Application guides for the valuation, procurement and operation of DSR, supported by training material, valuation spreadsheets and contracts.

2.6 How this paper fits within the full CLNR output suite

The diagram below provides an overview of the structure of the CLNR project output documents. This report resides at Level 2, as shown outlined in blue.



All published documents are available at:
http://www.networkrevolution.co.uk/resources/project-library/

The related level 3 documents are as follows:

Static demand-side response (TC7)	• CLNR-L087: Business (I&C) impact of 2010 tariff reform (report) • CLNR-L088: Business (I&C) impact of 2010 tariff reform (dataset)
Generator contribution to network security (TC 8)	• CLNR-L010: Initial load and generation profiles from CLNR (report) • CLNR-L011: Initial load and generation profiles from CLNR (dataset) • CLNR- L185: Review of the distribution network planning and design standards for future low carbon electricity systems (including recommendation for ETR130)
On-demand I&C demand-side response (TC 18)	• CLNR-L014: Initial report on CLNR Industrial & Commercial Demand Side Response Trials (2012) • CLNR-L098: Report on CLNR Industrial & Commercial Demand Side Response Trials (2014) • CLNR-L160: Application Guide - CLNR Demand Side Response Trials • CLNR-L258: Ceiling Price Calculator • CLNR-L173: DSR training material
Commercial Arrangements	• CLNR-L032: Commercial Arrangements - Phase 1 (2013) • CLNR- L145: Commercial Arrangements - Phase 2 (2014)

These documents provide more detail from the trials, including datasets, the results from customer surveys, example trial contracts, etc.

3 Customer flexibility – benefits & potential

3.1 Forms of demand-side management

Demand Side Management (DSM) is a broad definition that covers a range of techniques to modify the consumer demand on networks through various methods such as financial incentives, education, etc. DSM may reduce total energy consumption but its key value lies in providing a means to reduce the need for investments in networks and/or power plants for meeting peak demands if the load reduction is managed to reduce those peak demands.

Demand Side Response (DSR) is a subset of DSM and can be defined as "actions voluntarily taken by a consumer to adjust the amount or timing of their energy consumption in response to a dynamic signal" i.e. DSR actions are specifically in response to a dynamic signal which may be given at short notice; not to be confused with other DSM behaviour incentives which may involve following predetermined price incentives. DSR providers can achieve this reduction in demand by either reducing demand or by operating their standby generators to pick up load during the demand response period.

Examples of DSM include but are not limited to:

- Demand Side Response (DSR) as defined above;
- Energy Efficiency / Reduction;
- Energy Storage Services (Could be thermal storage, electrical energy storage, etc.);
- Distributed Generation;
- Dynamic Pricing;
  - Time of Use (ToU)
  - Location of Use (LoU)
- Increased or Flexible demand devices (Electric Vehicles and Heat Pumps);
- Dynamic Demand (e.g. super flexible loads such as hydrolysers)

3.2 DNO flexibility requirements

DNOs will increasingly need to seek demand side response services as a lower cost alternative to reinforcement in areas where the growth in loads such as heat pumps and electric vehicles begins to exceed network capacity at peak times. This is expected to start to become a more widespread issue for networks from about 2020 onwards. The circumstances under which a DNO can make use of demand side response services include the following:

- To create headroom for the growth in the connection of low carbon technologies and maintain peak loading within the rating of the network - for which a static ToU tariff or a restricted hours tariff would be appropriate to encourage a day-in day-out permanent peak reduction. Energy efficiency measures would also be useful here if they targeted appliances and devices that typically operate in the peak periods (i.e. a changeover to more efficient fridges, freezers, lighting, home entertainment, the insulation of electrically heated homes, etc.).

- To deal with an occasional peak load above rating, for instance a severe winter peak - for which a dynamic response would be required (e.g. Dynamic ToU tariffs, direct control, load turn down or generator substitution).

- To maintain firm capacity or restore customer supplies during peak load conditions after a fault when the system is running abnormally - for which a dynamic response would also be required (e.g. Dynamic ToU tariffs, Direct control, Load turn down, Generator substitution).

- A large load or generation connection where it may be possible to reduce the cost of the connection and also increase the speed of the connection through the application of a load or generation management scheme agreed with the connectee.

- A large load or generation connection where it may be possible to reduce the cost of the connection and also increase the speed of the connection through the application of a load or generation management scheme agreed with another connected customer identified via a localised capacity auction.

This report focusses on the flexibility of industrial and commercial customers and larger-scale distributed generators.

3.3 Forms of I&C flexibility

3.3.1 Tariff-based Time of Use DSR

There are specific Use of System charging methodologies that seek to encourage the avoidance of electricity consumption at peak times with the aim of avoiding the need to reinforce the transmission and distribution networks:

- **Transmission** - Transmission Network Use of System (TNUoS) charges or Triads
- **Distribution** - Common Distribution Charging Methodology (CDCM)
  EHV Distribution Charging Methodology (EDCM)

Triad charges are designed to avoid the reinforcement of the transmission lines that interconnect the generation in the north with the load in the south by basing the half-hourly TNUoS charges on the three half-hourly settlement periods of highest transmission system demand during November to February.

The distribution charging methodologies are designed to reflect the marginal reinforcement costs of the distribution system. They are broadly locational and are structured to encourage the avoidance of consumption at peak times:

- CDCM has three DUoS charging bands, GREEN, AMBER and RED with increasing unit charges for energy consumption in each band. These charging bands apply Mon to Fri all year round. The Northern Powergrid CDCM charges for HV and LV half-hourly metered customers are designed to discourage use in the 16:00 to 19:30 time period.

- EDCM has a SUPER RED band which applies Mon to Fri between November and February.

Section 4 of this report provides an important retrospective review of whether the introduction of the CDCM has caused a change in customer behaviour regarding electricity consumption during the peak (red band) period.

3.3.2 On-demand DSR (bespoke contract based)

The key demand side response services being used today are those procured by National Grid Electricity Transmission as System Operator, in order to balance electricity demand and supply and to ensure security and quality of electricity across the GB transmission system. This market is growing and so it would be useful if DNOs could access and share some of this resource.

Balancing services include buying or selling electricity as part of the balancing mechanism in the wholesale market but also a range of ancillary services to cover the following issues:

- Ensuring a stable frequency of transmitted electricity. NGET has an obligation to maintain frequency to within 1% of normal system frequency (50Hz). If demand is greater than generation, frequency falls, and vice versa **(Firm Frequency Response – FFR);**
- Ensuring there is reserve provision to increase supply or reduce demand in case of a sudden loss of a significant generation plant **(Frequency control by demand management – FCDM)**;
- Maintaining real and reactive power balance to stabilise the voltage profile across the transmission system **(Short-term operating reserve - STOR);** and
- Maintaining the security of the system, e.g. a system fault event may require the rapid reduction or disconnection of generators to maintain system stability **(Fast Reserve).**

Table 3.1 table below gives an overview of the main balancing services.

Firm frequency response (FFR)	An automatic change in active power **output or demand** in response to a frequency change. Services are procured through a competitive tender process, where tenders can be for low frequency events, high frequency events, or both.
Frequency control by demand management (FCDM)	To help to manage large variations in frequency, caused by e.g. the loss of a significantly large generation plant. The response is provided by an automatic interruption of **demand** customers, when the system frequency transgresses a low frequency relay setting.
Short-term operating reserve (STOR)	The provision of **extra power** through standby generation, and/or **demand reduction**, in order to be able to balance unforeseen mismatches in supply and demand.
Fast Reserve	This service requires a **faster delivery** than STOR, and can be used to balance supply and demand and control the frequency.

Table 3.1: Main National Grid Balancing Services

The provision of balancing services outside the balancing mechanism has created a role for aggregators. Aggregators provide balancing services, including STOR, fast reserve and frequency response, by aggregating the response of a number of generation and demand sites. The charts below show the National Grid's 2011 and 2020 forecast requirement for STOR services under the Gone Green scenario[5]. The charts highlight the need for new participants to enter the market in order to meet National Grid's anticipated future requirements.

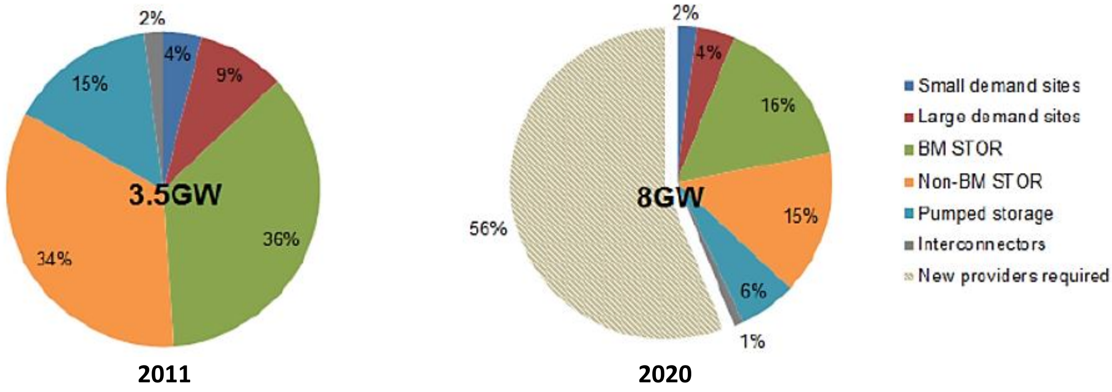


Figure 3.1: National Grid STOR requirements forecast

In order to provide STOR services; a minimum response of 3MW is required, hence the need for smaller sites that cannot provide this level of response individually to use aggregator services. Organisations with large sites that could provide a 3MW response may still choose to use an aggregator, due to the complexity of the contracting arrangements with National Grid Electricity Transmission.

The bulk of the aggregator's services are currently sourced through contracts with onsite generators, although increasingly aggregators are entering into turn-down contracts with demand sites (in the case of frequency response services the contracts with demand customers will include the ability to both turn down and increase demand).

The increasing requirement for balancing services, as shown in Figure 3.1 above, and the significant but disaggregated potential of demand side resource (i.e. there is significant untapped potential but it is spread over a large number of customers), promises a growing role for aggregators in future.

Currently there are a small number of aggregators operating in the GB electricity market. Some of the more established actors include; Flexitricity, KiwiPower, ESP, Open Energi, EnerNOC, Energy Pool.

Typically these aggregators provide balancing services to NGET and also additional services to demand customers, such as Triad management. There is increasing potential for DNOs to use aggregator services to reduce peak loads on the distribution network, either through turn-down of demand customers or use of onsite generation. These contracts are now becoming part of business-as-usual for DNOs where there are significant network capacity issues (e.g. London) and they are being trialled extensively elsewhere.

[5] UK Future Energy Scenarios, National Grid, November 2011.

The UK Demand Response Association has been created to represent the Demand Response industry participating in the UK with one voice on the subjects of developing and overseeing policies, strategies, objectives and plans for demand response and peak reduction programs and incentives. It is the mission of the Association to help develop technical standards and policy recommendations that allow demand response resources to participate in the energy and wholesale markets - focusing on existing programmes and opportunities and also encouraging development of new programmes.

This report provides an overview of the CLNR experience with trialling I&C DSR.

3.3.3 Flexible connections

Distribution network operators already offer non-firm connection agreements that constrain consumption or generation under certain network conditions. Under these arrangements the customer accepts the lower level of security in return for a lower connection charge and, in most cases, a faster connection. Northern Powergrid has commissioned approximately 20 automated generation management schemes that constrain generators off the network under specific network running and loading arrangements. This report does not cover these types of schemes but other LCN Fund projects have undertaken detailed research in this area.

3.3.4 Generator Voltage Support

Generators that have a capacity between 50MW and 100MW are classed as “Medium Embedded Power Stations” which makes them subject to certain Grid Code compliance requirements, one of which is to have a reactive power capability covering both lagging and leading power factors and to operate in “voltage control mode”. This allows the generator to control the flow of reactive power to maintain voltage within limits as real power output is increased. This facility is historically used by National Grid to manage the voltage on the 275kV and 400kV systems. Increasingly, voltage control has become a matter for DNOs, and has been trialled on CLNR with a 54MW wind farm connected at 66kV as an alternative to constraining the generator off. The trial has shown this technique to work successfully at reducing the number of constraints. We will review our policies in early 2015 after a full 12 months of operation to include this method for wind farms willing to invest in the STATCOM equipment required to provide this mode of operation. Section 8 of this report provides further detail on the trialling of this mode of operation.

3.4 Value of on-demand DSR to the DNO

3.4.1 Adapting policies to recognise on-demand DSR

The learning from CLNR recommends a change to design policies such that that on-demand DSR should always be considered when reviewing the potential options to manage a forecast network constraint at EHV / HV and DSR should be selected if:

- Sufficient DSR resource is available to provide a reliable response; and
- It is at least cost-neutral to the next most economical network solution.

Constraints at this level will be managed by procuring DSR from customers downstream of the forecast constraint, initially from industrial and commercial (I&C) customers. Research and development will continue into RIIO-ED1 to assess the potential for 'on-demand' DSR from residential customers to support the network and potentially address other types of network constraint.

3.4.2 The Northern Powergrid use case for DSR

Northern Powergrid's currently operates as business as usual a form of DSR via individual agreements with customers at the point of connection, particularly generators, where we are sometimes able to connect generators without network reinforcement by implementing an active network management (ANM) scheme to constrain the generator under certain network conditions. A new scheme has also been trialled and implemented with a wind farm operating in voltage control mode to reduce the need for constraint.

The discussions on such arrangements are relatively straight forward to initiate due to the nature of the relationship with the customer as we explore the best option to get them connected to the network. A key change going forward is to identify and build relationships with customers that are already connected for them to provide demand-side response services to cater for general load growth or for the connection of someone else's load requirements.

Northern Powergrid's initial use case for DSR from existing I&C load customers will be to engage with industrial and commercial (I&C) customers to provide DSR in the form of load turn-down or generator substitution to maintain ***post-fault security of supply at 132kV and EHV constraint points*** (for instance a highly loaded primary substation) ***following a fault on the network that either occurs during, or cannot be fully restored before the onset of a network peak***[6].

3.4.3 The advantage of DSR relative to traditional reinforcement

A successful DSR approach will defer or avoid reinforcement investment in the network, therefore providing financial benefit to the customers who deliver the DSR service, in the form of DSR payments; and, also to all other connected customers in the form of lower future DUoS charges due to the reduced reinforcement requirements.

There are particular advantages of DSR relative to the conventional network reinforcement solutions, as follows:

- When purchasing DSR, the DNO only needs to purchase the capacity it actually requires at the time that it is required rather than, as is the case in the reinforcement alternative, having to purchase the potentially higher discrete increments of capacity that one receives with, say, the replacement of a pair of primary transformers.
- The amount of DSR capacity purchased can be reviewed and gradually increased incrementally in line with the actual load growth rather than investing against a forecast. This approach ensures ongoing cost optimisation and can continue until there is no further available DSR resource;

[6] This peak could be a winter evening peak or a summer daytime peak.

- The existing DSR purchase contracts can be periodically reviewed, allowing the arrangement to be turned down or discontinued if not required in the future. This releases significant option value if the predicted load growth does not materialise or if it reduces for some reason. Such flexibility is also required if there is an eventual need to implement a network solution, for instance, due to the load growth continuing and eventually exceeding that which can be covered by the available DSR resource but one needs to strike the right balance to deliver sufficient certainty to encourage providers to enter into the market.

3.4.4 Business case for DSR

Given the varying costs of reinforcement and the variation in both substation load profiles and characteristics, the business case assessment for DSR will need to be completed on a case by case basis. Once a wider assessment has been undertaken to identify all the potential solutions an assessment of what price a DSR option would become cost competitive can be undertaken using quite a simple spreadsheet model to calculate the ceiling price for DSR relative to the price of the lowest cost reinforcement scheme.

The following example is to calculate the ceiling price for DSR to address the forecast occasional load in excess of the firm capacity of a primary substation.

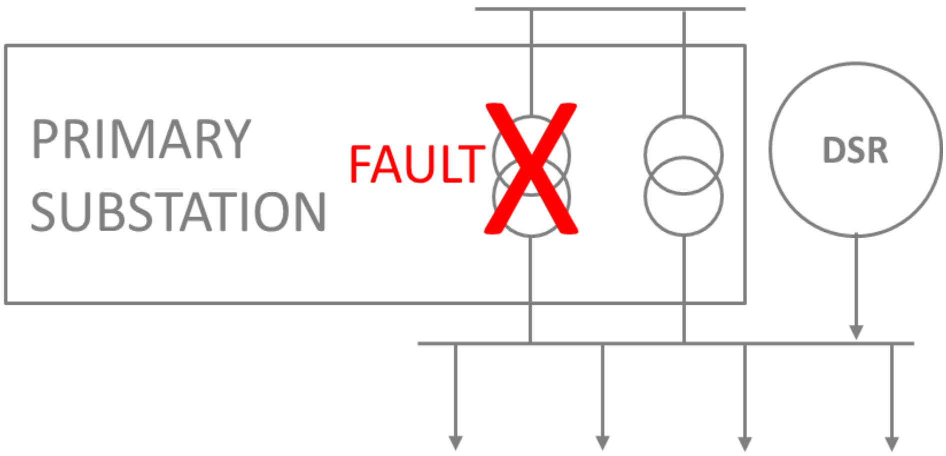


Figure 3.2: DSR used to maintain the firm capacity of a primary substation under n-1 fault situations

The steps, with some simplifying assumptions are broadly as follows:

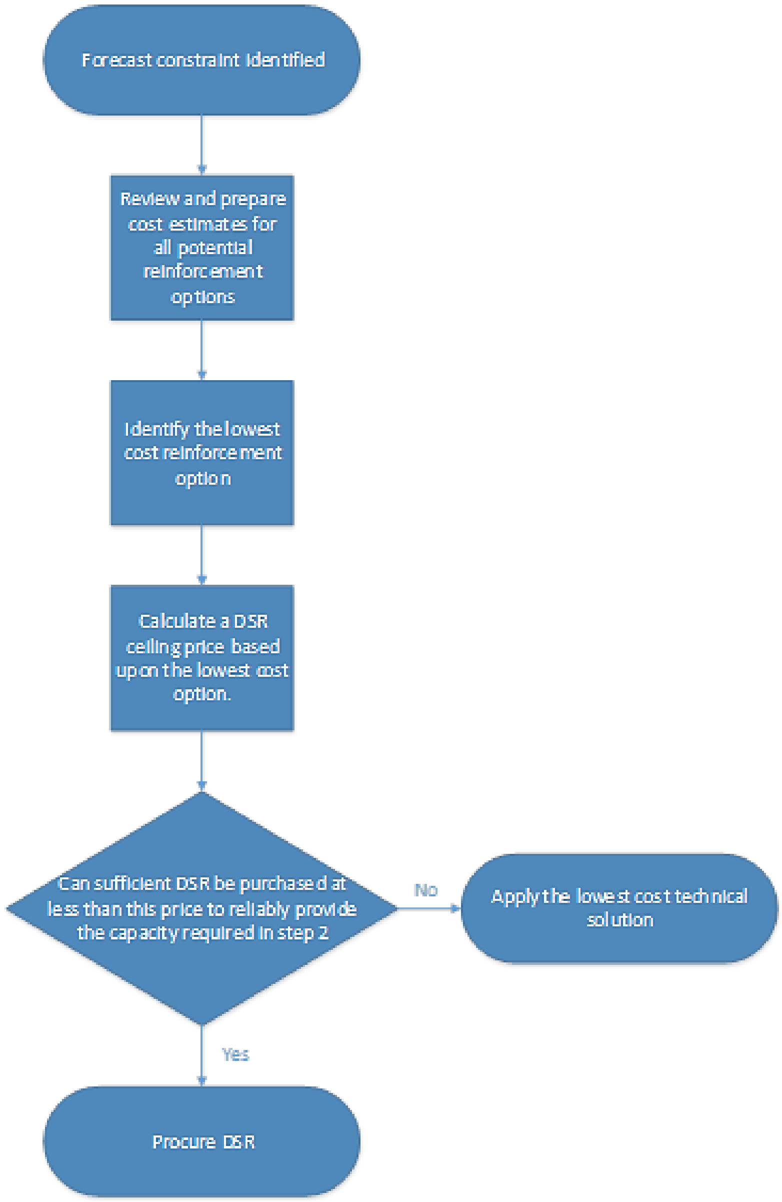


Figure 3.3 DSR assessment process

The following steps focus on specifying the DSR requirement and calculating a ceiling price.

3.4.4.1 Forecast the constraint and calculate the DSR service required

The annual review of primary substation load forecasts will provide an assessment of the future peak load profile growth to give an indication of:

- The timescales over which the firm capacity will be reached (after taking into account the transfer capacity of adjacent networks and the security contribution from generation) by which time either the DSR needs to be operational or the network reinforcement needs to have been completed.
- The timescales over which the network reinforcement can be reasonably deferred by DSR, based upon the MVA over firm that would be considered acceptable before network

intervention was required. For this example we assume this to be 2MVA and that this will be reached in five years at the forecast growth rate.

- The length of time that the load would need to remain reduced once called, which is given by the number of hours that the substation would remain over-firm after the loss of a transformer on a peak load day. For this example let's say four hours.
- The number of days over which the DSR resource is required to be available (i.e. the availability window), which is the number of days that the substation could be over-firm, which is estimated to be all of the 83 weekdays between November and February.

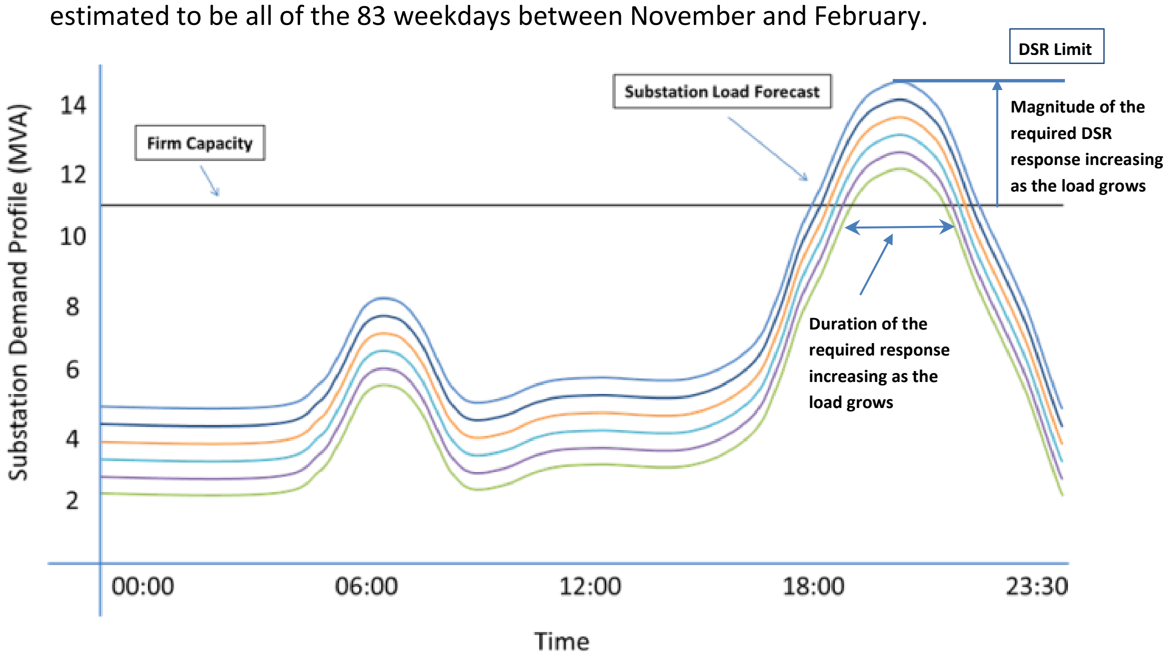


Figure 3.2: DSR used to maintain the firm capacity of a primary substation during the evening peak

A review of fault statistics will inform the number of times the service is likely to be called on average. It is estimated that this will be an average of 2 times per year but noting that some years it could be zero and some years it could be 10 or more. In summary, the DSR service required is:

- 2MVA
- for 4 hours per call
- for approximately 2 occasions per year
- available in all of the 83 weekdays between November and February.

For simplicity it is assumed that this service is needed from year 1 and that it will last for five years at which time, if the forecast rate of load growth is maintained, there will be a need to reinforce the substation.

3.4.4.2 Assess the lowest cost network option

It is assumed that lower cost options such as load transfers have been utilised and that the next lowest cost option is to replace the transformers at the substation for the next standard size at a cost of, say, £1.5m including civil and ancillary works. This would increase the firm capacity of the substation by 6MVA when, over the next 5 years, although it has been forecast that only 2MVA is required. A DSR alternative might therefore provide the DNO with the option value of not having to commit to increase capacity by the additional 4MVA and to defer this investment until there is more certain about the trajectory of the projected load growth.

3.4.4.3 Calculate the set up costs of the DSR solution

In this example it is estimated that the site-specific cost to set up a DSR control system, draw up contracts, set up payment arrangements will be in the region of £0.1m per primary substation. This would include a controller in the substation linked to a real-time thermal ratings device to monitor the transformers. It would hold details of the DSR contracts and automatically call off the DSR requirements via signals directly to the contracted provider, which could be the end provider or an aggregator.

3.4.4.4 Calculate the NPV of the DSR solution relative to the reinforcement solution.

Using a regulatory discount rate of, say 4%, it can be derived that the annual benefit of deferral which, in this example works out to be £49,000 per annum for a 5 year deferral, as shown in Table 3.2.

3.4.4.5 Calculate the MVA value of DSR contracts required based upon the reliability of response

If a reliability of 75% is assumed, then the minimum capacity needed to meet a 2MVA requirements is 2.00/0.75 = 2.67MVA.

In practice, determining the reliability factor could be a difficult calculation and will be an iterative process based upon the types of providers identified as having potential, further refined based upon those that are found to be interested, further refined by the number and duration of interruptions to which each is willing to commit.

3.4.4.6 Calculate the DSR ceiling price based upon the annual benefit of deferral, adjusted to take into account annual operating costs and reliability of response.

If an annual operating cost of 5% of the annual benefit of deferral and a reliability of 75% is assumed, then the ceiling price of DSR in this example can be calculated to be:

£49,000 * 0.95 * 0.75 = £34,912 per annum.

Dividing by the capacity required (i.e. 2MVA) gives a ceiling price of £17.5k per MVA per annum.

Dividing by the availability window (83 days) gives a ceiling price of £211/MW-day or by the 8hrs/yr. typical utilisation to give a ceiling price of £2,190/MWh.

This is the maximum value that the DNO should pay and, in this example, is assumed to deliver all the value of the DSR to the DSR providers. However, it could still be worth paying this price because of the option benefit it delivers if the future load turns out to different to the assumed forecast load.

If a lower price could be achieved, for instance by sharing the costs with other participants, then more value could be delivered to other connected customers in the form of lower future DUoS charges.

Table 3.2 shows the annotated calculation spreadsheet.

Calculating the DSR ceiling price relative to the lowest cost investment alternative

Discount rate	4%
Investment to be deferred (£m)	1.5
DSR contract period (yrs)	5
MW demand reduction required to defer investment through DSR contract period (MW)	2.00
Set-up costs (£m)	0.10
Ongoing operating costs	5%
Confidence	75%
DSR availabilty window (days/yr)	83

Regulatory discount rate

Cost of the lowest cost alternative solution

Number of years that the investment can be deferred based upon forecast load growth rates

The amount of demand reduction required to defer that investment by five years

The fixed costs of providing a DSR controller at the relevant substation plus the work required to find DSR providers, draw up contracts, and set up payment arrangements.

Reliability of DSR (Used to calculate how much DSR would need to be purchased in order to deliver the capacity required.

Availability window. i.e the number of weekdays during the period of peak loading (i.e. thereare 83 weekdays between November and February)

yr	0	1	2	3	4	5	6	7	8	9
Main investment (deferred) - £m	0.00	0.00	0.00	0.00	0.00	-1.50	0.00	0.00	0.00	0.00
DSR set-up costs - £m	-0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net cashflows (exc ongoing operating costs) - £m	-0.10	0.00	0.00	0.00	0.00	-1.50	0.00	0.00	0.00	0.00
Annual value of deferred investment - £m	**0.00**	**-0.049**	**-0.049**	**-0.049**	**-0.049**	**-0.049**	**0.000**	**0.000**	**0.000**	**0.000**

Value of deferring the capex by x years after taking into account the DSR setup costs

DSR ceiling (£k/MW-year)	**£ 17.5 k**
DSR ceiling (£/MW-day)	**£ 211**
or (£k/MWh)	**£ 2.18 k**
MW required to be contracted	**2.67**

Equals the Value of deferred investment a) reduced by 5% to allow for ongoing operating costs, b) multiplied by the reliability to reflect the overpurchase requirements and c) divided by the capacity required to give a £/MW.

Divide Rate/MW/yr by the days in the availability window to give a ceiling for the rate per day

or divide by the hours per year to give a rate per MWh contracted

This is equal to the actual DSR requirement divided by the confidence factor

Table 3.2: DSR cost benefit analysis

3.4.5 Variable sensitivity

An important sensitivity in the above calculation is related to the set-up costs, which have a high impact on the ceiling price the lower the number of years deferral as shown in figure 3.2 below.

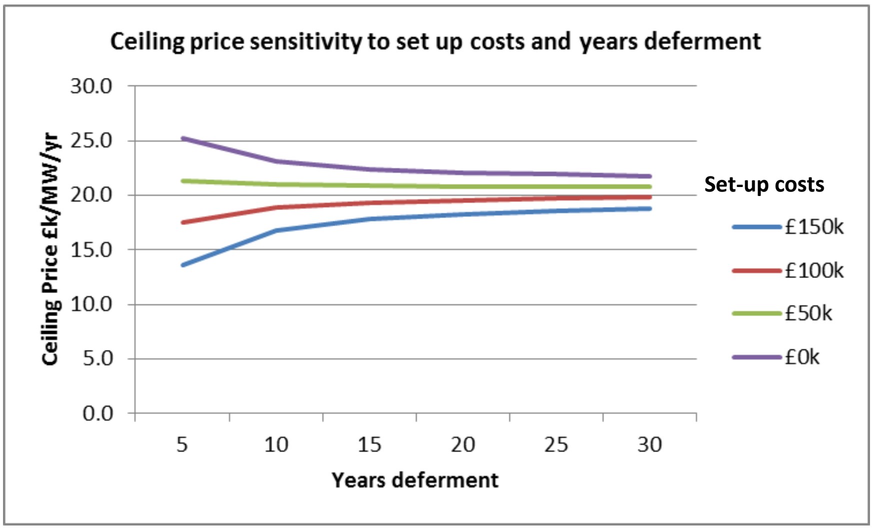


Figure 3.3: DSR price sensitivity to set-up cost and years of deferment for a £1.5m reinforcement scheme

If one could be sure of the number of years of deferment, or even if reinforcement could be avoided altogether, it may be possible in this example to consider a ceiling price in the region of £20k/MW/yr.

3.4.6 Market testing

The DSR solution will only be effective if:

- there is sufficient flexible load downstream of the network constraint to deliver a reliable response; and
- the DSR providers are willing to accept £17.5k/MW/year.

The next step, therefore, before a decision can be made on whether to pursue the I&C DSR option for this particular example, is to go to market to test these two key parameters.

If the required firm capacity can be found with an average price below this ceiling price then the DSR solution should be chosen, otherwise network reinforcement will be required.

Section 6 of this report provides details of the CLNR experience relating to customer recruitment, pricing and contractual arrangements, in which a couple of options on the CLNR project were trialled.

- **Availability & Utilisation** - A STOR type arrangement with an availability payment of £10/MW/h for each day of the availability window and a utilisation payment of £300/MW/h for each hour that the DSR response was provided; and

- **Daily charge** - A simple arrangement paid at £306/MW/h for each day of the availability window which was calculated to pay these daily charge participants the same as that paid to the participants on availability and utilisation.

The chart below chart below shows that, for a trial, the two arrangements pay the same for 10 events (as designed) at which point all providers would get the £13.8k/MW.

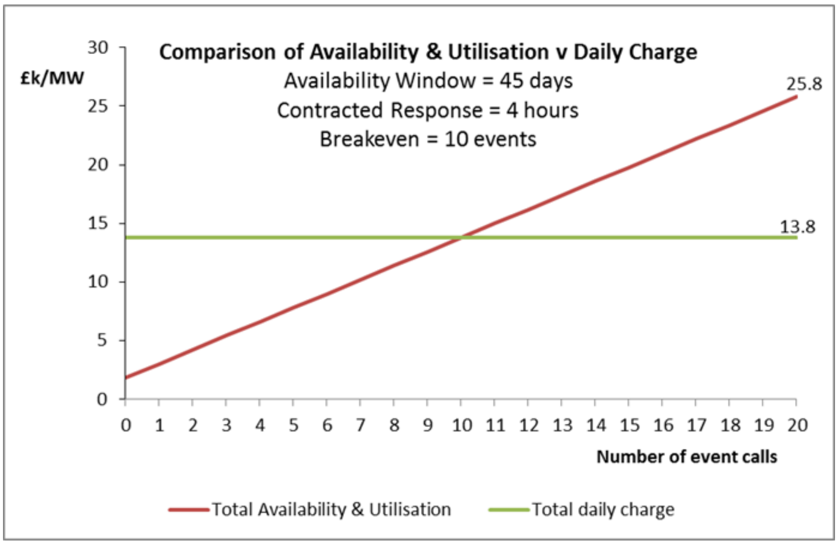


Figure 3.4: Comparison of Availability & Utilisation v Daily Charge for 2014 CLNR Trials

It was found that the trial participants were happy to participate at this price level for 10 events.

However, if a real life scheme is to be designed with an 83-day window that has the potential for the number of calls to vary between zero events and 10 events per annum, with a likely average of two, there is a decision to be made on which of these arrangements would be preferable from both a DNO and a DSR provider point of view. Table 3.3 below gives an overview of the pros and cons of each arrangement.

Contract Type	DNO Perspective		DSR Provider Perspective	
	Pros	Cons	Pros	Cons
Availability & Utilisation	Lower cost (if not called as often as predicted)	More complicated to operate and validate	Pays more if utilised more	Only the availability payment is guaranteed
Daily Charge	Costs are fixed	Higher cost option (if not called as often as predicted)	Predictability. Guaranteed income to cover costs	No additional revenue if called more than the base case

Table 3.3: Comparison of payment types from DNO and DSR provider perspective

Our discussions with providers and aggregators told us that they are looking for a predictable and bankable business cases with guaranteed returns from their investment made in the required metering, controls, management time, operation / admin time and also changes to business practices and processes if they are offering a load reduction.

DNOs need to consider whether to treat DSR payments like an insurance premium and go with the fixed price certainty of the daily charge or whether to offer to share some risk and the potential for additional reward with the DSR provider by operating a Utilisation and Availability arrangement with the potential to earn / cost each party more / less depending upon the split between availability and utilisation payments, the break-even point chosen and the number of faults actually experienced during peak load days.

If the DNO offers the Daily Charge arrangement there is certainty for everybody i.e. if the DNO pays the same amount each year whatever happens to load growth and the occurrence of faults.

However, if the DNO and DSR provider want to share some of the risk and/or potential for reward this can be achieved from the Availability and Utilisation payment method as shown in Figure 3.5 below, where the breakeven point is agreed to be six event calls and the balance between Availability and Utilisation payments can be flexed.

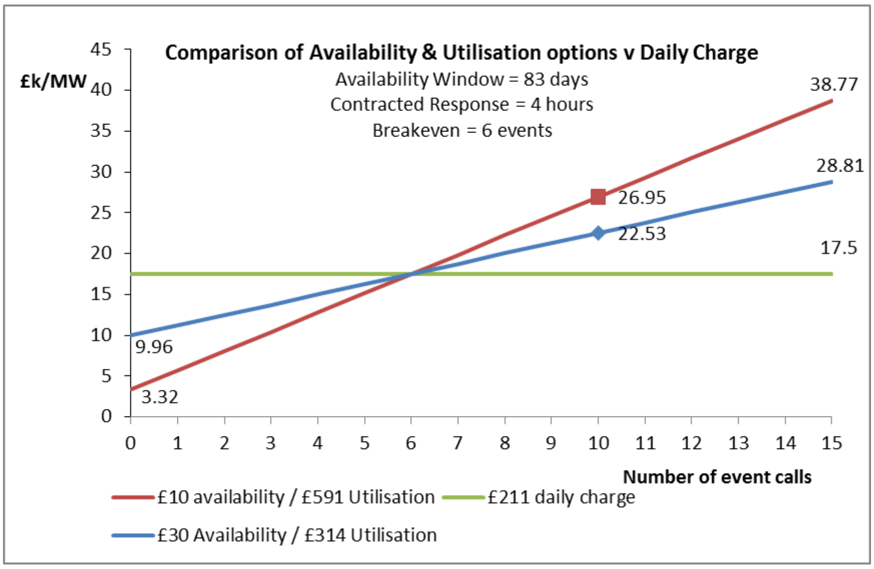


Figure 3.5 Comparison of Availability & Utilisation options v Daily Charge

This example, compares:

1. A Daily Charge of £211 MW/h which pays out £17.5k per annum guaranteed with no difference in the level of payments if more calls are made;

2. A £10/MW/h Availability and £591/MW/h Utilisation that pays out:
    a. £17.5k/MW for the agreed breakeven event call rate of 6;
    b. £3.3k/MW for a zero call rate;
    c. £26.9k/MW for 10 calls; and
    d. £38.8k/MW for 15 calls;

3. A £30/MW/h Availability and £314/MW/h Utilisation that pays out:
    a. £17.5k/MW for the agreed breakeven event call rate of 6;
    b. £9.95k/MW for a zero call rate;

c. £22.5k/MW for 10 calls; and
d. £28.8k/MW for 15 calls.

In summary, the DNO sets the ceiling based upon the reinforcement costs that are being avoided, goes out to market to see what price can be achieved and then negotiates with the bidders to agree a payment structure that best suits all parties. There is clearly scope for further work to find the correct balance which may change over time as the DNO and the DSR provider gain more experience with the arrangements.

3.5 Commercial / regulatory considerations

There are no major commercial and regulatory barriers to the implementation of on-demand I&C DSR by DNOs but the transition to the use of DSR as a business as usual solution would be assisted by a few changes, as follows:

- A review of Security of Supply standards:
  - Engineering Recommendation P2/6 Security of Supply;
  - A review of ETR 130 Application guide for assessing the capacity of networks containing distributed generation;
- Limited access to DSR resources that are locked into arrangements with other users, (for instance with National Grid's STOR arrangements);
- The establishment of better customer information to assist with customer engagement and recruitment.

3.5.1 Security of supply

A review of P2/6 'Security of Supply', with recommendations to update ENA-ETR130, was completed as part of the Capacity to Customers (C2C) project undertaken by Electricity North West. These recommendations have been fed into a more structural review of P2 by the Distribution Code Review Panel which is intended to reassess the underlying basis of network security assessments and which is still ongoing but the amendment to ETR130 have recently been made to allow the security of supply analysis to now take into account DSR. It is up to the DNO to determine the relevant reliability factors (F factors) to ensure security of supply can be maintained when DSR services are implemented to provide firm capacity and a review of all DSR trials, when completed, would be useful to inform these calculations.

3.5.2 Access to DSR shared resources

For the CLNR trials, we accessed DSR providers that were already participating in STOR but this arrangement required them to drop out of STOR for the duration of the trials. To facilitate the increased use of DSR by DNOs it would therefore be useful for more parties to share the same resource where this is technically and commercially viable. Section 3.6 provides a view of how such arrangements can develop over time.

3.5.3 Improving customer information

A key finding from the CLNR research is the difficulty in contacting I&C customers at particular network locations and, in particular, locating an appropriate person with the authority to engage in discussions on the provision of demand side response services. This could be addressed in a number of ways but a simple solution to give a helpful kick start to this engagement process would, data protection rules permitting, be for DNOs to have access to customer contact details for the half-hourly MPANs held by Suppliers.

The Master Registration Agreement (MRA) MAP 22 was published on 1 September 2014; the Agreed Procedure for the update of Customer Information across Market Participants, with the specific aim of providing customer contact details before Winter 2014 to enable DNOs to contact customers following a power outage.

The scope of the procedure is limited to passing of the following customer information from Suppliers to Distribution Businesses:

- Date and Timestamp of extract;
- MPAN;
- Full Customer Name;
- Up to four E-mail addresses (subject to a supplier risk assessment);
- Up to four customer telephone numbers.

It would be useful if the DNO could use this information to contact industrial and commercial customers to engage in discussions regarding the provision of demand side response services but there is currently a strict rule regarding the use of this information as follows:

> Distribution businesses will only use this customer information to contact the customer concerning disruptive events impacting that customer's connection to the network. This does not include for marketing purposes.

We therefore recommend that the restriction of the use of this information be relaxed for the contact details of half-hourly metered customers.

3.6 The development of commercial frameworks

Various forms of DSR are already being used. There is however, a high degree of uncertainty regarding how the use of DSR will develop, especially beyond RIIO-ED2. This will be impacted by the uptake of novel DSR propositions and wider changes in the electricity industry. The European Energy Efficiency Directive also states the need to shift policy focus from the potential of technology to actually meeting consumer needs, and specifically highlights treatment of demand response providers (and aggregators) by TSOs and DNOs in a non-discriminatory manner.

The business models for the deployment of DSR may therefore look quite different to today's models in the medium to long term. The current situation is characterised as "tariffs and bilateral contracts", this could develop in the near term (within RIIO-ED1) into a "rules based framework" which extends current practices with multilateral industry agreements for greater coordination.

Beyond RIIO-ED2 and with larger scale uptake of DSR and greater variation of providers and users of DSR, other frameworks could be developed that support more efficient use of these resources. Two options for future frameworks are "Distribution System Operator" and "Central Flexibility Market".

The three models considered by the EC smart grid task force[7], are also represented within these over-arching commercial models. These models should ensure that consumers and market participants have the necessary information and tools to adequately and effectively engage in the market. They should also limit barriers, and provide equal access for different parties and new entrants, and be flexible enough to adapt to an evolving market.

For each of these models, their impact on stakeholders and how they enable alignment of drivers of different stakeholders are reviewed. These models are illustrative in nature, and are proposed to provide an overview of the range of possible options, and their relative merits. Within these overarching commercial models the various DSR types – static, dynamic and on-demand – could be deployed.

A summary of these four commercial frameworks is provided in Table 3.3. The table reviews the main aspects and characteristics for each of the frameworks. For each of the four frameworks the key barriers, commercial risks and corresponding market scenario are summarised in Table 3.4.

Model	Key points	Characteristics
Tariffs and bilateral contracts	▪ Evolution of current practices ▪ Specific changes to support uptake of DSR (especially bid sizes and guarantee times)	Tariffs: ▪ DNO sets DUoS to incentivise peak reduction ▪ Supplier responsible to incorporate potential additional value streams in tariffs ▪ DNO has no operational control, and no guarantee of capacity Services: ▪ DNO procures peak reduction on a service basis ▪ DSR provider is responsible for capturing multiple revenue streams

[7] DSO, third party market facilitator, and data access point manager

Model	Key points	Characteristics
Rules based framework	▪ TSO, DNOs, and possibly suppliers have access to a common pool of DSR resources, with common rules (as in the proposed ENA shared services framework)	▪ Sharing pathway when needs are compatible ▪ Alignment pathway determining priority access when needs are mutually exclusive ▪ Limited flexibility to incorporate many different parties and propositions
Distribution System Operator (DSO)	▪ DNO acquires devolved local balancing responsibilities (i.e. takes on DSO responsibilities)	▪ DSO optimises local DSR for distribution and wider system benefits ▪ DNO commercial risk depends on incentive scheme design ▪ DNO centered approach, while DNOs are not necessarily the stakeholder that captures most benefit from DSR. Should not limit access to DSR for other stakeholder
Central flexibility market	▪ Providers make DSR resources available on a market platform ▪ DSR users procure from central place	▪ Could take into account external impacts on other parties ▪ Significant price risk for DNO

Table 3.3 Summary of commercial framework key points

	Tariffs and bilateral contracts	Rules based framework	Distribution System Operator (DSO)	Central flexibility market
Barriers	Limited ability for DSR providers to deliver to different stakeholders	limited barriers – development relies on industry collaboration	Significant regulatory changes to role of DNO and TSO	Extensive market and potential regulatory changes required
Commercial risks	Low commercial risk for DNOs	Low commercial risk for DNOs	DNO commercial risk depends on incentive scheme design	Market price exposure for DNOs
Market scenarios and overall efficiency	Potentially complex contractual arrangements for DSR providers offering multiple services Most limited in potential to optimise across different use cases	More challenging when many parties are involved and DSR needs are dynamic and drivers diverge	DSO role could evolve with increasing uptake of Low Carbon Technologies and Distributed generation at the distribution network level	Specifically suited with large uptake of DSR and when there are significant needs for flexibility from distributed sources at all system levels

Table 3.4 Summary of commercial framework assessment

3.6.1 Tariffs and bilateral contracts

The Business As Usual model represents potential gradual evolution of current practices. In tariff type propositions the DNO incentivises DSR providers to reduce peak demand through DUoS charges. Additional benefits to suppliers or TSO could be rolled up in tariffs, as long as the drivers for the different stakeholder use cases (e.g. local network demand peak, system price peak) are aligned. For service based DSR provision contractual conditions could be adapted to better enable DSR providers to participate, for instance lower minimum capacity requirements and less exclusive conditions. The responsibility to capture multiple revenue streams rests with the DSR provider. Third parties, such as aggregators or suppliers could support this by contracting a range of DSR resources and guaranteeing various service conditions, based on an aggregated portfolio.

The relations between the various stakeholders in the tariffs and bilateral contracts framework are depicted in Figure 3.6. Procurement of DSR resources is carried out individually and network operator signals for day-in-day-out DSR are passed on to customer through suppliers. Alternatives for procurement of DSR are available also for network operators, especially for on demand DSR from I&C customers, but transaction costs are relatively high.

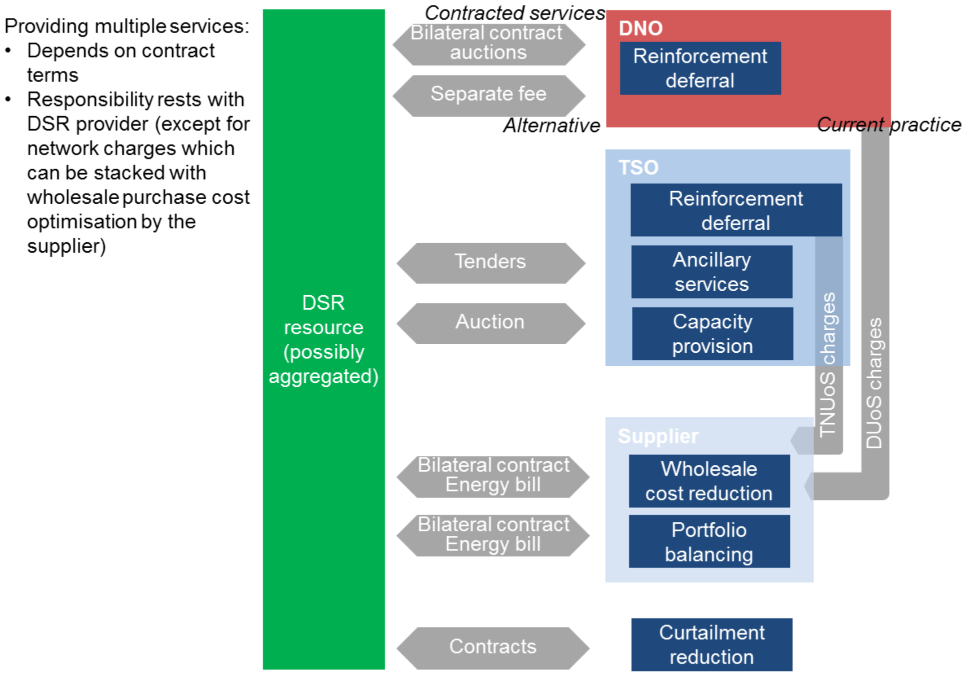


Figure 3.6 Schematic overview of tariff and bilateral contract framework

3.6.3 Rules based framework

One approach to capturing multiple value streams is with a coordinated industry rules based approach. This provides joint access of DSR resources by different parties, providing procedures for procurement and utilisation of DSR services from the same DSR provider, building on current regulatory arrangements. The framework needs to address which use cases are compatible for sharing and bilateral contractual conditions need to enable sharing between different stakeholders.

Northern Powergrid is an active member of the ENA DSR shared services group, which is a subgroup of the Energy Networks & Future Group (ENFG) that concentrates on DSR from a networks perspective, and is seeking ways for more than one network party (Network Operator and System Operator) to access the same DSR service provider.

The aim of developing this Network DSR Shared Service Framework is to establish a set of contractual rules and processes to facilitate multiple electricity network operators being able to utilise DSR from the same providers.

The ENA shared service concept paper provides a framework for DSR sharing between TSO and DNO with two distinct "pathways", based on two key elements:

- When notification of the DSR service requirement is declared.
- Which party receives the benefit from the DSR when utilised.

The alignment path captures the arrangements when a DSR action benefits only one party, or requires sole use. Procedures are defined that determine hierarchy of priority for accessing DSR resources. Priority access is given for usage of DSR to limit network peak loading, as deferral of reinforcements relies on guaranteed DSR capacity being available. In this pathway a DSR provider can potentially benefit by providing DSR services to different parties, except for when their needs are simultaneous.

The asset sharing path describes the case in which all parties can benefit from calling the DSR resource at the same time with no detriment to the other parties. In case different DSR uses are complementary, an asset sharing path is proposed. An example is the SO contracting DSR for availability to provide reserve services, while the Network Operator also has an option on the DSR resource for post fault management. Neither is using the resource continuously and the likelihood that both would want to call on the DSR resource simultaneously is low.

The group is taking this forward to build on feedback from the consultation, by:

- Developing the next level of detail on how network operators can share DSR assets, including the contractual arrangements and processes
- Developing principles on how shared DSR can be utilised
- Considering, in the context of DSR for shared network purposes:
    - Unblocking contractual restrictions
    - Interactions with the customer
    - Short and longer term approaches

- Identifying options for a demonstration project.

The relations between the various stakeholders in the rules based framework are depicted in Figure 3.7. Procurement of DSR resources by network operators, especially for on-demand I&C resources is coordinated through an industry agreed process. This framework could also be extended to include suppliers. The contractual and billing relations between providers and users of DSR are similar to those in the tariffs and bilateral contracts framework, but enable lower transaction costs and increased sharing of resources.

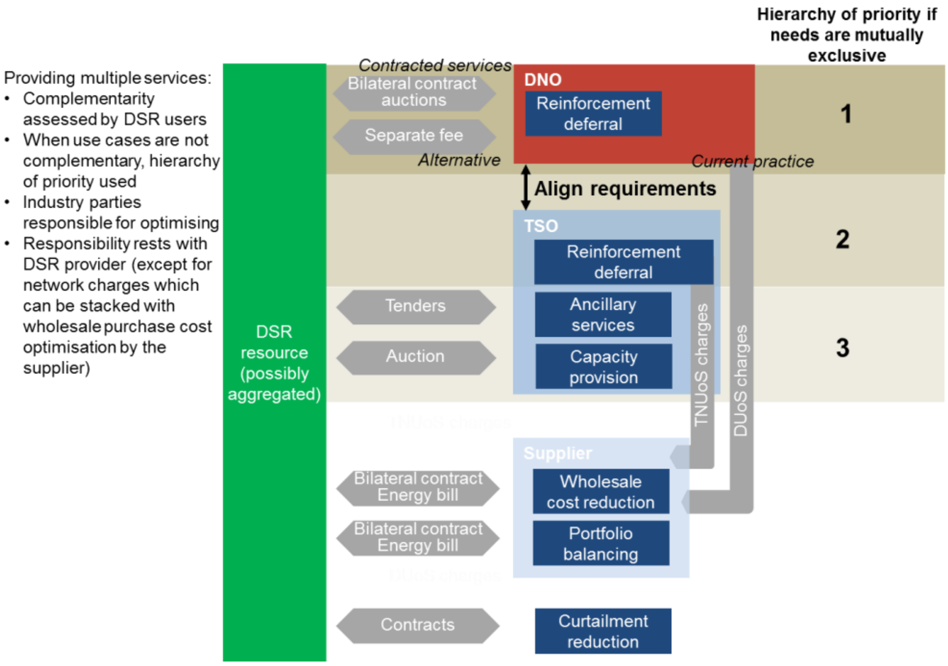


Figure 3.7 Schematic overview of rules based framework

3.6.5 Distribution system operator (DSO)

In the DSO model the DNO has devolved responsibility for local balancing and grid stability management. It represents the biggest change in the role of the DNO from managing assets to delivering electricity grid services. The DSO operates a flexible network with the ability to control load flows, and optimises local DSR resources and other sources of flexibility for distribution network and wider system benefits. To this end the DSO would procure local system services, similar to the TSO at the national level. The current regulatory framework does not provide such a market based role for DNOs, and it would constitute significant changes.

The relations between the various stakeholders if the role of DNOs develops into that of a DSO are depicted in Figure 3.8. This system is defined by the additional system responsibilities for DSOs, and access to DSR resources for different stakeholders can still be arranged in various ways. This framework may become interesting with very high or clustered uptake of intermittent generation and low carbon load technologies, similar to the drivers for the development of the current active network management areas. The DSO will have the responsibility to carry out local balancing of demand and supply, and residual system balancing will be carried out by the TSO. DSOs will be responsible for a number of local functions which could be provided by DSR and are therefore in a stronger position to procure DSR and to manage these resources across their different use cases, notwithstanding the DSR use cases for other stakeholders.

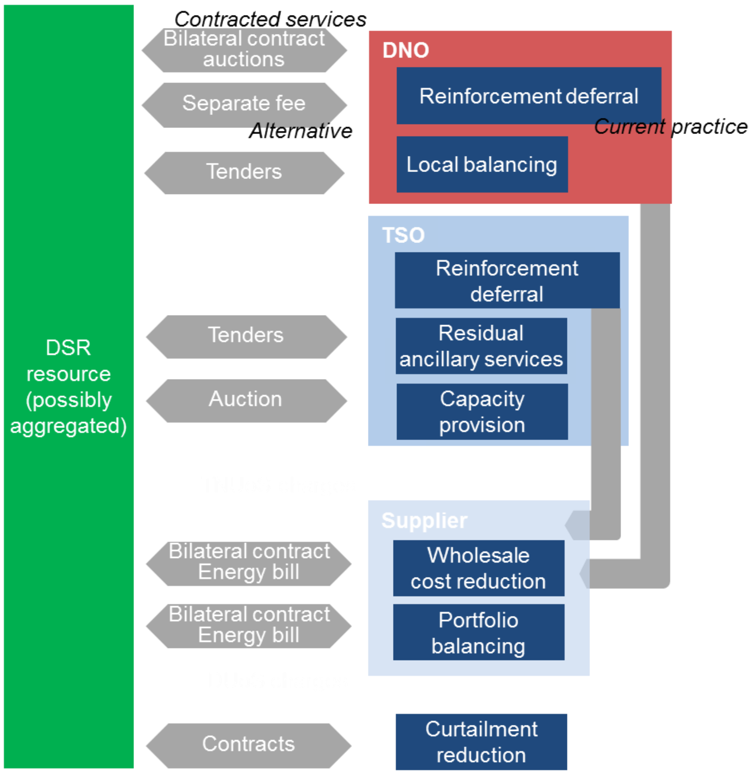


Figure 3.8 Schematic overview DSO

3.6.7 Central flexibility market

In a central flexibility market, providers would bid DSR resources into a market platform encompassing flexibility products with various characteristics, e.g. location, capacity, duration, ramp rate, response rate. Users would procure DSR resources from the market platform. This model represents the most far reaching changes in the commercial arrangements between the various stakeholders. It would allow complex interactions between a large number of stakeholders, and potentially maximise the efficient use of DSR resources. The relations between the various stakeholders in the flexibility market are summarised in Figure 3.9.

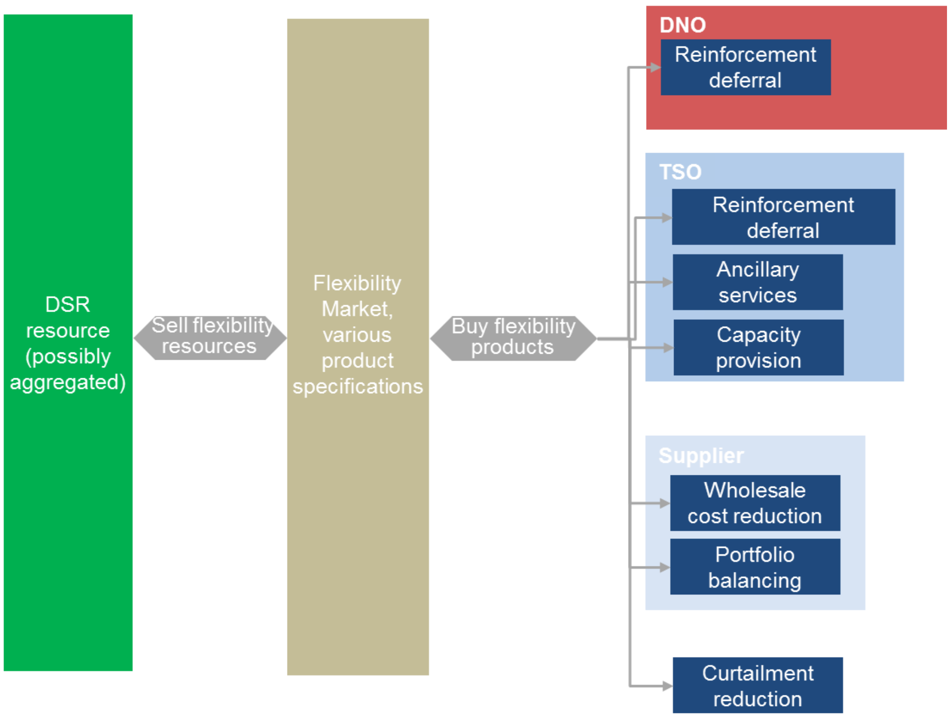


Figure 3.9 Schematic overview of a flexibility market

4 DUoS Tariff signals

4.1 Background to the April 2010 tariff review

The common distribution charging methodology (CDCM) for half-hourly metered HV and LV customers was implemented in 2010. It was developed for a number of reasons, as follows:

- To deliver benefits to suppliers (and hence customers) in terms of reduced administrative and charge forecasting costs;
- To introduce a common governance for the revised methodologies to ensure that the benefits of commonality are preserved;
- To encourage more local, low carbon generation to connect closer to demand at distribution level;
- To encourage more energy efficiency from existing customers;
- To encourage significant new loads with flexibility over where they locate to site where spare capacity already exists or away from parts of the network where it will be more expensive to connect them;
- To reward users who provide a benefit to the distribution network, for example distributed generation (DG) located close to load or for customers implementing demand side management to reduce consumption in system peak periods;
- With respect to load customers, the CDCM introduced three DUoS charging bands (Red, Amber, Green), designed to encourage the avoidance of electricity consumption in the distribution network peak periods. For Northern Powergrid, these periods are as follows:

BAND	TIME	Cost multiplier (Duos charge relative to GREEN band)	
		LV	HV
RED	16:00 to 19:30	140	190
AMBER	08:00 to 16:00 19:30 to 23:00	13	15
GREEN	00:00 to 08:00 23:00 to 00:00 (00:00 to 00:00 weekends)	1 x	1 x

Figure 4.1 CDCM time bands and relative costs

4.2 Purpose of the research

The purpose of the research was to determine whether the sharper price signals resulting from the introduction of the CDCM has had any effect on how half-hourly metered customers consume electricity throughout the day. This could be useful to inform the application of sharper tariffs to other groups and inform ancillary services contracts with individual I&C customers.

4.3 Method & results

Northern Powergrid requested Durham University to carry out a confidential review of consumption records for all its industrial & commercial half-hourly metered customers for the year before and the year after the introduction of the CDCM. Northern Powergrid has ca. 14,000 customers on this charging arrangement. It reviewed these records and passed on a subset to Durham University who then analysed the data from 1,252 of these commercial customers to compare their consumption before and after the introduction of the CDCM red/amber/green charging bands. The consumption data analysed by Durham University covered a wide range of customer types, as follows:

- Supermarkets
- Telecoms
- Banks
- High street shops
- Water companies
- Chemicals
- Plastics
- Steel
- Textiles
- Tools
- Public houses / restaurants

In addition, both suppliers and some half-hourly metered customers were interviewed to find out to what extent the structure of the CDCM charges were passed through and visible to customers in their Supplier bills.

The graph in Figure 4.2 shows that there has been very little change in the proportion of demand per time band after the implementation of the CDCM.

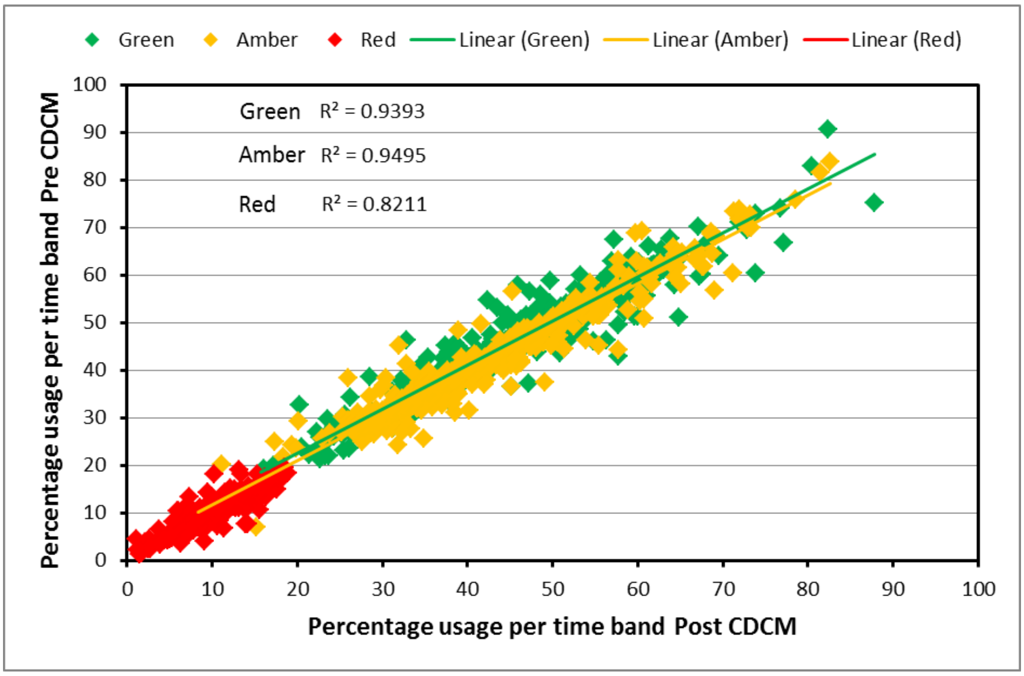


Figure 4.2: Distribution of consumption in each time band before and after the introduction of CDCM

To further analyse the impact of the CDCM, the percentage usage per time band was calculated for the chosen period before and after the DUoS reform. A typical plot of the percentage differences for customers in different sectors is shown below.

Banking sector

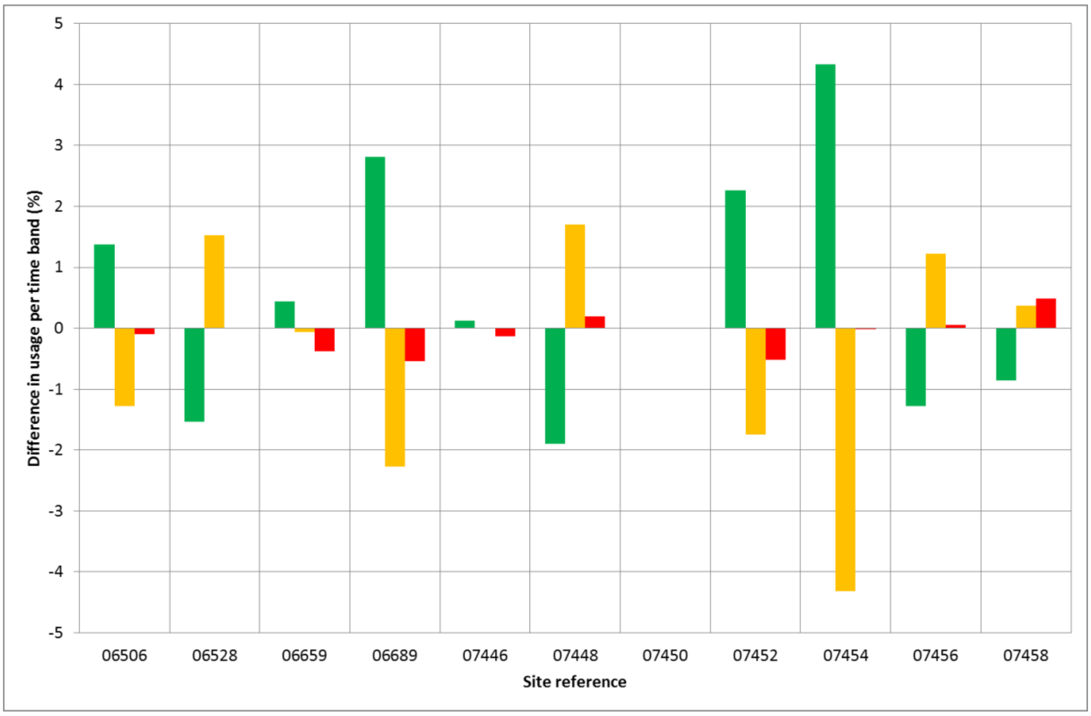


Figure 4.3 – Northeast *banking sector* typical demand shifts after CDCM introduction

Figure 4.3 shows the variability between sites in their demand shift per time band. An ideal scenario would result in a shift to the Green tariff band from the Red in order to minimise DUoS charges. The Green time period is however, limited to the hours of midnight to 8am and from 10pm to midnight Monday to Friday and all-day Saturday and Sunday.

Site Reference	Percentage Shifts		
	Green	Amber	Red
06506	1.38	-1.28	-0.10
06528	-1.53	1.53	0.00
06659	0.44	-0.06	-0.38
06689	2.82	-2.28	-0.54
07446	0.13	0.01	-0.14
07448	-1.90	1.70	0.20
07452	2.26	-1.74	-0.52
07454	4.33	-4.32	-0.01
07456	-1.28	1.23	0.06
07458	-0.85	0.36	0.49
AVERAGE	**0.58**	**-0.48**	**-0.09**
STDEV	**2.08**	**1.92**	**0.32**
SKEW	**0.54**	**-0.80**	**0.16**

Table 4.1 – Percentage shifts for Northeast *banking sector* sites

Table 4.1 shows the data plotted in Figure 4.3. The average percentage shifts for each of the time bands are lower than 1% with a maximum of +0.58% in the Green tariff period. Green and Amber values vary in both the positive and negative direction, leading to a conclusion that the take up of the new DUoS scheme has not been uniform.

Steel sector

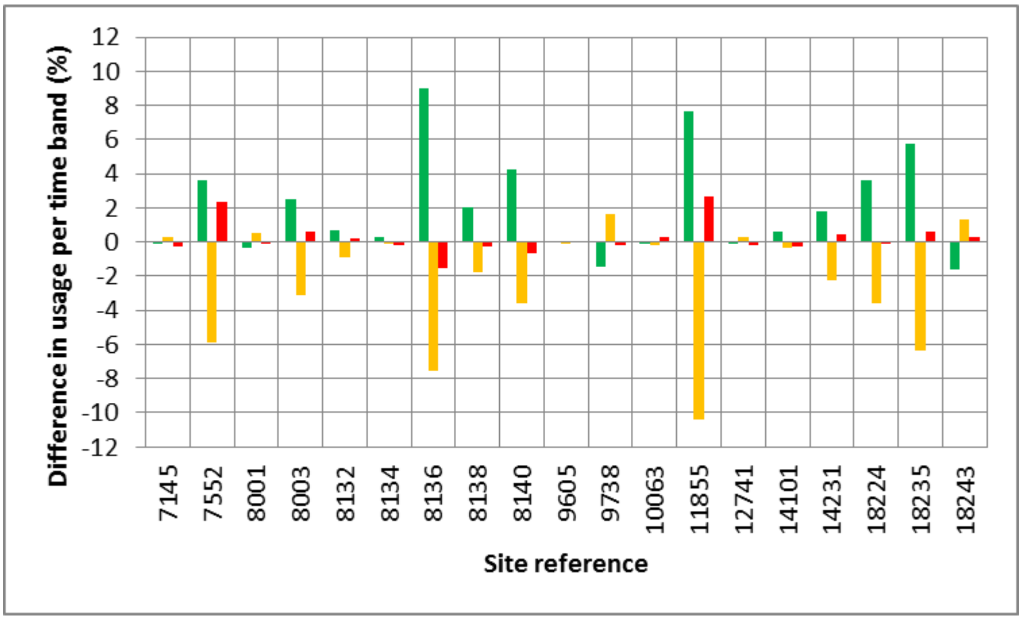


Figure 4.4 - Northeast Steel sector typical demand shifts after CDCM introduction

Figure 4.4 shows the same analysis as that in Figure 4.3 however for a number of sites in the steel sector. Clearly visible are a number of sites where there has been a greater than 5% shift to the Green tariff band. .

	Percentage Shifts		
Site	**GREEN**	**AMBER**	**RED**
07145	-0.01	0.31	-0.30
07552	3.59	-5.92	2.33
08001	-0.37	0.49	-0.12
08003	2.49	-3.10	0.61
08132	0.65	-0.90	0.25
08134	0.30	-0.12	-0.18
08136	9.04	-7.54	-1.50
08138	2.03	-1.74	-0.29
08140	4.23	-3.60	-0.63
09605	0.06	-0.14	0.07
09738	-1.48	1.62	-0.15
10063	-0.08	-0.18	0.26
11855	7.67	-10.36	2.69
12741	-0.11	0.28	-0.17
14101	0.59	-0.34	-0.24
14231	1.83	-2.27	0.44
18224	3.62	-3.61	-0.01
18235	5.73	-6.34	0.61
18243	-1.59	1.33	0.26
AVERAGE	**2.01**	**-2.22**	**0.21**
STDEV	**2.98**	**3.30**	**0.94**
SKEW	**1.06**	**-1.09**	**1.41**

Table 4.2 – Percentage shifts for Northeast Steel sector sites

Table 4.2 shows the percentage shifts for the data in Figure 4.4. The largest shift from the Red period is a reduction of 1.5%, suggesting, again that the sharper price signals have failed to incentivise customers.

Textile sector

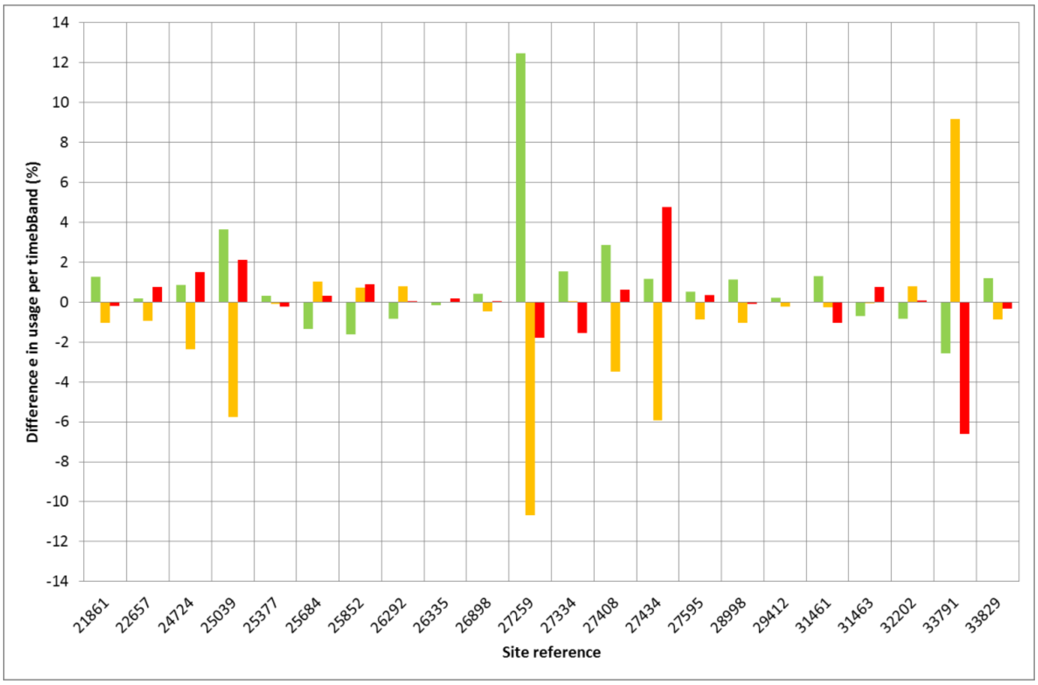


Figure 4.5 - Yorkshire Textile typical demand shifts after CDCM introduction

Figure 4.5 shows the results for textile customers in the Yorkshire area. This figure has been shown to detail that in some cases, single sites can have a large impact on the average changes per customer group (Site 27259).

Figures 4.6 and 4.7 show the summary average percentage shifts across a wider range of sectors for both the Northeast and Yorkshire DNO areas. Whilst Figure 4.7 suggests that in the Yorkshire area, the percentage shifts to the Green period have been more common, it must be noted that the maximum average percentage shift is 1.48%. In the Northeast area the maximum average shift (in the Tool category) was 2.84%.

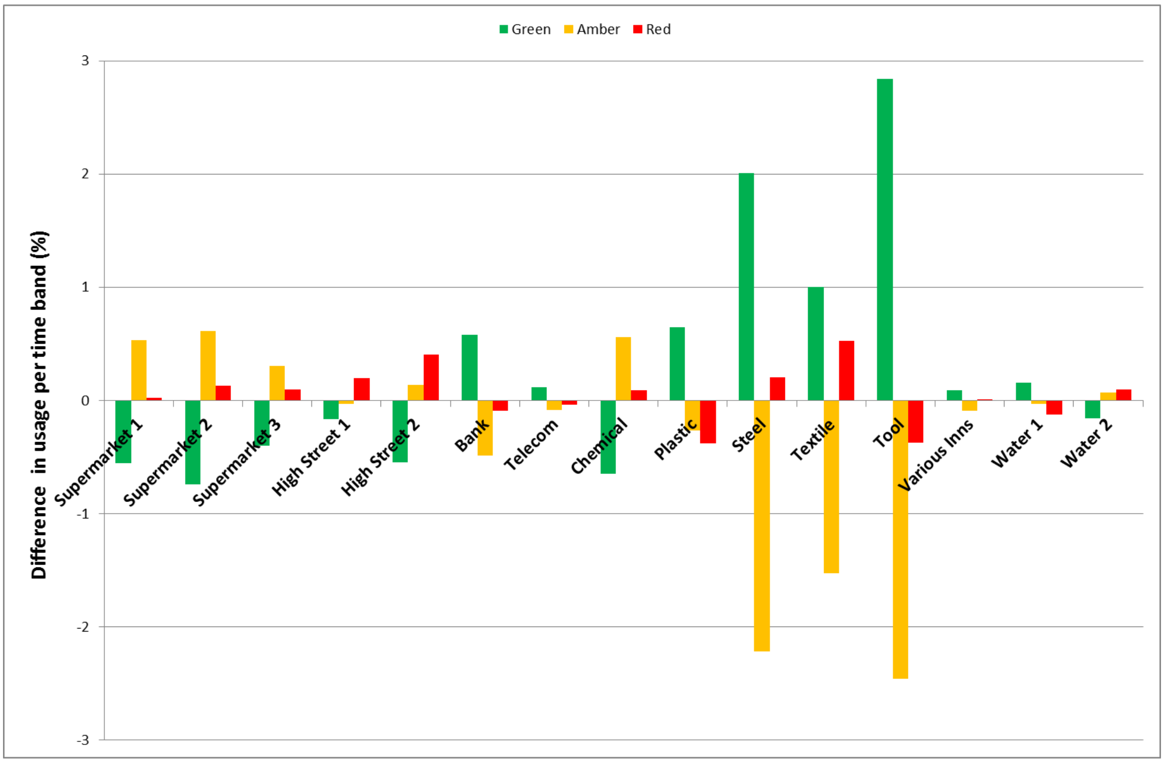


Figure 4.6 – Average Percentage Demand Shifts Northern Powergrid (Northeast)

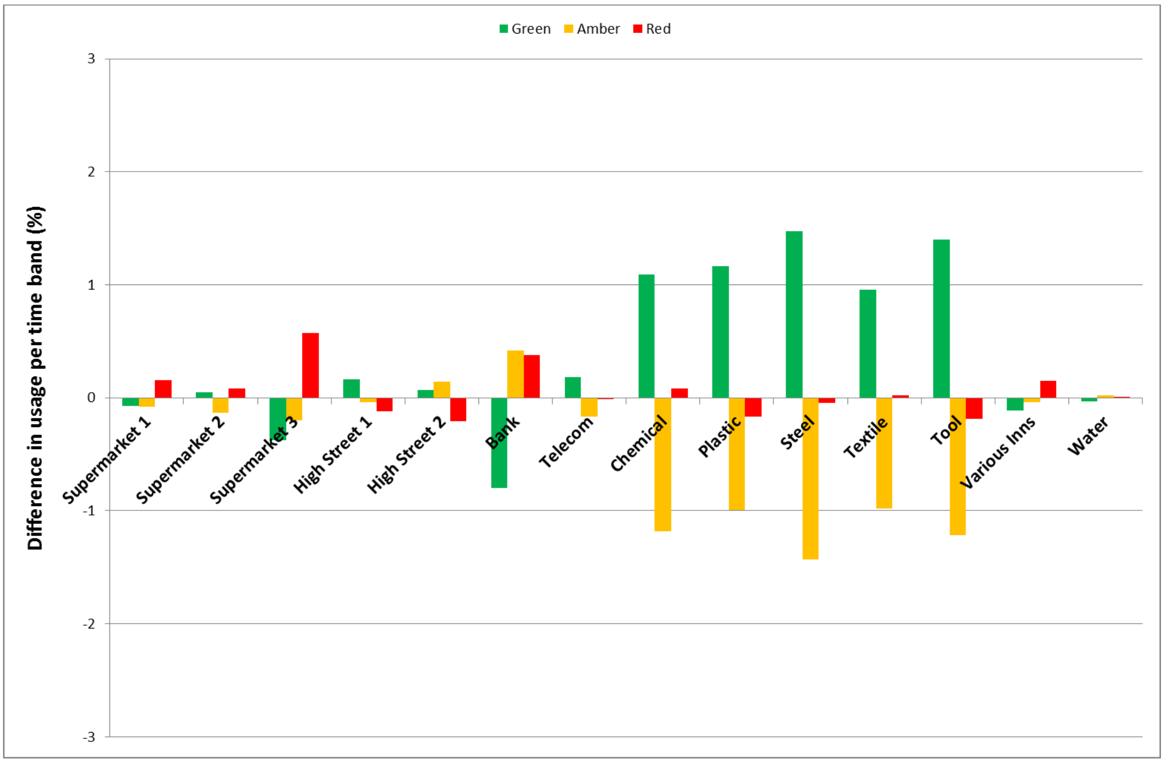


Figure 4.7 – Average Percentage Demand Shifts Northern Powergrid (Yorkshire)

Taking a higher level view, Figure 4.8 shows the average load profile across all CDCM customers a) as an average for the year and b) on the day of system peak. It clearly shows that the half-hourly metered customers profile peak does not occur in the red band.

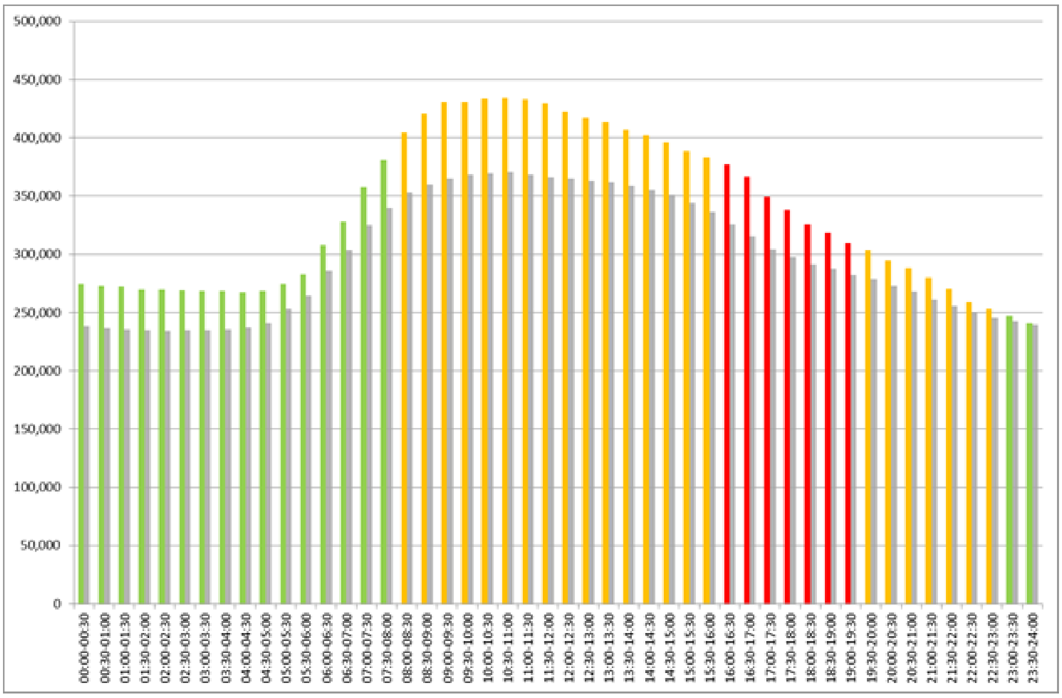


Figure 4.8: CDCM customer – Half-hourly consumption

The Grey Bars are aggregate average consumption and the coloured bars are the aggregate average consumption on the peak day.

Table 4.3 shows the average consumption in each time band over the whole year and Table 4.4 shows the average consumption in each time band on the day of system peak. Both show no discernible shift out of the red band since the introduction of the CDCM in 2010.

Year	Red	Amber	Green
2008/09	11.81%	39.10%	49.08%
2009/10	11.87%	39.46%	48.67%
2010/11	11.80%	39.22%	48.98%
2011/12	11.79%	39.07%	49.13%
2012/13	11.73%	38.99%	49.28%
2013/14	11.82%	39.14%	49.04%

Table 4.3: Percentage of Total Consumption in Each Time Band

Year	Red	Amber	Green
2008/09	15.25%	50.62%	34.13%
2009/10	15.30%	50.31%	34.38%
2010/11	15.36%	50.33%	34.31%
2011/12	15.25%	50.27%	34.48%
2012/13	15.34%	50.41%	34.25%
2013/14	14.81%	50.20%	34.99%

Table 4.4: Percentage of Total Consumption in Each Time Band on Day of System Peak

Over the last five years there has been a downward trend in annual consumption which might be due to the financial downturn, but could also be due to increasing energy efficiency, but we have not seen any evidence to suggest that significant numbers of consumers are reacting behaviourally to the price signals introduced in the CDCM in April 2010.

4.4 Results from interviews with suppliers and customers

We contacted a number of suppliers and customers to explore this further.

We issued a questionnaire to the six big suppliers and two of the smaller suppliers and received responses back from five of the seven. From these responses it is apparent that most half-hourly metered / half-hourly settled (HH) customers connected at HV or LV do ***not*** currently see the underlying time of day price signals that are sent from the DNO to the Supplier via the common distribution charging methodology (CDCM). For instance, one of the big six suppliers responded that 10% of its HH customers are on a single rate tariff, 85% on two rate tariffs and only 5% on seasonal time of day tariffs (of which 4% are on a four rate winter peak tariff and only 1% on a CDCM based tariff). However, looking at these tariffs from an energy consumption point of view, then 10% of its HH customers are on single rate tariff, 69% on two rate tariffs and 21% on seasonal time of day tariffs (of which 1% are on a four rate winter peak tariff and only 20% on a CDCM based tariff). The supplier suggested that this perhaps indicates that the more energy intensive users with the ability to load manage, such as water companies, telecoms, etc. are more inclined to require transparency of costs. However, they state that the majority of customers prefer a flat tariff to give them consistency with previous billing structures and also because it makes bill validation easier.

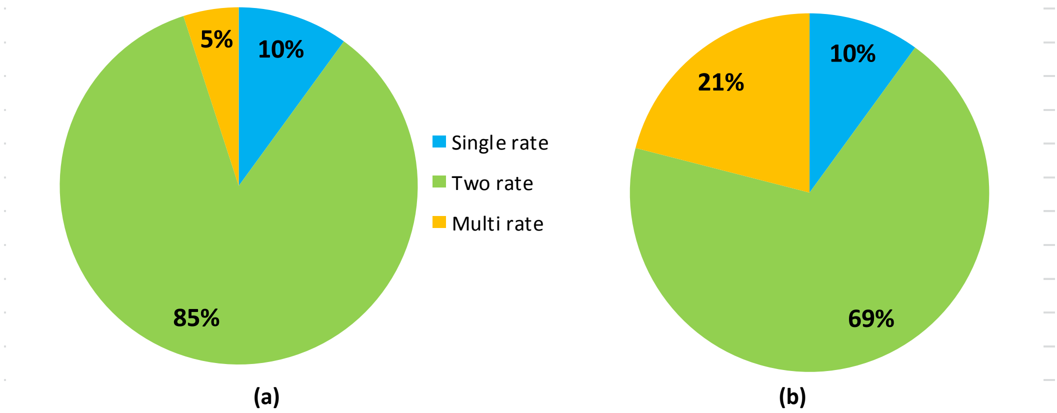


Figure 4.9 Supplier tariffs split a) by customer numbers and b) by kWh consumption

One of the smaller suppliers had a similar story to tell with only about 5% of its HH customers on multi-rate tariffs and said that the types of customers that prefer a time-of-day tariff were typically customers with energy spends in excess of £500k per annum who can justify either external contract management through a third party intermediary or have their own dedicated energy buyer. Companies that choose a flat tariff tend to be those that purchase via third party intermediaries who evaluate tender responses between suppliers. They generally require day/night rate tariffs, where DUoS and TNUoS charges are included at an estimated cost within the Electricity Prices, which helps in evaluating the tender responses between suppliers, and provides cost reflective pricing. However, it doesn't provide any signal through to end consumers to change their consumption pattern beyond general energy efficiency reduction.

A general view from Suppliers when asked whether the CDCM price bands should be visible in all HH tariffs is that this should not be a mandatory requirement saying that it is not reasonable to force more complexity on customers and that customers may want the costs fixed by suppliers to reduce volatility in their energy bill because they can't risk any volatility in their energy budget. Also if customers do not plan to undertake any demand management measures, or if they have inflexible processes, there may be no benefit in them receiving pass through charging.

The first customer we looked at was Northern Powergrid who, ironically, are currently on a flat tariff but this is because the company is on a 5 year fixed rate deal that commenced in March 2010; one month before the commencement of the CDCM. This could therefore be another explanation for the inertia in the uptake of cost reflective tariffs.

Another customer was a local authority with a portfolio of several hundred properties including council offices & depots, theatres, libraries, schools, leisure centres, libraries, bus depots, etc. This customer does see peak pricing in its electricity bills as shown below:

Charging bands		**% of day**	**% kWh**	**% £**
RED	Peak rate: 4pm – 7.30pm	15%	16%	37%
AMBER	Day rate: 8am – 4pm, 7.30pm – 10pm	44%	53%	43%
GREEN	Night rate: 10pm – 8am	42%	32%	20%

Table 4.5: Consumption in the CDCM time bands for a Local Authority

This customer is actively engaging in behavioural change programmes to identify efficiencies that will reduce overall energy consumption but has not yet initiated a programme to specifically target consumption in the red band period which, whilst it only accounts for 16% of consumption, actually accounts for 37% of its unit-related element of its bill. Such an activity is on its "To-do list", though.

Another customer with sites at HV and also at EHV has said that in all their HH contracts the DUoS element is available as a pass-through charge, and is clearly itemised on the bill. However, they say that suppliers don't appear to go out of their way to tell them about the peak pricing but think that this may be because they recognise that they are relatively well informed, due to their high unit consumption. They go on to say that their LV/HV sites, typically consume a small percentage of their total power and also that power is a lesser proportion of the site costs. In these cases, the profile of energy management is lower and few actions are taken to reduce peak consumption. However, on their EHV sites which consume 95% of their energy requirements, controlling the cost base is critical and there is a stronger cost/benefit case for avoiding the EHV EDCM[8] 'super-red' band. The resultant of all these components influences their production plans, which determines the degree of load-shifting, or even which site they choose to produce at (and therefore deliver product from).

We contacted a major supermarket chain that has its own supply licence and therefore has access to all the peak pricing signals. They see the red, amber, green of the underlying CDCM tariff and currently do actively reduce their consumption during the red period via the control of heating, ventilation and air conditioning (HVAC). They did comment, though that they have to have slightly different settings across all their stores due to the DNOs all having slightly different time bands.

[8] EDCM – Extra High Voltage Distribution Charging Methodology

Finally, we questioned our project partners, Durham University and EA Technology Ltd. Durham University was offered a multi-rate tariff option that passed through the red, amber, green price signals but chose a flat rate tariff for budget certainty. EATL is billed by its landlord for electricity and was not given a tariff option. Both organisations feature overall energy efficiency as a valued contribution to their Environmental Management Plan / Carbon Management Plan, undertaking activities like lighting replacement and, in the case of Durham University, voltage optimisation and CHP installation, but neither organisation specifically reduces demand at particular times of day in accordance with tariff pricing.

In order to capitalise on the potential for a shift of consumption from the red band to the amber / green bands we recommend that Suppliers give more transparency to the CDCM pricing bands for the DUoS element of the Suppliers' tariffs to enable I&C customers to benefit from the cost signals that they provide if they so choose.

Such a move would provide additional incentive for I&C customers to permanently reduce load during peak load periods or would deliver additional value to those that wish to provide dynamic ancillary services such as load reduction or standby generator response.

4.5 Conclusions & recommendations

The aim of this trial was to investigate the effect of the CDCM with regards to demand shifting. Figure 4.1 shows linearity in demand variations across the time periods, suggesting insensitivity to the price signals of the CDCM and therefore minimal resultant demand shifting.

If the signals were working we would expect the first reaction to be a deferral of consumption from the red period to amber. This does not seem to have occurred. Customers who have shown a more significant than average change in their usage per time band have been identified. Whilst demand shifting has been shown to occur at some sites, differences have been minimal. It is therefore most likely that this can be attributed to typical fluctuations in energy consumption on a yearly basis.

The reason for the apparent lack of movement in customer load consumption behaviours could be due to a number of reasons:

- the underlying distribution use of system (DUoS) tariff not being visible in all the Suppliers' tariff offerings;
- Customers preferences for the certainty and lack of complexity of a flat tariff;
- Customers tied in to fixed period contract; and
- the nature of the I&C load profile which does not have an evening peak and actually starts to fall away from 16:00 onwards.

From a survey of Suppliers we found that only a small percentage of customers see price signals that encourage peak avoidance and the Suppliers fed back that they would not wish to see the pass through of the DUoS pricing to be mandated.

However, in order to capitalise on the potential for a shift of consumption from the red band to the amber / green bands it is recommend that Suppliers make their customers more aware of the potential benefits of peak pricing in their retail tariffs to enable their half-hourly metered customers to benefit from the cost signals that they provide if they so choose.

Such a move would provide additional incentive for I&C customers to permanently reduce load during peak load periods or would deliver additional value to those that wish to provide dynamic ancillary services such as load shift or standby generator response.

5 Generator contribution to system security

5.1 Purpose of the research

This research used the generation profiles from CLNR to inform a review of Engineering Technical Report (ETR) 130[9] for assessing the capability of a distribution network containing distributed generation to meet demand, in order to comply with the security requirements of ER P2/6[10]. It analyses the data collected from test cell 8 related to the profiling of distributed generation in order to update the current set of F factors and to review the current methodology for assessing the contribution of distributed generation to network security. It answers two key questions:

(i) are the current set of F factors fit for purpose on the basis of the new field trial data?

(ii) is the current ETR 130 methodology for assessing the contribution of DG to network security fit for its purpose?

5.2 Method

The overall approach to the review of planning and design standards of electricity distribution networks and is illustrated in Figure 5.1.

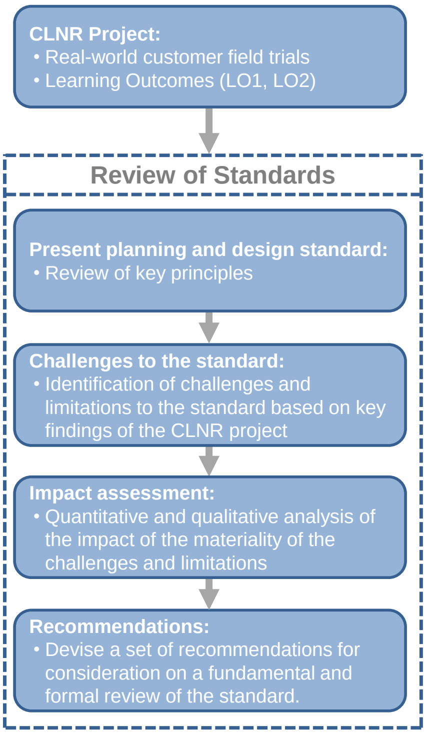


Figure 5.1: Overview of the approach

[9] ENA, 2006. "Engineering Technical Report 130, Application Guide for Assessing the Capacity of Networks Containing Distributed Generation", Energy Networks Association, Engineering Directorate, July 2006.
[10] ENA, 2006. "Engineering Recommendation P2/6, Security of Supply", Energy Networks Association, Engineering Directorate, July 2006.

For each distribution network planning and design standard under consideration, the review process is developed as follows:

- Brief introduction of the fundamental principles of the standard that are important for the development of the overall review;
- To identify and understand the challenges and limitations of the standard within a future low carbon electricity system;
- To quantify and assess the impact of the low carbon challenges in the current standard based on the Learning Outcomes and customer trial data of the CLNR project;
- To devise a set of recommendations to be considered by the Energy Networks Association (ENA) and the DNOs during a future review process of the electricity distribution network standards.

5.3 Review of ETR 130 standard

This section reviews some of the principles of the ETR 130 for assessing the capability of a network containing DG to meet demand in order to comply with the security requirements of ER P2/6. The section combines the key concepts underpinning this distribution network planning and design standard with Learning Outcomes one and two of the CLNR project to support DNOs improving the design of electricity distribution networks, ensuring techno-economic efficiency and value for money for consumers.

The section first introduces the key principles of ETR 130. It then lays out some potential limitations within a future low carbon electricity system. Subsequently, the section uses the Learning Outcomes of the CLNR project to quantify the impact of the low carbon challenges in the current planning and design standard. Finally, the section establishes a set of recommendations to be considered by DNOs in the planning and design of future electricity distribution networks.

5.4 Principles of the ETR 130 standard

ETR 130 supports Engineering Recommendation (ER) P2/6[11] by providing guidance on assessing the capability of a network containing DG to meet demand. In particular, ETR 130 specifies the network security contribution that should be credited to different forms of DG. This subsection introduces the key principles of ETR 130 that relate to the method for estimating the contribution of DG to network security.

The distribution network security standard ER P2/6 consists primarily of two tables and an approach to determine the capability of a network to meet demand.

- “Table 1” (as in ER P2/6) sets out the normal levels of security required for distribution networks classified in ranges of Group Demand. Namely, it specifies the maximum reconnection

[11] ENA, 2006. “Engineering Recommendation P2/6, Security of Supply”, Energy Networks Association, Engineering Directorate, July 2006.

times following pre-specified events leading to an interruption. This time is dependent on the group demand affected by the interruption, reducing as the group demand increases.

- "Table 2" (including "Tables 2.n" as in ER P2/6) sets out the contribution to system security expected from different types of DG connected within a demand group.
- The capability of a system to meet the group demand after first and second circuit outages should be assessed as: (i) the appropriate cyclic rating of the remaining distribution circuits which normally supply the group demand, following outage of the most critical circuit (or circuits); plus (ii) the transfer capacity which can be made available from alternative sources; plus (iii) the contribution of the DG to network capacity as specified in "Table 2", for demand groups containing DG.

Following a network circuit outage, the standard specifies the approach for assessing the expected contribution that the remaining network circuits and DG can make to security of supply as depicted in Figure 5.2.

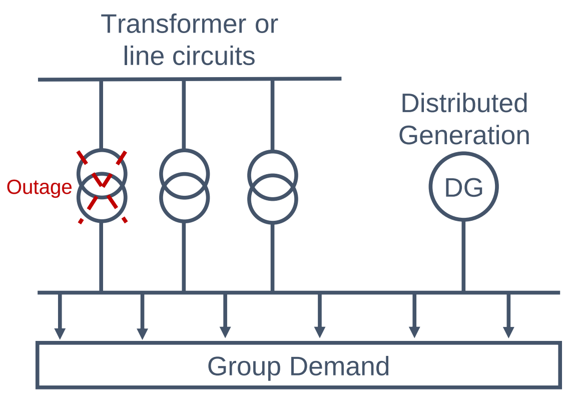


Figure 5.2: Example of a distribution system structure

The basic principle, adopted by the distribution network security standard, for assessing the contribution of DG to security of supply[12][13] is to determine the capacity of a perfect circuit that, when substituted by DG, gives the same level of reliability. The standard compares DG with the effective capacity of a perfect circuit and uses Expected Energy Not Supplied (EENS) as the reliability criterion. This principle is illustrated in Figure 5.3 below.

[12] ENA, 2006. "Engineering Technical Report 130, Application Guide for Assessing the Capacity of Networks Containing Distributed Generation", Energy Networks Association, Engineering Directorate, July 2006.
[13] N. Allan, G. Strbac, P Djapic and K. Jarret, 2002. "Security Contribution from Distributed Generation (Extension part II)", ETSU/FES Project, K/EL00287 Extension, Final Report, University of Manchester Institute of Science and Technology, 11 December 2002.

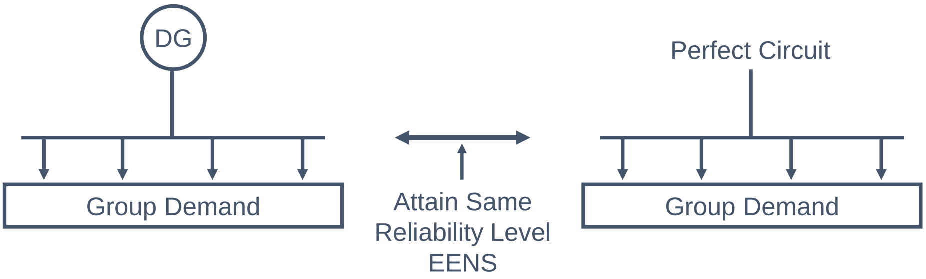


Figure 5.3: Comparison of DG with a circuit capacity

Assuming the perfect circuit is fully reliable, the comparison between DG and circuit capacity is performed by adjusting the circuit capacity until the same level of EENS is attained. Under this condition, the capacity of the perfect circuit will be lower than the peak demand. Figure 5.4 displays under the load duration curve, the magnitude of capacity of the perfect circuit and therefore the DG capability that attains the same level of EENS for the period of analysis.

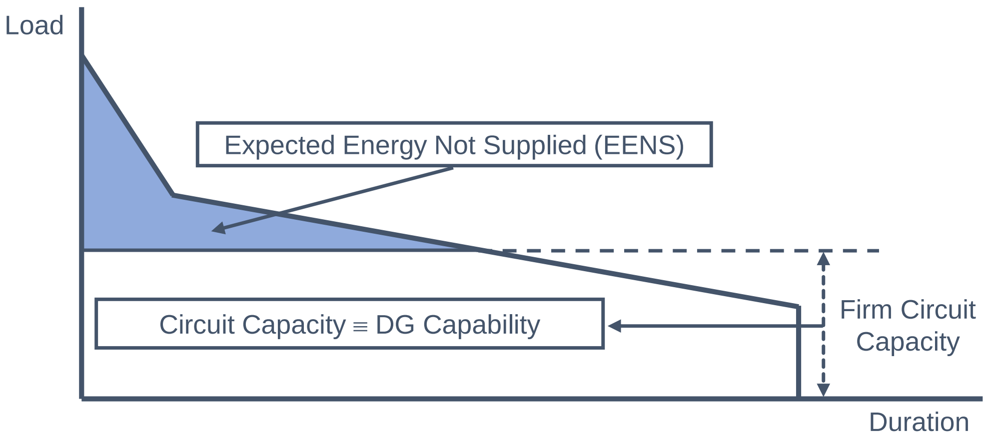


Figure 5.4: Evaluation of firm circuit capacity for a specific level of EENS

The capability of DG to meet demand is equivalent to the quantified perfect circuit capacity. It can be translated into an F factor (in percentage) through the ratio between the capability of DG and the rated capacity of DG.

- The approach followed by the ETR 130 to calculate the F factors can be summarised as follows:
- Define the capacity outage and probability table[14] (COPT) for the DG plant;
- Define the load duration curve (LDC) at a primary substation over the winter period;
- Rescale the LDC so that the peak demand equals to the installed capacity of the DG plant;
- Superimposed the COPT on to the rescaled LDC and calculate the EENS;

[14] R. Billinton, R Allan, 1996. "Reliability Evaluation of Power Systems", Second Edition, Plenun Press, New York, 1996.

- Calculate the capacity of a perfectly reliable circuit that would give the same EENS if it supplied the demand in the absence of the generation; and

- Calculate the F factor for DG as then the ratio of the perfectly reliable circuit capacity over the installed capacity of the DG plant.

The distribution network security standard ER P2/6 supplies generic F factors for a number of technologies, based on historical data available at the time the standard was developed. In cases where the available data was sparse, it is noted that there is low statistical confidence in these generic F factors as specified in the ETR 130. For cases where more detailed consideration of a particular DG unit is required, or where a technology is not included in “Table 2”, ER P2/6 notes that reference should be made to the guidance in ETR 130, including the possible use for assessing F factors of the computer package described in ETR 131[15].

For non-intermittent generation, the F factors for units of a given technology depend on the number of generation units in an installation (as for an ensemble of units having similar properties, the distribution of available capacity exhibits less variability from its mean if the number of units is larger), the size of the units and their individual long-term availability. For intermittent generation, the F factors for a technology depends only on the total installed capacity and the availability statistics for that technology. Furthermore, the F factor is reduced if the contribution of the DG is required to persist for a substantial period of time.

ETR 130 also provides general guidance on the likely technical and contractual considerations that a DNO might need to consider when looking to include the contribution for a DG plant(s) to satisfy the requirements of ER P2/6. The range of technical and contractual considerations include common mode failures, the de minimis criterion under which only DG above a certain size is included in an assessment under P2/6, and how commercial considerations may influence the predictability of output profiles.

5.5 Challenges to the ETR 130 standard

The decarbonisation of the energy sector is leading to a shift of the distributed generation and electricity demand technologies that is likely to have major implications for distribution networks as it will drive a dissimilar impact on network design and operation to that of the traditional practices. The CLNR project has contributed to the understanding of the decarbonisation impact through the development of real-world customer field trials[16] and through the learning on customer’s current, emerging and possible future load and generation technologies.

The move towards a low carbon economy prompts the need to establish how the new distributed generation and demand technologies should be treated in the planning and design of distribution

[15] ENA, 2006. “Engineering Technical Report 131, Analysis Package for Assessing Generation Security Capability – Users’ Guide”, Energy Networks Association, Engineering Directorate, July 2006.
[16] CLNR-L071, 2014. “CLNR Customer Trials – A Guide to the Load and Generation Profile Datasets”, Report L071 of the Customer Led-Network Revolution project, August 2014.

networks and to identify whether appropriate modifications to the standard should be made. In particular, the security of supply standard for the planning and design of distribution networks suggests that "the contribution to System Security from DG plant specified in ER P2/6 and ETR 130 have been derived from the best data available at the time. Therefore, in the event that more accurate data becomes available it may be appropriate to review the contributions quoted in ER P2/6 and ETR 130". Based on the learning outcomes of the CLNR project, this subsection highlights some of the challenges associated with the current ETR 130 planning and design standard.

C1. Review of current and development of new F factors representing the contribution of different distributed generation technologies to distribution network security.

"Table 2" and "Tables 2.n" of the ER P2/6 specify the network security contribution that could be credited to a specific type of non-intermittent and intermittent DG. This type of assessment requires accurate information regarding the number, ratings and operating regimes of the distributed generators within a demand group. The new information collected from the CLNR customer field trials on the operating regime of current DG will support the review of the current and the development of new F factors enabling DNOs to better recognise the contribution that current distributed generation makes to the system security of the electricity distribution network and therefore maintain the techno-economic efficiency of the distribution network investment.

C2. Methodological challenges:

C2a - Combination of security contributions from different units.

Within the ETR 130 approach, the total capacity contribution (i.e. MW) from a demand group's DG is found by simple addition of the contributions from each DG technology contained within the demand group. For the standard to be internally consistent, this same capacity contribution would have to be found by calculating an F factor for the whole collection of DG in one step approach. However, examination of the F factor definition shows that this is not in general the case.

C2b - System structure for the underlying calculations of the F factor.

There are various assumptions in the F factor calculation approach which are substantially at variance with the reality of real distribution systems and the way the standard is applied. At one level, the rescaling of peak demand to the installed DG capacity breaks the link to the real system. More fundamentally, however, the F factors do not transparently represent the contribution of the DG in any particular risk calculation which is relevant to the real system under study; the F factor essentially compares the risk level of an islanded demand group supplied only by the DG with that in a system without the DG but with a perfectly reliable incoming circuit, but this capacity contribution is then used with respect to the N-1 or N-2 state of the real system. These uncontrolled assumptions expose the system to unknown, and potentially substantial, risks when the security contribution from DG compared to that provided from network assets is significant[17].

C2c - Extension of the deterministic standards.

Capacity values are usually assigned to DG resource as a deterministic MW equivalent to the security from network assets which gives the same risk level, or by quantifying the additional demand which the resource can support while maintaining the same risk level. This presupposes that there is an "original" risk level, however without the DG the P2/6-ETR 130 standard essentially says that under defined circumstances all demand must be met always, i.e. no finite baseline risk level is defined. This is an example of a more general challenge with deterministic standards, namely that there is often no natural way in which to extend them to a more complex world in which an increased number of resources or demands must be taken into account.

5.6 Impact assessment for the review of ETR 130 standard

The security of supply standard for the planning and design of distribution networks states that "the contribution to System Security from DG plant specified in ER P2/6 and ETR 130 have been derived from the best data available at the time. Therefore, in the event that more accurate data becomes available it may be appropriate to review the contributions quoted in ER P2/6 and ETR 130". The impact assessment uses the datasets collected from customer field trials of the CLNR project to review current and develop new F-factors representing the contribution of different distributed generation technologies to distribution network security.

5.6.1 Impact assessment approach

TC8 (i.e. "Basic profiling of distributed generation") of the CLNR customer field trials has provided half-hourly average power output metered data for a range of DG sites within the Yorkshire and Northeast electricity distribution networks. The collected data is representative of a variety of different technology types and DG configurations covering a two-year period from March 2009 to May 2011. The impact assessment applies the current methodological approach of ETR 130 to quantify new sets of F factors for the DG technology types monitored in TC8 and establishes a comparison with the original ETR 130 F factors. In particular, the assessment uses the computerised model of the methodology introduced in ETR 131. The key findings of the impact assessment were then used to devise recommendations to consider during a future review and update of the ETR 130.

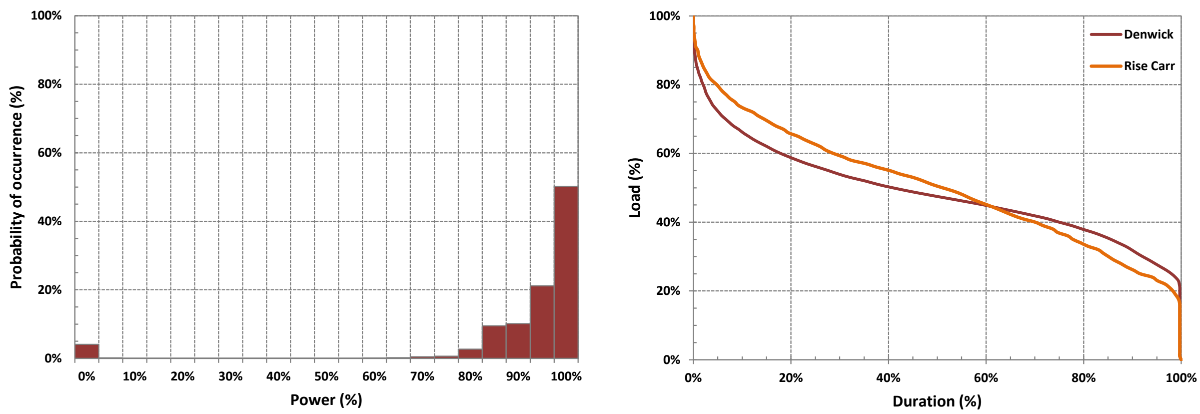
In order to ensure the applicability of the ETR 130 method and respective calculation of F factors, the data compilation and validation process gathered information of the DG sites with known nameplate rating and technology type only. In this respect, the breakdown of the admissible datasets by technology type is as follows:

- Landfill Gas: 25 sites;

[17] For a detailed technical description of the relevant risk modelling and capacity value calculation issues refer to: C. Dent, et al., 2014. "Defining and Evaluating the Capacity Value of Distributed Generation", Submitted to IEEE Transactions on Power Systems, 2014.

- Combine Heat and Power (CHP): 10 sites;
- Gas: 7 sites;
- Biomass: 2 sites;
- Wind: 16 sites; and
- Small hydro: 2 sites.

The data collected from the CLNR customer field trials is used within the ETR 130 F factor methodology to characterise the operational behaviour of DG sites of a particular technology. The performance of each DG site is then statistically assessed through its probability distribution that is constructed from the half hour time series of the active power output of the monitored DG site. Group demand is represented by the annual half hour time series of electricity demand of a particular substation and subsequently converted into a load duration curve (LDC). Northern Powergrid has provided for this impact assessment two distinct LDCs (i.e. Denwick and Rise Carr) to represent load demands across a wide range of electricity distribution networks in the UK. In order to preserve consistency with the studies performed to develop "Table 2" of ETR 130, the LDC for the winter period is considered. The probability distribution of DG performance and the LDC of the network load of a substation are then superimposed to quantify the EENS and the capability of DG to meet that group demand (i.e. F factor). Figure 5.5 provides an illustration of the DG and load characteristics used for the assessment of the F factors. Specifically, Figure 5.5a depicts the probability distribution of the operational performance of a single monitored Landfill Gas site and Figure 5.5b illustrates the annual LDCs.



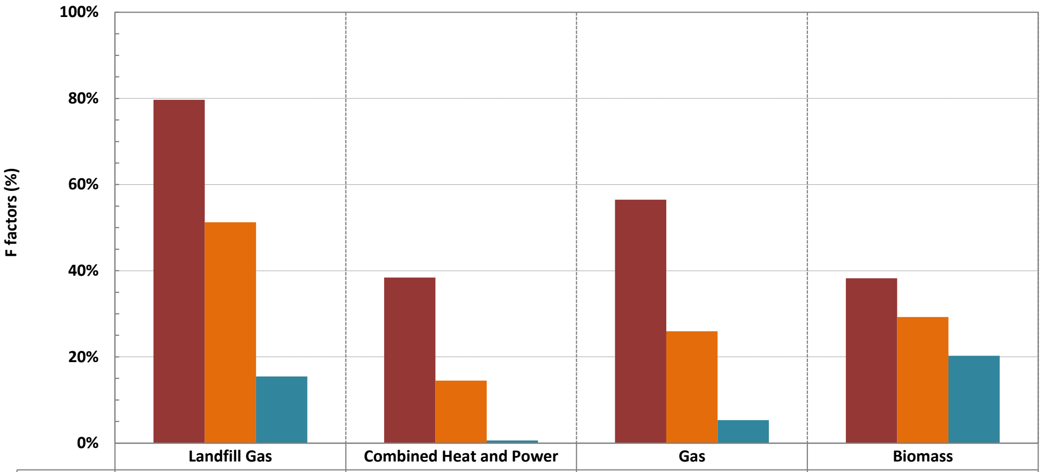
(a) Probability distribution of the operational performance of a monitored Landfill Gas site

(b) Load duration curve

Figure 5.5: Distributed generation and load characteristics

The calculation process of F factors, for each technology specific DG site, combined each of the two monitored years of active power output of DG with each of the two LDCs resulting in a total number of four distinct combinations between DG and LDC. These four configurations cover a good range of design situations. The computation of F factors has been performed with the software package developed for assessing the security capability of DG described in ETR 131.

Figure 5.7 presents the range of F factors quantified for the non-intermittent DG technologies considered in the customer field trials of the CLNR project.



	Landfill Gas	Combined Heat and Power	Gas	Biomass
Maximum	80%	38%	56%	38%
Average	51%	14%	26%	29%
Minimum	15%	1%	5%	20%

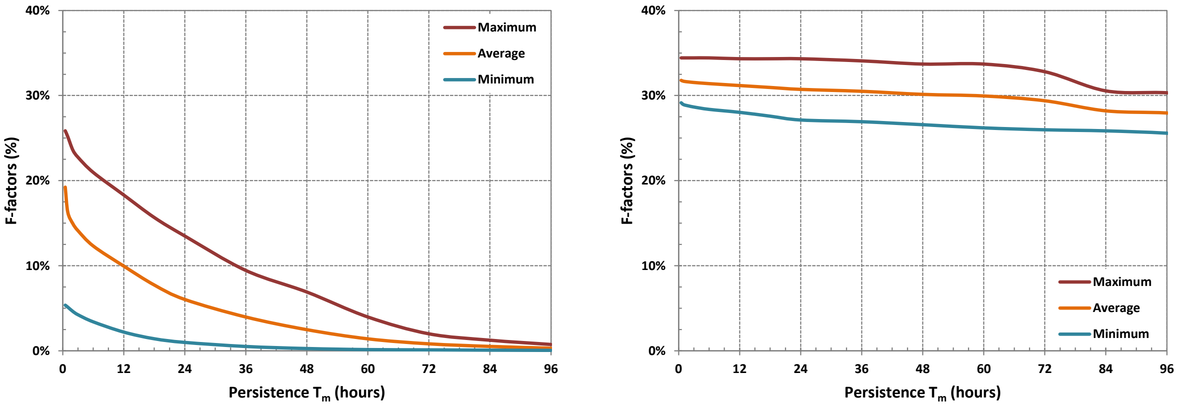
Figure 5.6: F factors for non-intermittent DG technologies

It can be seen in Figure 5.6 that the capacity contribution of DG to system security can vary significantly across different technology types of plant and also for different plants of the same type. For instance, the average F factor varies from 14% for CHP to 51% for Landfill Gas plants. Furthermore, under the same technology type, the F factor for Landfill Gas sites ranges from a minimum of 15% to a maximum of 80%.

The contribution of DG to system security is driven by various factors related to both generation and load. On the generation side factors such as the availability of the generating units that constitute the DG plant, the number of units, the size of the units and their operating regime can have a significant impact on the F factors. On the load side, drivers such as the magnitude and duration of the peak load can affect the contribution of DG plants to system security.

In Figure 5.6, the variability observed in the capacity contribution of DG was found to be mainly driven by the operating regime of the DG plants under consideration and consequently their availability. It is noted that the overall availability of the technology specific DG site is implicitly considered in the time series of the operational performance of the DG plants observed in the trials. Broadly, the overall availability includes attributes related to: (i) technical availability which reflects whether the facility is in a working state; (ii) energy availability which reflects whether energy is available to drive the generating units; and (iii) commercial availability which reflects whether it is commercially available. For example, a Gas plant generally has high technical availability, typically above 90%, together with good fuel availability. However, when operated as a merchant DG plant with its main objective being to meet energy contracts, or provide energy balancing services, the availability of its full output is under control of the 'Generator' and will be varied for purely commercial reasons. Based on the data available from the CLNR customer field trials, it is extremely difficult to attempt disaggregating the overall availability of the DG site into the three aforementioned availability types.

Figure 5.6 presents the range of F factors quantified for the intermittent DG technologies considered in the customer field trials of the CLNR project. The F factors for intermittent generation are related directly to the persistence time T_m, i.e. the period of time for which generation will need to operate continuously at or above a certain output level in order to support the demand and hence to provide system security. This period of time is related to the duration of the system conditions for which such generation may be able to avoid or reduce customer disconnections. Broadly, intermittent generation sources persist in generating at a particular output level for significantly shorter periods of time.



(a) Wind farm **(b) Small hydro**

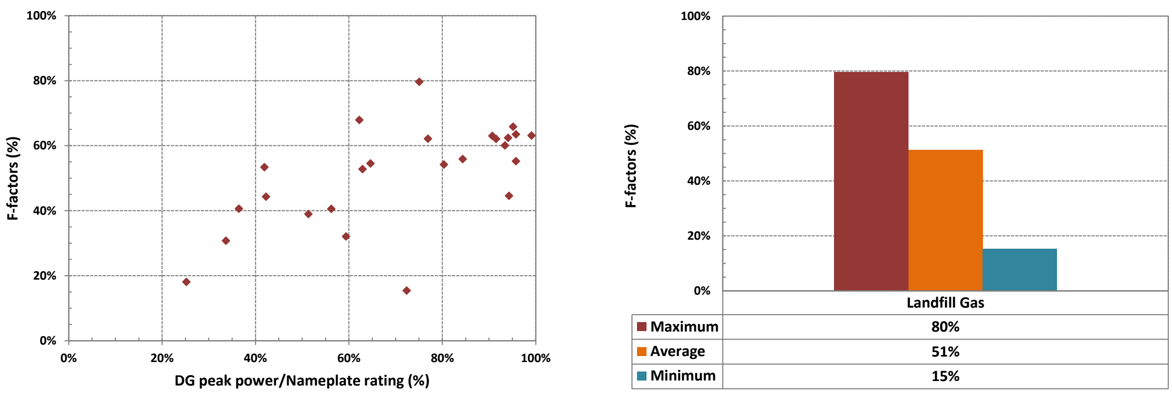
Figure 5.7: F factors for intermittent DG technologies

It can be observed in Figure 5.7 that increasing the level of required persistence reduces the contribution of intermittent generation to security. For example, it is seen in Figure 5.7a that the average contribution of the wind farm to network security decreases from about 20% for T_m = ½ hr to 6% for T_m = 24 hr.

The following subsections present the technology-specific contribution of DG to distribution network security for the sites monitored in the CLNR project.

5.6.2 Landfill Gas

The data compilation and validation process of TC8 collected adequate and sufficient information for the computation of F factors for 25 DG Landfill Gas sites. The nameplate rating of these sites ranges from 0.3MW to 8MW. The set of F factors quantified for the 25 monitored DG Landfill Gas sites are presented in Figure 5.8.



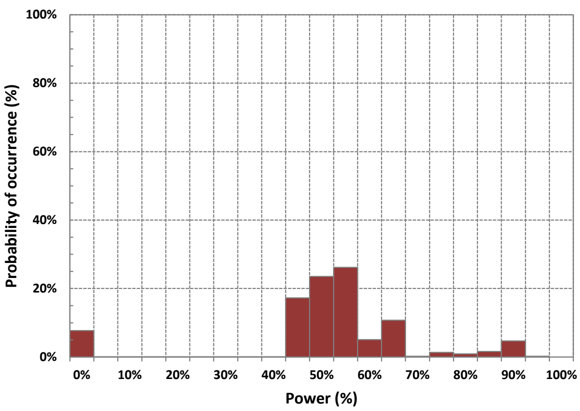
(a) Distribution of F factors **(b) Statistics of F factors**

Figure 5.8: F factors for Landfill Gas sites

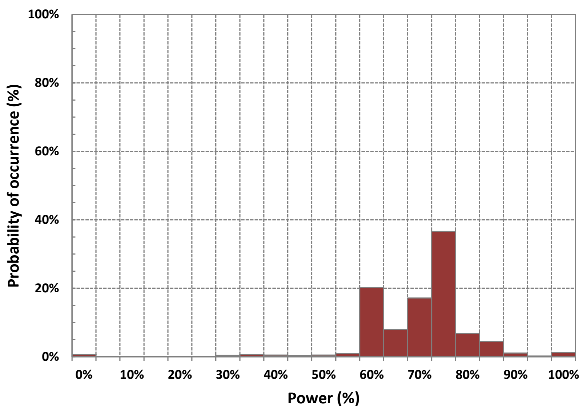
It can be inferred from Figure 5.8 (b) that the mean F factor over the four configurations of DG and LDC is 51%. A Landfill Gas site with a nameplate rating of 1MW could usually be expected to support a maximum demand of 0.5MW. The sample standard deviation is found to be relatively wide and is estimated to be 17%. This reflects the significant variation of the contribution of different Landfill Gas sites to system security as demonstrated in Figure 5.8 (a). It should be mentioned that the mean F factor over the four configurations between DG and LDC has been presented as the impact of these different configurations on the F factor was found to be marginal.

It is seen in Figure 5.8 (a) that distributed generators operating with a peak power output near to their nameplate rating (i.e. 100%) are characterised by contribution to network security ranging from 60% to 65%. It is noted that the F factor provided by ETR 130 for a Landfill Gas site constituted of one generating unit is 63% based on technical availability only. Nevertheless, the operating regime (i.e. including technical, fuel and commercial availabilities) of a generator is clearly seen to have an important effect on the contribution of the site to system security. Hence, for a generator operating with a peak power output of only 40% of the nameplate rating, the F factor is observed to be closer to 40%.

In this context, Figure 5.9 (b) shows that from the 25 DG Landfill Gas sites considered in the analysis, the F factor varies significantly from a minimum of 15% to a maximum of 80%. Figure a and Figure b detail the operational performance of the Landfill Gas sites that result in the minimum and maximum levels of the contribution to network security, respectively.



(a) Probability distribution of Landfill Gas site with 15% contribution to network security



(b) Probability distribution of Landfill Gas site with 80% contribution to network security

Figure 5.9: Operational performance of Landfill Gas sites

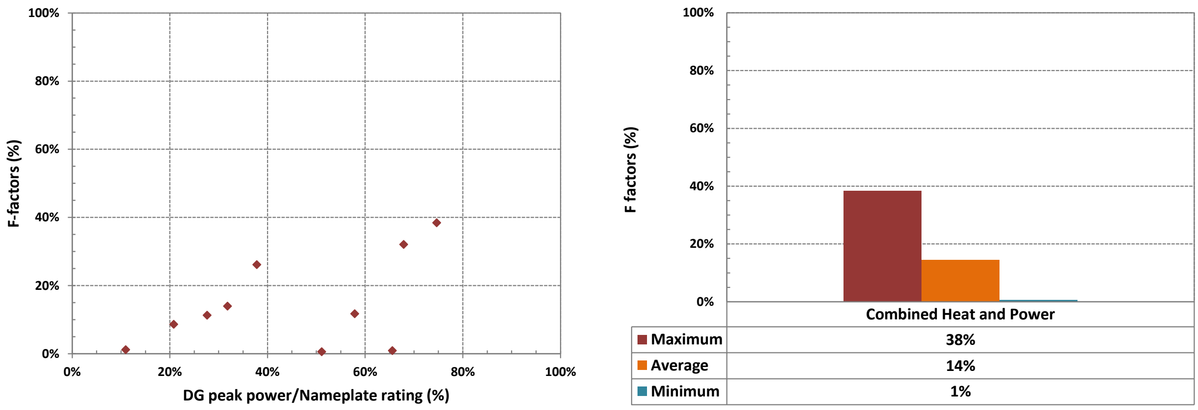
The Landfill Gas site in Figure 5.9 (a) is characterised by a nameplate rating of 0.34MW and an annual average load factor of 50%. It can be seen in Figure 5.9 (a) that there is approximately 8% chance of this site being out of service. Moreover, it is observed that power output levels between 45% and 55% of the nameplate rating of this site have the highest likelihood of occurrence that is estimated to be around 67% overall. This means that for most of the time that this Landfill Gas is in operation, its power output is in the region of 50% of its nameplate rating. As a consequence, the operation performance of this DG site results in a limited contribution to network security.

The Landfill Gas site in Figure 5.9 (b) is characterised by a nameplate rating of 2.5MW and an annual average load factor of 70%. It is observed that the likelihood of power outputs between 0% and 55% is practically negligible whilst the most likely power output level is estimated to be around 75% of the nameplate rating of this site. In this respect, the operation performance of this DG site results in a significant contribution to network security. The 2.5MW nameplate rating site could usually be expected to support a maximum demand of 2MW.

The CLNR project provides the half hour time series of the active power output of the monitored DG Landfill Gas sites that can be directly applied within the current ETR 130 framework to evaluate the contribution of DG to distribution network security.

5.6.3 Combined Heat and Power

The data compilation and validation process of TC8 collected adequate and sufficient information for the computation of F factors for 10 DG CHP sites. The nameplate rating of these sites ranges from 0.1MW to 39MW. The set of F factors quantified for the 10 monitored DG CHP sites are presented in Figure 5.10.



(a) Distribution of F factors

(b) Statistics of F factors

Figure 5.10: F factors for Combined Heat and Power sites

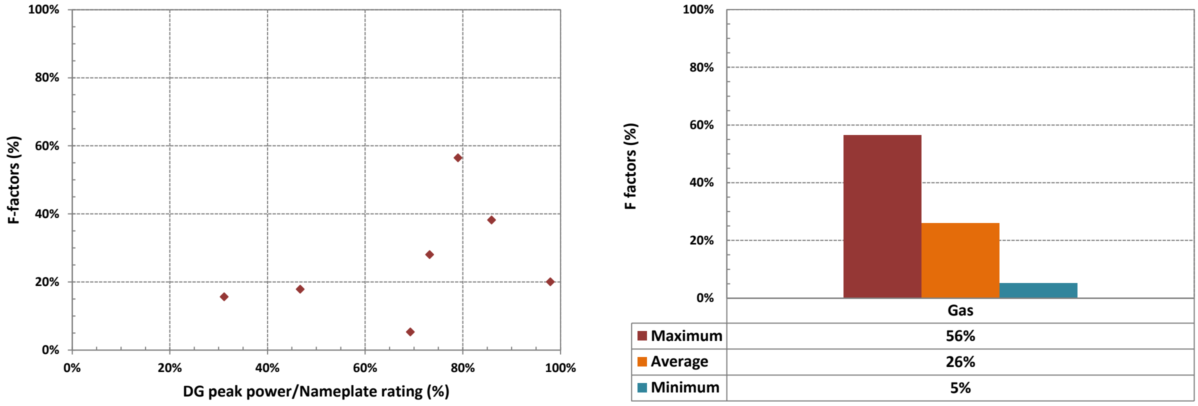
It can be derived from Figure 5.10(a) that the mean F factor over the four configurations of DG and group demand is 14%. A CHP site with a nameplate rating of 1MW, could usually be expected to support a maximum demand of 0.14MW. The sample standard deviation is found to be relatively wide and is estimated to be 13%. Figure 5.10(b) shows that from the 10 DG CHP sites considered in the analysis, the F factor varies significantly from a minimum of 1% to a maximum of 38%.

The CLNR project provides the half hour time series of the active power output of the monitored DG CHP sites that can be directly applied within the current ETR 130 framework to evaluate the contribution of DG to distribution network security.

5.6.4 Gas

The data compilation and validation process of TC8 collected adequate and sufficient information for the computation of F factors for 7 DG Gas sites. The nameplate rating of these sites ranges from

2MW to 12MW.The set of F factors quantified for the 7 monitored DG Gas sites are presented in Figure 5.11



(a) Distribution of F factors

(b) Statistics of F factors

Figure 5.11: F factors for Gas sites

It can be estimated from Figure 11 (a) that the mean F factor over the four configurations of DG and group demand is 26%. A Gas site with a nameplate rating of 1MW, could usually be expected to support a maximum demand of 0.26MW. The sample standard deviation is found to be relatively wide and is estimated to be 16%. Figure 5.11 (b) shows that from the seven DG Gas sites considered in the analysis, the F factor varies significantly from a minimum of 5% to a maximum of 56%.

The CLNR project provides the half hour time series of the active power output of the monitored DG Gas sites that can be directly applied within the current ETR 130 framework to evaluate the contribution of DG to distribution network security.

5.6.5 Biomass

The data compilation and validation process of TC8 collected adequate and sufficient information for the computation of F factors for only two DG Biomass sites. The nameplate rating of these sites ranges from 1MW to 3MW.The set of F factors quantified for these two monitored sites are presented in Figure 5.12.

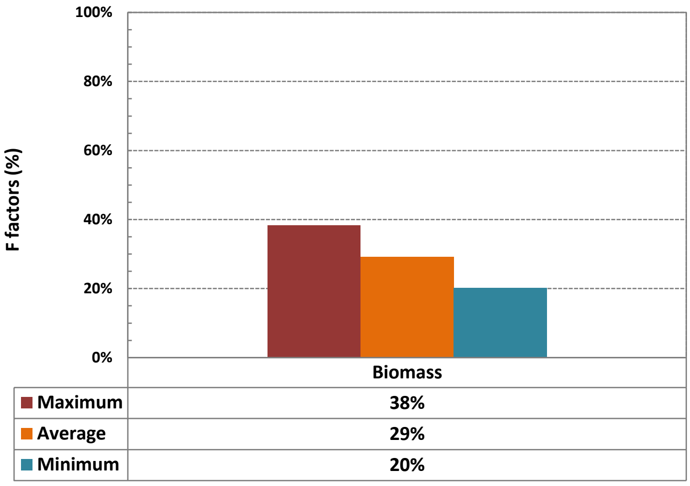


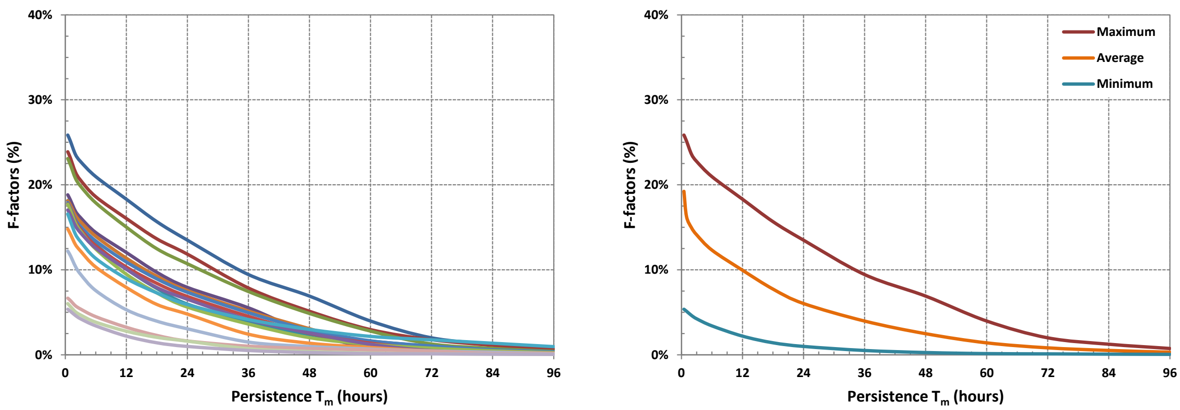
Figure 5.12: F factors for Biomass sites

It can be observed in Figure 5.12 the F factor for the DG Biomass sites varies from a minimum of 20% to a maximum of 38%. It is stressed that the datasets used to create this Figure 5.12 have limited statistical robustness due to data scarcity.

The CLNR project provides the half hour time series of the active power output of the monitored DG Biomass sites that can be directly applied within the current ETR 130 framework to evaluate the contribution of DG to distribution network security.

5.6.6 Wind

The data compilation and validation process of TC8 collected adequate and sufficient information for the computation of F factors for 16 DG Wind sites. The nameplate rating of these sites ranges from 0.02MW to 30MW. The time series representing the operational performance of the DG Wind sites is constituted of 30-minute time intervals. Since wind output may vary considerably during each half hour, the variation in associated levels of generation would need to be absorbed by the remaining network circuits. For a short period of time, the generation output could drop significantly and hence the remaining circuits may become overloaded. ETR 131 recommends using a five-minute sample rate to take account of the effect of these short term fluctuations of the wind resource. ETR 131 then provides a table of 'Correction Factors' for wind farm contribution, for typical values of T_m (ETR 131, Figure 18). This table has been used in this work to scale the wind farm data by the appropriate data resolution 'correction factors'. The F factors quantified for the 16 monitored DG Wind sites are presented in Figure 5.13 for different persistence values of T_m.

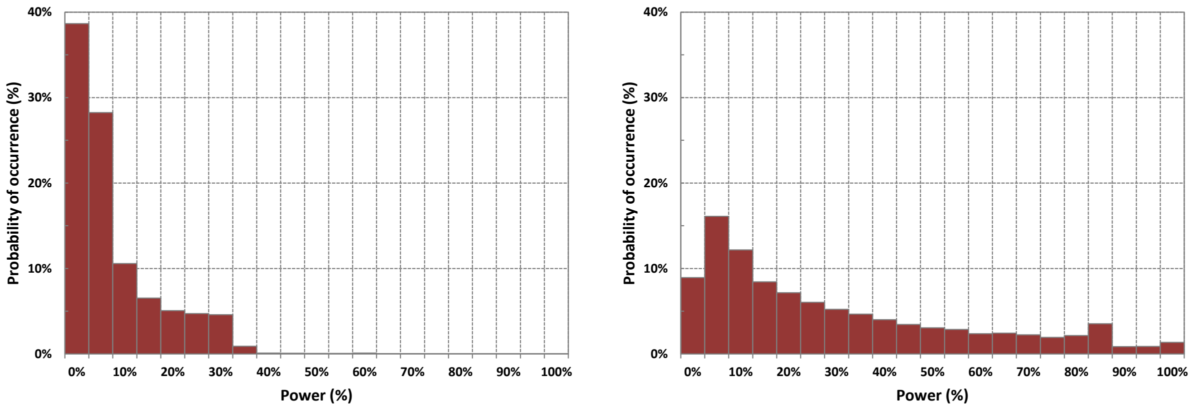


(a) Distribution of F factors **(b) Statistics of F factors**

Figure 5.13: F factors for Wind sites

It can be seen in Figure 5.13 (a) that the capacity contribution of DG Wind to system security can vary significantly across different sites due to the variable nature of the wind resource. For instance, for T_m = ½ hr the F factors range from 5% to 26%. It is also seen that increasing the level of required persistence reduces the contribution of the DG Wind sites to security, as expected.

Figure 5.14 (a) and Figure 5.14(b) detail the operational performance of the monitored wind sites that result in the minimum and maximum levels (i.e. from Figure 5.13(b) of contribution to network security, respectively). The Wind site in Figure 5.14 (a) is characterised by a nameplate rating of 1.8MW and an annual average load factor of 6% whilst Figure 5.14(b) represents a wind site of 9.3MW of nameplate rating and 28% annual average load factor.



(a) Probability distribution of a Wind site for the minimum observed contribution to network security

(b) Probability distribution of a Wind site for the maximum observed contribution to network security

Figure 5.14: Operational performance of wind sites

It can be seen in Figure 5.14 (a) that the likelihood of no or very low wind power output is relatively high. Furthermore, the maximum power output observed in this Wind site is as low as 35% of the nameplate rating. Thus, it is expected that the ability of this DG site to contribute to network security is very low as previously demonstrated. In contrast, Figure 5.14 (b) represents a wind site characterised by higher availability of the wind resource over a wide range of power outputs levels. In this sense, the operation performance of the latter DG site results in a relatively higher contribution to network security.

Table 5.1 establishes a comparison of the average F factors across the 16 monitored DG Wind sites (i.e. average curve in Figure 5.14 (b) against the original F factors of wind farms specified in the ETR 130.

Cases	T_m						
	0.5	2	3	18	24	120	360
ETR130: F factors for wind farm	28%	25%	24%	14%	11%	0%	0%
CLNR Trials: Average F factors for wind farm	19%	15%	14%	8%	6%	0%	0%

Table 5.1: Comparison of the F factors of wind farms from ETR 130 against the CLNR monitored sites

Table 5.1 shows that the F factors for wind farm can vary significantly depending on the characteristics of the wind resource. For example, for Tm = ½ hr the contribution to network security of the wind farms considered in the ETR 130 studies is 28% whilst the contribution to network security based on the monitored sites of the CLNR project is estimated to be 19%.

Based on the real-world customer field trials of the CLNR project it has been observed that the capacity contribution of DG Wind to system security can vary significantly across different plants of the same type and that F factors for DG Wind were found to be significantly lower than those specified in ETR 130.

The CLNR project provides the half hour time series of the active power output of the monitored DG Wind sites that can be directly applied within the current ETR 130 framework to evaluate the contribution of DG to distribution network security.

5.6.7 Small Hydro

The data compilation and validation process of TC8 collected adequate and sufficient information for the computation of F factors for only two DG Hydro sites. The nameplate rating of these sites ranges from 0.1MW to 5MW. The set of F factors quantified for these two monitored sites are presented in Figure 5.15 for different persistence values of T_m.

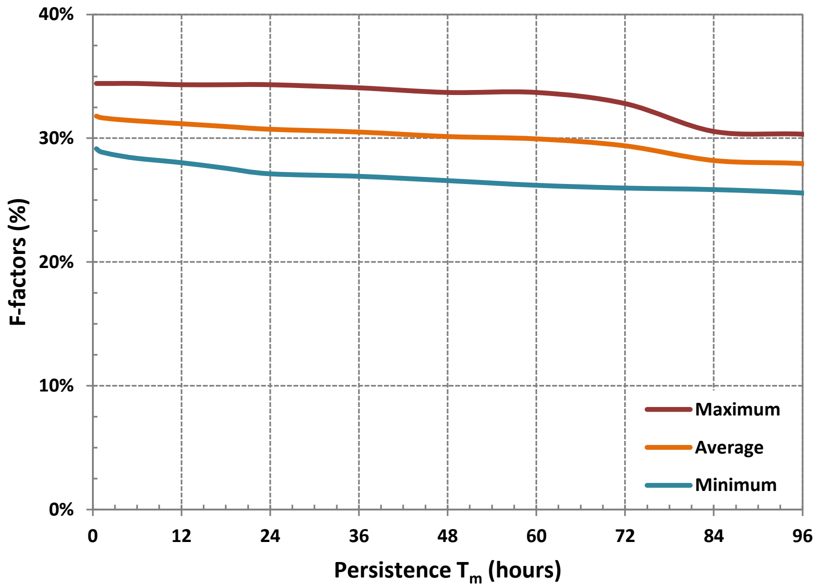


Figure 5.15: F factors for Hydro sites

It can be observed in Figure 5.15 that for T_m = ½ hr the F factor for the DG Wind sites varies from a minimum of 29% to a maximum of 34%. It is stressed that the datasets used to create this Figure 5.15 have limited statistical robustness due to data scarcity.

Table 5.2 compares the average F factors across the two monitored DG hydro sites i.e. average curve in Figure 5.15 against the original F factors of wind farms specified in the ETR 130.

Cases	T_m						
	0.5	2	3	18	24	120	360
ETR 130: F factors for small hydro	37%	36%	36%	34%	34%	25%	13%
CLNR Trials: Average F factors for small hydro	32%	32%	32%	31%	31%	27%	21%

Table 5.2: Comparison of the F factors of small hydro from ETR 130 against the CLNR monitored sites

Table 5.2 shows that the F factors for small hydro based on the monitored sites of the CLNR project are found to be relatively close to those of ETR 130. Nevertheless, it should be noted that different operating regimes of DG can lead to very different contributions to network security.

The CLNR project provides the half hour time series of the active power output of the monitored DG Wind sites that can be directly applied within the current ETR 130 framework to evaluate the contribution of DG to distribution network security.

5.7 Recommendations for the review of ETR 130 standard

Based on the learning outcomes and real-world field trials of the CLNR project, the key recommendations to consider during a future review and update of ETR 130 can be summarised as follows:

Recommendation 1: To update the current F factors for the contribution of different DG technologies to distribution network security based on the data collected from the customer field trials of the CLNR project.

The security of supply standard for the planning and design of distribution networks suggests that "the contribution to System Security from DG plant specified in ER P2/6 and ETR 130 have been derived from the best data available at the time. Therefore, in the event that more accurate data becomes available it may be appropriate to review the contributions quoted in ER P2/6 and ETR 130". In this respect, it is recommended to update the current F factors for the contribution of different DG technologies to distribution network security based on the data collected from the customer field trials of the CLNR project. This supports DNOs to better recognise the contribution that DG makes to the system security and therefore to comply with the security requirement ER P2/6. It should be noted that the data used to derive the revised F factors is based on generators in Northern Powergrid licence areas.

Recommendation 2: To use the information collected from the customer field trials and associated learning outcomes of the CLNR project to support the "Review of ER P2/6 Working Group" of the Distribution Code Review Panel on the review of ETR 130 methodology for assessing the contribution of DG to network security.

The consideration within the CLNR project of the modelling structure underlying ETR 130 reveals a number of concerns about how the planning methodology contained therein relates to the real system situations under study. In general, if a simplified approach (such as the F factors used at present) is to be used in assessing the contribution of DG and other new technologies in practical planning, then such a simplified approach should have a sound basis in a particular risk calculation relevant to the real network situations under study. This might either be based in a probabilistic calculation with a particular target risk level, or in a probabilistic cost-benefit analysis between investment cost and future reliability cost.

More generally, there is no natural way of extending a deterministic standard such as the present ETR 130 and P2/6 to include distributed resources. The only natural basis for considering such new components of the system is to develop a fully probabilistic risk-based planning approach, which can integrate consideration of all relevant technologies. There are clear advantages of using a simplified approach such as the present F factors for practical purpose (including resource expended on any individual study, and applicability by a wide range of planning engineers who are not experienced in probability techniques), but in order to have confidence that such an approach will deliver good results it should have a sound basis in a fully detailed calculation.

Hence, it is recommended to make use of the information collected from the customer field trials and associated learning outcomes of the CLNR project to support the "Review of ER P2/6 Working Group" of the Distribution Code Review Panel on the review of ETR 130 methodology for assessing the contribution of DG to network security.

6 Learning from the CLNR I&C trials

6.1 Purpose of the CLNR I&C trials

The CLNR project tested a direct control proposition which requires industrial and commercial (I&C) customers to adapt their energy usage patterns upon request to create a controllable power flow by either increasing generation or reducing load. Trials were carried out in 2012 and 2014.

The 2012 trials involved physical DSR trials with three I&C sites signed via two commercial aggregators and also included a wider survey of customer attitudes to DSR. The key objectives of these trials were to:

- Assess the network requirement
- Develop the I&C DSR product
- Assess the market entry channels
- Develop relationships with DSR providers
- Design and execute DSR contracts
- Assess the recruitment challenges for acquiring DSR at specific geographic locations; and
- Assess the operational trials

The second set of trials involved 13 customers signed via three aggregators and one customer contracted directly to Northern Powergrid. These trials sought to prove:

a) the commercial concept, that
   - it is possible for DNOs to contract for DSR services both directly with I&C customers and via aggregators.
   - I&C customers are willing to accept a variety of validation and payment methodologies.
   - I&C customers are willing to accept a price that is cost competitive with the cost of reinforcement.

b) the paired technical concepts, that
   - a DSR response can be relied upon to deliver the service required to address localised network constraints; and
   - we can build an end-to-end active network management scheme to monitor what customers are doing on the network, identify constraints, then initiate and deliver solutions to relieve those constraints.

The key development items for the 2014 trials were to:

- Build a larger DSR trial portfolio to test response from a broader cross-section of the I&C customer base;
- Trial an additional contract framework;
- Initiate the call for DSR from monitoring devices on the trial network;
- Undertake a survey of trial participants; and

- Enhance the communication despatch protocols between the DNO and the aggregators for DSR by utilising the CLNR active network management system to issue DSR instructions direct to the aggregators and I&C customers.

This report provides an overview of the learning from this aspect of the project, specifically in the following areas:

- Network requirements assessment
- Customer engagement
- Commercial arrangements
- Trial operation and results

6.2 Network requirements assessment

A methodology was developed during the 2012 trials for assessing the network requirements and for identifying suitable DSR participants;

6.2.1 Network requirement for a 'fast reserve' post fault DSR product

All distribution network operators (DNO) design their networks to provide the required level of security under network fault conditions. The objective of the I&C flexible response is to address operational constraints that arise after network failure if the network is loaded more fully to cater for the increase in connection of low carbon technologies. This response is only required when the network has incurred a fault, the requirement is therefore an on-demand response rather than a day-in, day-out response.

6.2.2 Network constraint

The network constraint which requires intervention is a heavily-loaded primary substation. The supplies to these nodes are designed with N-1 redundancy, i.e. they are intended to support full demand even with one incoming circuit out of commission. Those incoming circuits are the most reliable on the network, because they are used to secure supplies to large numbers of customers. On a fully loaded primary, these circuits are each carrying half their rated capacity when running in parallel at the time of system maximum demand but could be lightly loaded the majority of the time. They could therefore offer more capacity if customers were to agree to moderate their requirements under single circuit outage conditions if this happened to also coincide with the period of peak demand.

6.2.3 Customer role

The role of customers is to offer load reduction / generation, thereby "shaving" peak demand, when a circuit is lost due to a fault at a time when unconstrained peak demand would be at its highest (typically, November-February). This facility could extend the asset life by deferring network reinforcement. The reduction in demand would be scaled back to the capability of the remaining assets. Generally a reduction of 10% of peak demand at the primary substation is sufficient (approx. 2MW – 4MW). In the course of normal operations, all the incoming circuits are in commission, so the demand response will not be required. Planned outages would be confined to the period between March and October, to avoid activation of the demand response for planned work. The I&C

flexibility product is, in effect, an insurance policy to be claimed against if a network fault occurs at the time of peak demand.

6.2.4 Network evaluation process

Having defined the concept for the 'fast reserve' post fault DSR product, the next stage was to simulate the asset management planning process to understand how this new tool would be incorporated into existing business processes.

Northern Powergrid undertakes network load forecasting annually in order to identify locations where there is a risk that forecast demands will exceed the substation firm capacity. These Distribution Load Estimates (DLEs) provide a high level indication of the potential future demand on the EHV distribution network and form the starting point for the assessment of potential load related reinforcement expenditure. The results are formally documented and published to the business and contain a year-on-year estimate of the electrical demand on each of the Primary and Supply Point Substations together with an indication of where the existing, or forecast demands may exceed the capability (firm capacity) of a substation.

The process of producing the DLEs includes the following:

- A detailed review of each Primary and Supply Point substation demand profile;
- An assessment of the current maximum demand;
- Application of any necessary data normalisation;
- Forecasting of underlying network load growth;
- Forecasting the impact of known large load changes;
- Forecasting the impact of known large generation changes;
- Identification and assessment of embedded generation in service; and
- Analysis and initial investigation of potential issues.

6.2.5 Load profile analysis

Once the primary substations at or nearing firm capacity have been identified through the DLEs, analysis of the load profile is required in order to ascertain whether DSR can provide an alternative to network reinforcement. Figure 6.1 shows the average monthly power consumption at a primary substation.

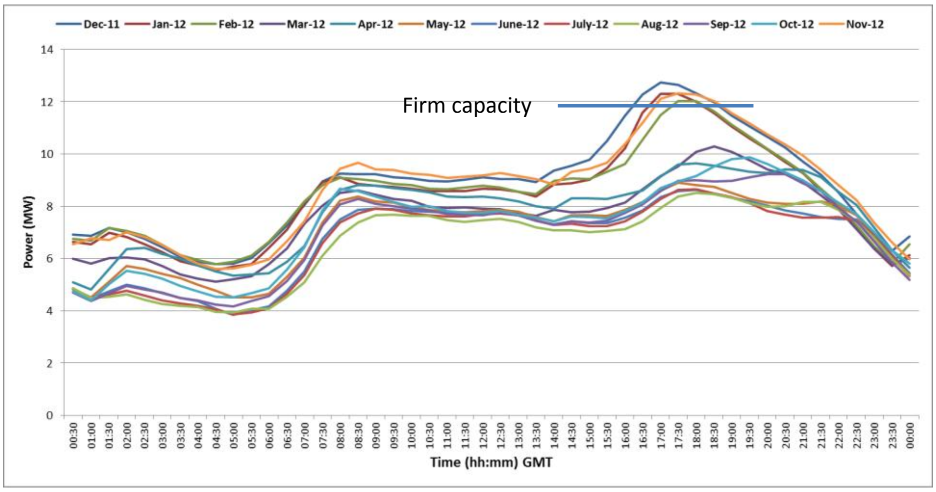


Figure 6.1: Average monthly power consumption per half hour for primary substation

It can be seen from the profile for this particular primary substation, that DSR could provide a solution to reduce the peak demand and would be required from November through to February between 16:00 and 19:00. However, there are some profiles that have no seasonal shapes, these substations may have high load factors, in these situations DSR is unlikely to be an economic alternative as the DSR product cannot target specific seasons or potentially times during the day. In these situations conventional asset reinforcement is more likely to be required.

6.2.6 Customer matching requirements

To determine whether DSR is a real alternative to network reinforcement, analysis needs to be carried out to establish whether the customers located on that part of the network have a load shape which could offer DSR for the selected primary substation. Figure 6.2 shows a comparison of the load profile of a primary substation and a potential DSR provider for December 2011 to February 2012.

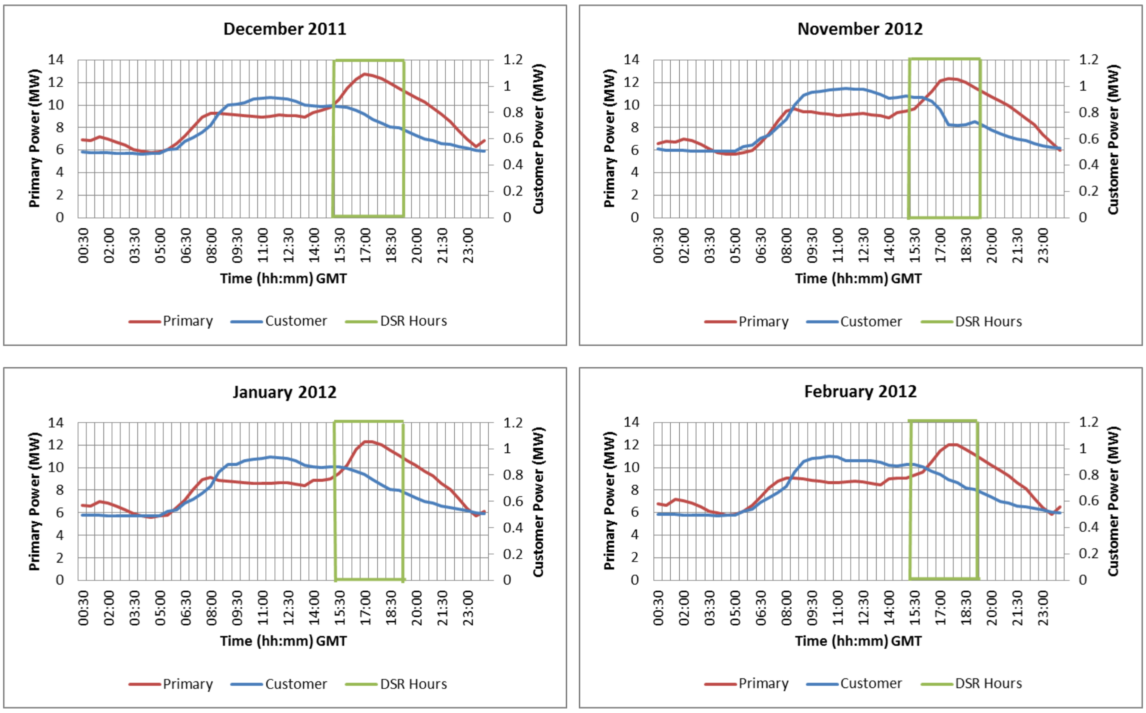


Figure 6.2: Comparison of primary substation and customer's average monthly power consumption per half hour

It can be seen from these profiles that this particular customer is able to provide DSR during the months and time periods required. Once again, there are situations where the portfolio of I&C customers in that location will not match the network load profile requirements. In this scenario I&C DSR will not be a viable alternative to convention network solutions.

6.3 Market channel assessment

DSR is a developing market in the UK and the most efficient route to market has not yet been identified for DNOs. A number of options are available to engage with this market, which include working with:

- I&C customers directly;

- Aggregators;
- Suppliers; and
- National Grid (the Transmission System Operator).

For the 2012 trials the CLNR project focused on developing working relationships with three aggregators as the customer facing entity. The aggregators bring a number of capabilities of value to the project, these included the ability to:

- identify customers with flexibility potential in our regions;
- work with customers to develop the capability to provide flexibility;
- provide technical assistance for customers with metering, equipment upgrades and communications;
- execute commercial agreements to monetise the arrangements; and
- implement operating procedures.

For the 2014 I&C trials the project continued to work with the aggregators but, in addition, we engaged directly with one major I&C customers. This has given us some direct customer engagement experience and provides a valuable comparison of the aggregator model compared to a DNO dealing directly with customers. We have also been involved in industry work, led by the ENA as part of the Energy Networks Futures Group (ENFG), to explore potential DSR sharing options between the Distribution Network Operators and the Transmission Network and System Operators.

Experience from the CLNR project, the work with the ENA, observations from other LCN Fund projects, reveal a number of potential current and future opportunities for accessing the DSR market. These will include, but not be restricted to:

- Building relationships with companies that have centralised energy management and have a widespread footprint in the DNO region operating on multiple sites (e.g. water, telecoms, local authorities, hospital trusts, supermarkets, etc.);
- Direct engagement with other significant known customers on the network;
- Working with National Grid for the sharing of STOR resource;
- Engagement via aggregators (including suppliers);
- Targeted marketing using MPAN information and load profiles and inviting companies to tender into a local capacity auction;
- In partnership with local bodies such as Chambers of Commerce; and
- Advertising through local media.

6.4 Customer engagement

To gain a more detailed understanding of how much potential industrial and commercial (I&C) demand side response (DSR) resource exists when targeting specific primary substations we commissioned a piece of research, undertaken for the project by two commercial aggregators. Ten primary substations were selected representing 1.5% of the Northern Powergrid major substation population. These ten substations supply a total of 251 I&C sites, 92 of which have a maximum demand greater than 200kW which is what we determined to be the minimum level of demand required to participate in I&C DSR schemes, for the purpose of the survey.

The customers offered a good representative mix of market sectors covering commercial offices, warehouses, health, retail, education, hotel and catering, sport and leisure, public sector, manufacturing, logistics, engineering, chemical, and pharmaceutical. Customers ranged from high street shops, supermarkets, hotels, schools and hospitals to water pumping and sewerage stations, ports, food processing, plastics and manufacturing plants.

Through a series of telephone conversations, questionnaires and meetings, the I&C customers in the selected primary areas were approached by commercial aggregators to assess their knowledge of DSR, establish their willingness and capability to participate in DSR and identify barriers to DSR programmes.

The key findings from the research were as follows:

- When targeting a tight geographic area the initial customer drop-out rates are high due to issues with contacting the sites, contacting the right person at the site, particularly a decision maker, and the size of site load (we consider 200kVA to be viable).
- When contact is made with the right person in the business there is a low level of awareness of what DSR is amongst customers (unless the customer is already a participant in existing DSR arrangements such as STOR).
- When the concept of DSR is explained to customers a large proportion of customers wanted to understand more about the practical opportunities and appeared willing to invest time and resources to develop their DSR capability, some even willing to consider the remote control access and control of their assets.
- Even if I&C customers show a positive interest in the DSR concept there may still be issues with some sites as further investigations identified limited flexibility to alter their load profiles.
- The implementation of DSR from generation substitution is the most successful entry point for new I&C customers wishing to participate in DSR schemes as it provides a new revenue stream while minimising the number of changes and new risk to their business operation. Following this first step, customers can then engage in developments that may be more intrusive to their core processes such as load management. Energy efficiency is also a good entry point for customers new to DSR.

The research resulted in 15 of the 251 customers identified, showing a potential interest in the concept of DSR.

Engagement Step	Aggregator 1	Aggregator 2	Total	%
Sought to engage	152	99	251	100%
Managed to speak	74	33	107	43%
Initially interested	30	22	52	21%
Still interested	14	7	21	8%
Still interested (> 200kVA)	9	6	15	6%

Table 6.1: Customers still engaged at each step of the engagement process

The research showed that it was not possible to contact 57% of the sites identified and that, of the sites contacted, it was only possible to find an appropriate person to speak to in just under 50% of them. There is therefore some way to go to improve the means of access to this market.

Turning to the potential capacity available from the sites that showed an interest in future participation in DSR, Table 6.2 below, shows the number of customers identified at each primary substation and their aggregate capacity:

Primary Substation	Potential DSR Requirement (MW)	No. Sites >200kW	Cumulative DSR Potential at Sites >200kW	No. Interested Sites >200kW	Cumulative potential DSR at interested sites (MW)
Primary 1	2	6	3.2	1	0.6
Primary 2	2	10	11.5	3	2.3
Primary 3	2	11	10.5	2	5.7
Primary 4	1	6	3.4	1	0.3
Primary 5	2	8	2.5	1	0.3
Primary 6	1	5	3	0	0
Primary 7	2	17	7.4	3	1.3
Primary 8	1	15	12.3	1	2.3
Primary 9	1	6	16.2	0	0
Primary 10	2	8	4	3	1.2
Total	**16**	**92**	**74**	**15**	**14**

Table 6.2: Potential DSR capacity at interested sited > 200kVA

The research exercise showed a potential to secure a total of 14MW of DSR resource from a total of 74MW available across the 10 primary substations.

From a total of 92 sites, 15 sites over 200kW remain interested in the concept of DSR.

However, only three of the primary substations had sufficient interested customers to deliver the potential DSR requirement so, if we were successful in signing all of the interested sites to a contract, we would be able to provide the required DSR at only the 3 primary substations shown highlighted in blue.

In summary, it is possible to find I&C customers willing to provide a DSR response but the process is time-consuming and resource intensive and there will be occasions when sufficient customers cannot be found to meet the load reduction requirements of the substation.

However, as the research shows, there could be significant potential to improve the rate of attrition when contacting customers through the development of improved information and engagement techniques.

Appendix B of the [2012 CLNR I&C DSR trials report] provides more detail of the research methodology and findings.

It was found from the 2012 trials that the lead times from making initial contact with a customer to finalising a DSR contract can range from 12 to 24 months. The time required to finalise the legal framework for DSR products is material and can take up to four months to go through the three stages of contractual design, negotiations with third parties; and legal counsel. It was therefore decided that for the 2014 trials we would contract with customers that already had experience of providing DSR under the STOR arrangements with National Grid and we engaged with one customer directly and 13 via three aggregators. Figure 6.3 shows the aggregators involved, the types of customers contracted and the method by which the response was provided. The gas production company was contracted directly by Northern Powergrid.

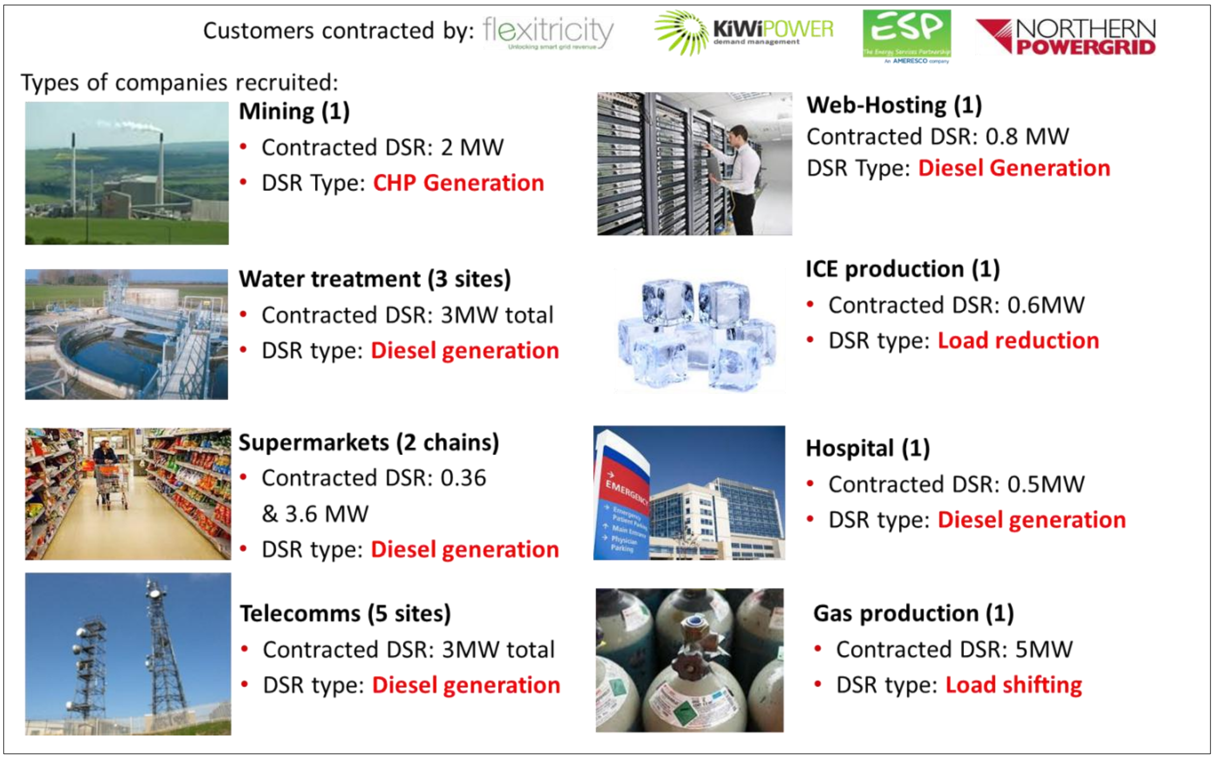


Figure 6.3: Participants in the 2014 I&C DSR trials

6.5 Commercial arrangements

Three contract structures were developed and two were utilised for the trials undertaken in 2012 and 2014, the full contract details of which can be found in the appendices of the respective trial reports.

- 2012 CLNR I&C DSR trials report
- 2014 CLNR I&C DSR trials report

For the 2014 trials, the agreement utilised for the 2012 trials was developed to include two additional validation methodologies together with a new payment type. In addition it was recognised that some of the definitions needed to be clearer and that a non-performance clause was missing from the agreement. This non-performance clause was added to clause 4 and sets out the process that must be followed if a site is declared unavailable.

Clauses that may need further amendment before these agreements can be utilised in a business as usual situation include:

- Clause 2 (Term and Termination) which currently states that the Agreement may be terminated by either Party upon one month prior written notice to the other Party. If DSR is to be utilised as business as usual one month's notice is unlikely to provide adequate time to find an alternative DSR provider.
- Clause 3 (Pilot Scheme) which gives a description of the trial and will need rewriting for business as usual application.
- Clause 4 (Demand Response Services) states that Sites shall not participate in the Short Term Operating Reserve scheme operated by National Grid Electricity Transmission plc for the same Availability Window as is used for this Agreement. This clause will need to be removed if the sharing of services with National Grid Electricity Transmission plc is to be pursued.
- Schedules 1, 2 and 3 will also need completing with details appropriate for a business as usual case.

6.5.1 Validation Methodology

For the spring 2014 trials three validation methodologies were developed for determining the DSR provided:

- Benchmarking
- Floor methodology
- 10 day average

For all three methodologies the following were agreed:

- Agreed Demand (MW) which is the amount of demand response to be provided by the site. The site is not paid any additional monies for providing more demand response that has been agreed.
- Response Time which is the maximum time in minutes which is permitted to elapse from the issuing of the instruction until the moment that the site provides the demand response.
- Instruction Maximum which is the maximum number of days each site must provide a demand response during the trial period. For these trials it was agreed that a maximum of 10 events would be called per site.
- Reporting Deadline which is the maximum time for providing metering data following an event. For these trials metering data was provided at the end of each month.

6.5.1.1 Benchmarking

To verify the performance of the site, this methodology takes the baseline as the power consumption for the metered half hour data immediately before the despatch instruction and compares that to the post-despatch consumption levels for the half hourly data during the DSR event. The difference between the two consumption levels is the delivered DSR.

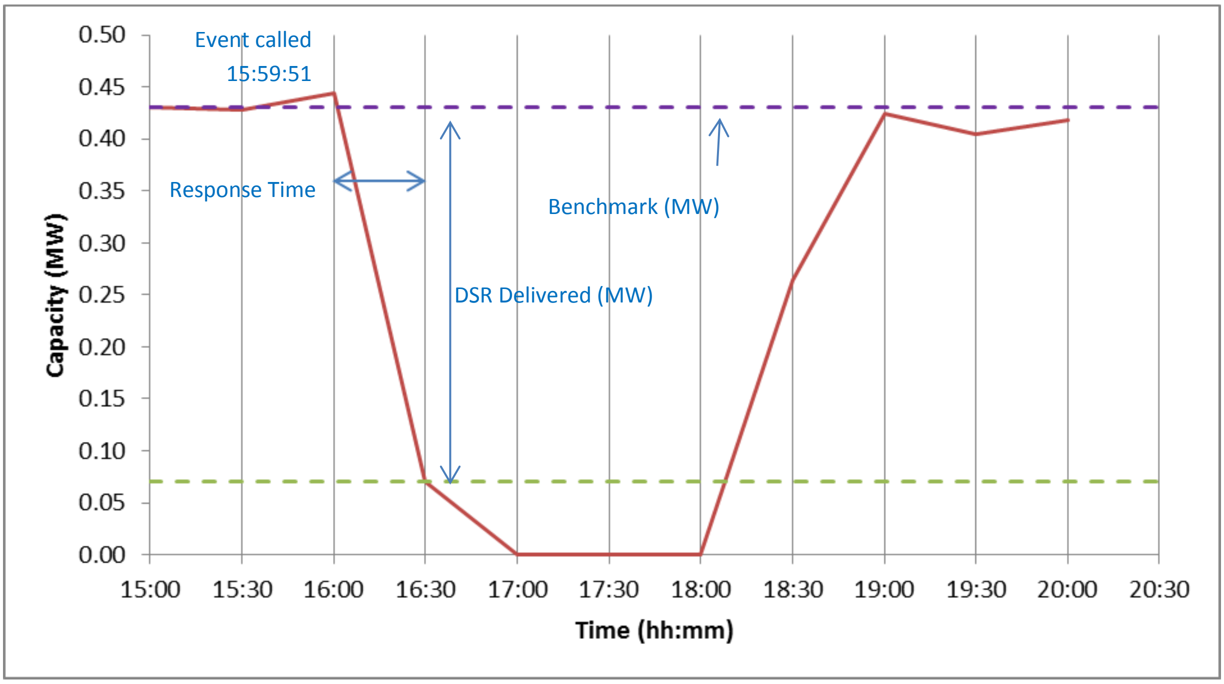


Figure 6.4: Benchmarking methodology

Figure 6.4 shows a site with an agreed DSR of 0.36MW and event duration of 2 hours. The DSR event shown in this diagram was called at 15:59:51.

Table 6.3 shows how the DSR would be verified for this event by subtracting the capacity in MW recorded at each half hour during the event from the benchmark of 0.43MW (the half hourly data recorded at 15:30). This data verifies that the agreed DSR of 0.36MW was provided for the duration of the event.

Time (hh:mm)	15:30	16:00	16:30	17:00	17:30	18:00
Capacity (MW)	0.43	0.44	0.07	0.00	0.00	0.00
DSR Delivered (MW)	N/A	N/A	0.36	0.43	0.43	0.43

Table 6.3: Half hourly data during DSR event

6.5.1.2 Floor methodology

This methodology requires the site to drop consumption below a threshold level during the DSR event. A “Floor” is agreed which the site must not go over during the DSR event. The DSR value which the site is paid to provide is calculated by subtracting the agreed Maximum Demand in MW during the DSR event from the agreed Average Demand calculated from the sites average consumption for the relevant time periods. The contract is verified by checking that the half hourly metered data during the DSR event is below the agreed floor level.

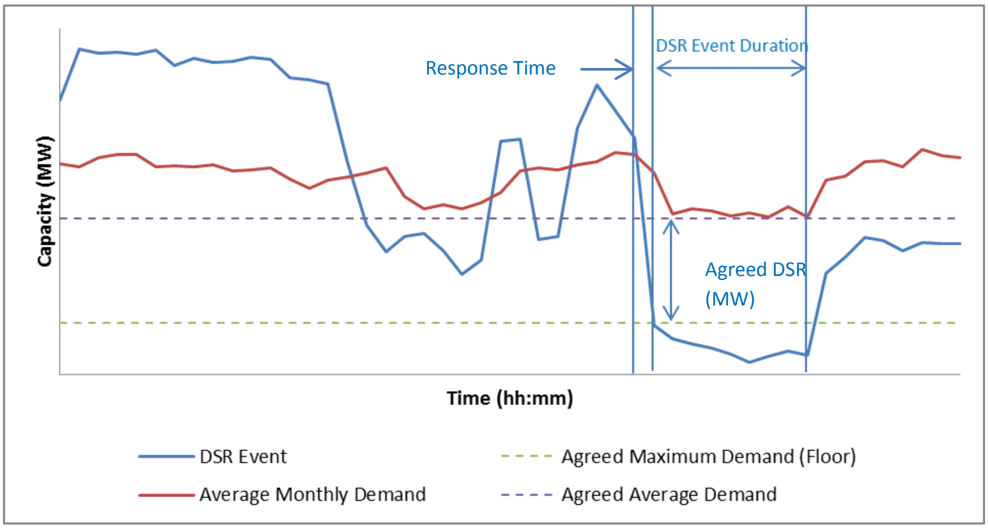


Figure 6.5: Floor methodology

Figure 6.5 shows a site with an agreed floor and demonstrates that the site did not breach this agreed maximum demand during the DSR event. This diagram verifies that the agreed DSR was provided for the duration of the event.

6.5.1.3 10-day average

For the 2014 trials a further baseline methodology was developed which is calculated by taking the average consumption from the previous 10-day period for the relevant time periods and comparing that profile with the post DSR instruction load profile. The difference is the DSR delivered. None of the sites chose to use this contract type for the trials. The reason given by the sites for not choosing this particular contract type was that they were satisfied with the verification provided with the benchmarking methodology and did not believe there was any additional benefit in utilising a 10 day average value.

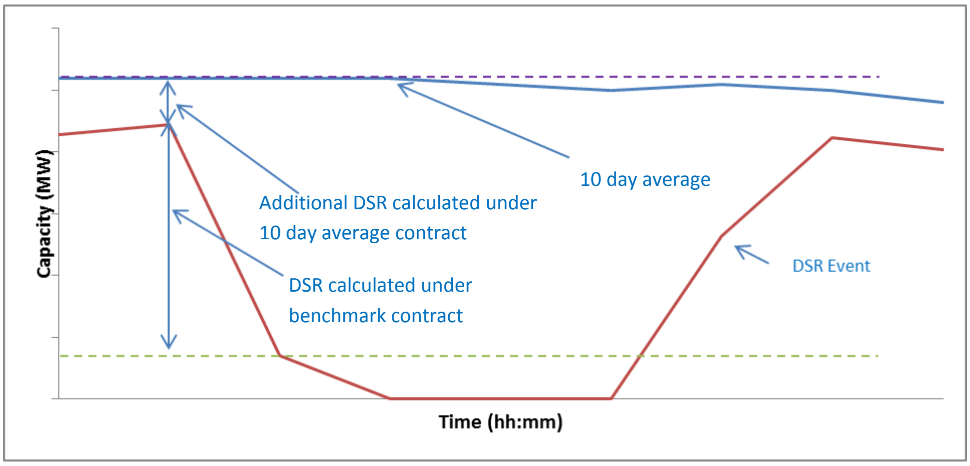


Figure 6.6: 10-day average methodology

Figure 6.6 shows that for this particular event, additional monies would have been paid had the site opted for the 10-day average contract rather than the baseline method.

6.5.2 Payment Structure

The payment structure used in the 2012 trials was based on the National Grid Short-term Operating Reserve (STOR) methodology, which uses an availability and utilisation component. In addition to this methodology, for the 2014 trials, a further option was developed which utilised a daily payment concept which removes the availability and utilisation structure. Although these payment structures could be used with each of the verification methodologies described in section 4.1, for the 2014 trials, the availability and utilisation payment structure was offered alongside the benchmarking and 10 day average methodologies and the daily payment concept was offered alongside the floor methodology.

6.5.2.1 Availability and Utilisation Payments

For the 2014 trials the availability and utilisation payment structure was utilised alongside the benchmarking methodology at ten of the fourteen sites. An availability price (AP_{sj}) of £10/MW/h and a utilisation price (EP_{sj}) of £300/MW/h was paid for the DSR services. The following formulae were used to calculate the availability and utilisation payments.

$$AF_{sm} = \sum_{j \in M_m} (AP_{sj} \times 0.5 hours \times CM_{sj})$$

Where AF_{sm} is the sum of all availability payments for each half hour in the availability window (3pm – 7pm), AP_{sj} is the availability price, in £/MW/h and CM_{sj} is the contracted DSR capacity, in MW.

$$UF_{sm} = \sum_{j \in M_m} (R_{sj} \times EP_{sj})$$

Where UF_{sm} is the sum of all utilisation payments for each half hour during the DSR event, R_{sj} is the DSR delivered, in MWh and EP_{sj} is the agreed utilisation price, in £/MW/h.

Availability Payment (AF) Worked Example
AP = £10/MW/h, CM = 0.36MW
AF = 10 x 0.5 x 0.36 = £1.80 per half hour or £14.40 per availability window (4 hours)

Utilisation Payment (UF) Worked Example
R = 0.18MWh, EP = £300/MW/h, no. of half hours during DSR event = 8
UF = (0.18 x 300) x 8 = £432

For a 45 day availability window and 10 events called, the maximum payment would be £4968 (£648 availability payment and £4644 utilisation payment).

6.5.2.2 Daily Charge

For the 2014 trials the daily charge payment structure was utilised alongside the floor methodology at four of the fourteen sites. The following formula was used to calculate the DSR payments.

Avoids admin involved with availability payments Sites have guaranteed revenue stream and are therefore incentivised to take part in DSR.

$$DF_{sm} = \sum_{d \in M_m} (DP_{sd} \times CM_{sd})$$

Where DF_{sm} is the sum of all the Demand Floor Payments for each half hour in the availability window (3pm – 7pm), DP_{sd} is the agreed Demand Response Price, in £/MW/day and CM_{sj} is the contracted DSR capacity, in MW.

Daily Charge Worked Example
DP = £306/MW/day, CM = 0.36MW
DF = 306 x 0.36 = £110.16 per day

For a 45 day availability window and 10 events called, the maximum payment would be £4957.20.

6.5.2.3 Comparison of Availability and Utilisation Payments v Daily Charge

It can be seen from the worked examples in section 4.2 and from diagram 4 that the trial was designed to pay the same to participants for 10 events called during a 45-day availability window, no matter which contract type they chose.

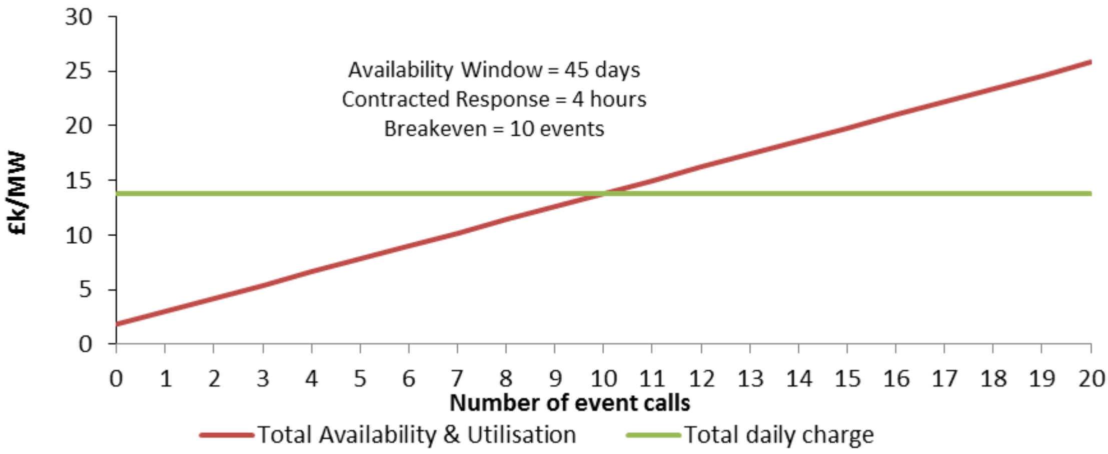


Figure 6.7: Comparison of Availability & Utilisation v Daily Charge for 2014 CLNR Trials

Table 6.4 shows the pros and cons of the two payment structures from both a DNO and a DSR provider perspective.

Payment Type	DNO perspective		DSR provider perspective	
	Pros	Cons	Pros	Cons
Availability & Utilisation	DSR availability was notified & visible each week Lower cost (if not called as often as predicted)	More complicated to operate and validate	Pays more if utilised more	Requires weekly notifications. Only the availability payment is guaranteed
Daily Charge	Simple to operate and validate Costs are fixed	Higher cost option (if not called as often as predicted) Availability notification was not a contract requirement	Simple - No availability notification required Guaranteed income to cover costs	No additional revenue if called more than the base case

Table 6.4: Comparison of payment types from DNO and DSR provider perspective

6.6 Trial operation and results

6.6.1 Event Initiation

For the 2012 trials, all the DSR events were simulated from the network perspective based on an event simulation plan. The DSR instruction was made via a telephone call from Northern Powergrid control rooms and the project team to the aggregator control rooms.

For the 2014 trials, all the DSR events were initiated automatically through the CLNR active network management system. This system consists of a network model which uses data coming in from monitored network equipment to identify and predict thermal and voltage constraints. It can then make intervention decisions based on the flexibility available from installed smart network technology or notified commercial arrangements with customers and it uses this information to then deploy the optimum solution to mitigate these constraints.

The details of the DSR providers were loaded into the active network management system and the signal to call the DSR was generated by simulating a forecast overload on the urban trial network transformers at Rise Carr Primary Substation by changing the set points on the transformer real time thermal rating (RTTR) model from 1,350 Amps to 275 Amps, during peak time.

Transformer real time thermal ratings (RTTR)[18] were calculated within the remote distributed controller (RDC)[19] with real time current and ambient air temperature analogues compared with previous readings. These analogues were used in the thermal modelling block of the RDC to determine the maximum current able to flow through the transformer within the next 30 minutes without causing the transformer to be thermally overloaded; this output was called the ampacity. Within the wide-area controller the ampacity value was compared with the actual current and when the actual load was greater than the RTTR value the transformer was forecast to be overloaded if the current was not reduced and hence a violation was seen and an intervention was instructed.

The CLNR ANM system was set up to check the network every 10 minutes. If a violation was observed, the controls options available were checked (in this case DSR) and commands sent. For the DSR a power reduction command was either sent to the aggregators, who then contacted the appropriate sites or to the site directly to initiate the DSR. Messages were automatically sent from the CLNR wide-area controller to the aggregator or customer. Information on the DSR contracts was held within the ANM system in two forms:

a) For communication via SMS a static, up-front declaration of availability was made;
b) For communication via Modbus a dynamic declaration of availability updated on-line in real-time was made.

In order to demonstrate that the system was able to choose which sites to call on a least cost basis a merit order, shown in Table 6.5, was added to the system. The merit order took in to account the size of the contracted DSR and the price. The price in the system did not reflect the actual

[18] This is a dynamic model, as it takes into account both recent and predicted future loading
[19] This is a part of the ANM system located at the primary substation to interface with the network equipment at the substation.

contractual costs but were amended to prove the technical concept of a merit order. The system then chose an optimum DSR provider based on cost by multiplying the MW available by the call duration available and by the DSR price in £/MWh.

Site	Provider Name	Interface Type	DSR MW	Availability Window start	Availability Window end	Call duration hrs	Price £/MWh	Merit Order
F	Aggregator 2	SMS	0.23	1500	1900	2	200	92.0
I	Aggregator 2	SMS	0.3	1500	1900	2	200	120.0
H	Aggregator 2	SMS	0.35	1500	1900	2	200	140.0
B	Aggregator 1	Modbus	0.36	1500	1900	4	200	288.0
G	Aggregator 2	SMS	0.97	1500	1900	2	200	388.0
N	Aggregator 2	SMS	1.05	1500	1900	2	200	420.0
J	Aggregator 1	Modbus	0.71	1500	1900	4	300	852.0
E	Aggregator 3	SMS	0.6	1500	1900	4	400	960.0
D	Aggregator 3	SMS	0.5	1500	1900	4	500	1000.0
K	Aggregator 1	Modbus	0.94	1500	1900	4	300	1128.0
M	Aggregator 3	SMS	0.8	1500	1900	4	500	1600.0
L	Aggregator 1	Modbus	1.4	1500	1900	4	400	2240.0
A	EHV Customer	SMS	5	1500	1900	4	200	4000.0
C	Aggregator 1	Modbus	3.6	1500	1900	4	300	4320.0

Table 6.5: Merit order in CLNR ANM system

The rest of this section concentrates on the operation and results from the 2014 trials.

6.6.2 Communications

To enhance the communication despatch protocols communication links were set up between the DNO, aggregators and I&C customer and the CLNR ANM system. These links allowed the ANM system to issue DSR instructions direct to the aggregators and I&C customer via SMS or Modbus[20]. The Aggregator had the facility to change the amount of DSR available during each contract period and the CLNR ANM system used the Modbus to send out requests for DSR stating the amount required.

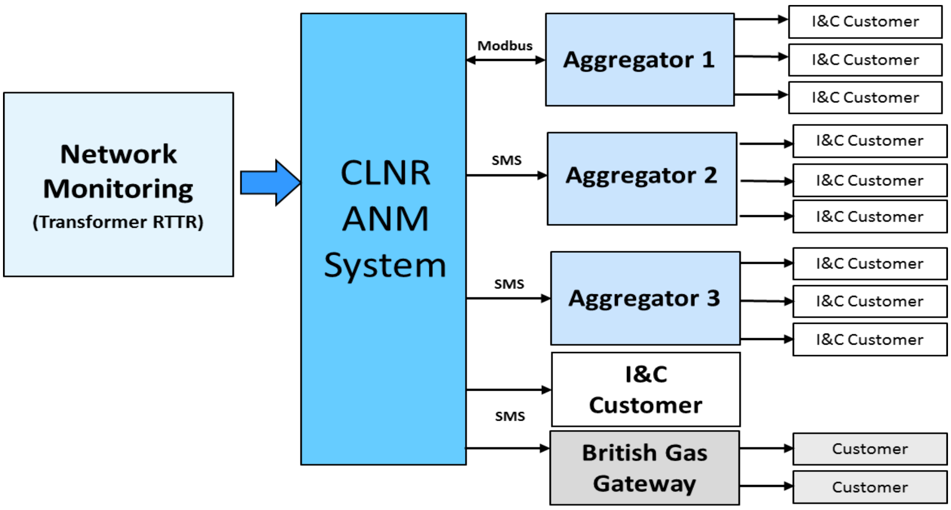


Figure 6.8: Integration of network monitoring & control to the DSR provider

[20] The Modbus is a serial communication protocol between two devices which allows the exchange of data between two control systems, in this case between the Aggregator and the CLNR ANM.

6.6.3 Monitoring & verification

Verification monitoring, to validate actual customer response, was completed in two ways:

a) Two way data from Modbus connection

b) Email or telephone confirmation that the site had responded.

Performance was verified by post event metering data. The settlement process was a manual activity and did require an iterative process to agree final positions with the aggregators. More development is required to produce a process that would be efficient on a greater scale.

6.6.4 Reliability

6.6.4.1 Availability

Both the Benchmarking and Floor contracts stated that Availability Declarations were to be made via e-mail by 10:00 am each Friday during the Availability Window. This declaration was to advise of the sites that were unavailable to provide DSR in the week immediately following the issue of the notice. The contracts also stated that if the site becomes unavailable after the declaration was made then such changes should be advised by e-mail as soon as reasonably practicable.

The trials were operated over a period of 25 weeks, although not all 14 sites were signed up for this period. Table 6.6 shows the availability of sites during the trials period. The maximum number of available declarations for the trials was 181 with a total of 87 weeks declared unavailable, giving a reliability of 50% for availability (100% for DSR via load shedding and 42% through the use of standby generation). Six sites were unavailable for the duration of the trials. Of these six sites, four were owned by a telecommunication company and were unavailable because they did not meet their acceptance test for participation in DSR. The other two sites were owned by a water company and both these sites developed generator engine faults during triad running and, because the generators are standby only, fault repairs were not a priority. The other sites with intermittent availability were due to communication problems between the site and aggregator.

Site	DSR Provision	Week Numbers																									Reliability
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	
A	Load																✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	100%
B	Generation	✓	✓	✓	✓	✓	✓	✓	✓	✓	×	×	×	×	×	×	×	×	✓	✓	✓	✓					62%
C	Generation	✓	✓	✓	✓	✓	✓	×	×	✓	×	✓	✓	✓	×	×	✓	✓	✓	✓	✓	✓					76%
D	Generation										✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓					100%
E	Load										✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓					100%
F	Generation																×	×	×	×	×	×					0%
G	Generation																×	×	×	×	×	×					0%
H	Generation																×	×	×	×	×	×					0%
I	Generation																✓	✓	✓	✓	✓	✓					100%
J	Generation	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×					0%
K	Generation	✓	✓	✓	✓	✓	✓	×	×	×	✓	✓	✓	✓	✓	×	✓	✓	×	×	×	×					62%
L	Generation	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×					0%
M	Generation										✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓					100%
N	Generation																×	×	×	×	×	×					0%
Load Reliability																											**100%**
Generation Reliability																											**42%**
Overall Trial Reliability for Availability																											**50%**

Table 6.6: Availability of sites during trials period

6.6.4.2 Utilisation

In total, 33 DSR instructions were issued across the portfolio, 31 instructions resulted in a successful DSR response giving a reliability of 94% for utilisation (100% for DSR via load shedding and 91% through the use of standby generation). The reason for the failed events was a diesel generator failure at Site I.

	Event	1	2	3	4	5	6	7	8	9	10	11	12	Reliability
Benchmark Availability & Utilisation	B			✓	✓		✓	✓	✓		✓			100%
	C			✓	✓		✓	✓	✓		✓			100%
	I	X	✓	X				✓	✓					60%
Floor Daily Payment	D			✓	✓	✓		✓		✓				100%
	E	✓	✓	✓	✓	✓	✓	✓	✓					100%
	A				✓							✓	✓	100%
Load Reliability														**100%**
Generation Reliability														**91%**
Overall Reliability														**94%**

Table 6.7: Utilisation of sites during trials

6.6.4.3 Combined Reliability

By multiplying the reliability figure for availability by the reliability figure for utilisation we can see the combined reliability figure of DSR for these trials. Table 6.8 shows the results when considering all the sites in the trials and gives a combined reliability figure of 47% (100% for DSR via load sheading and 38% through the use of standby generation).

Site	DSR Provision	Availability Reliability	Utilisation Reliability	Combined Reliability
A	Load	100%	100%	100%
B	Generation	62%	100%	62%
C	Generation	76%	100%	100%
D	Generation	100%	100%	100%
E	Load	100%	100%	100%
F	Generation	0%	N/A	N/A
G	Generation	0%	N/A	N/A
H	Generation	0%	N/A	N/A
I	Generation	100%	60%	60%
J	Generation	0%	N/A	N/A
K	Generation	62%	N/A	N/A
L	Generation	0%	N/A	N/A
M	Generation	100%	N/A	N/A
N	Generation	0%	N/A	N/A
Load Reliability		**100%**	**100%**	**100%**
Generation Reliability		**42%**	**91%**	**38%**
Overall Trial Reliability		**50%**	**94%**	**47%**

Table 6.8: Combined reliability of sites during the 2014 trials

However, if the sites that were declared unavailable for the duration of the trials are ignored in these calculations, then the combined reliability rises to 83% (100% for DSR via load sheading and 76% through the use of standby generation). This is a valid assumption as it was clear at the beginning of the trials that a number of the sites were not going to be able to offer the DSR service and this could be taken in to account in a business as usual situation by being selective in the sites that are signed to contract.

Site	DSR Provision	Availability Reliability	Utilisation Reliability	Combined Reliability
A	Load	100%	100%	100%
B	Generation	62%	100%	62%
C	Generation	76%	100%	76%
D	Generation	100%	100%	100%
E	Load	100%	100%	100%
I	Generation	100%	60%	60%
K	Generation	62%	N/A	N/A
M	Generation	100%	N/A	N/A
Load Reliability		**100%**	**100%**	**100%**
Generation Reliability		**83%**	**91%**	**76%**
Overall Trial Reliability		**88%**	**94%**	**83%**

Table 6.9: Combined reliability of sites during trials with some sites data removed

6.6.5 Customer Results

6.6.5.1 Generation Support

DSR customer B is a supermarket connected at HV, with a standby diesel generator utilised to provide DSR. Figure 6.9 shows the site response for a DSR event called at 15:40:27. The contractual response time of 20 minutes was easily achieved with the standby generator started at 15:43:28 and 0MW reached at 15:43:49. Load was reduced from 455kW to 0kW with 0.455MW of DSR provided, more than meeting the contracted DSR of 0.36MW. Load was restored at 17:48:19 with the run hour's cap of two hours being met.

- Customer B: Supermarket
- Contract Type: Benchmark
- Payments: Availability & Utilisation
- Contracted DSR: 0.36 MW
- Availability: 3pm – 6pm, Weekdays
- Run hours cap: 2 hours
- Response Time: 20 minutes
- Season: November – March 2014

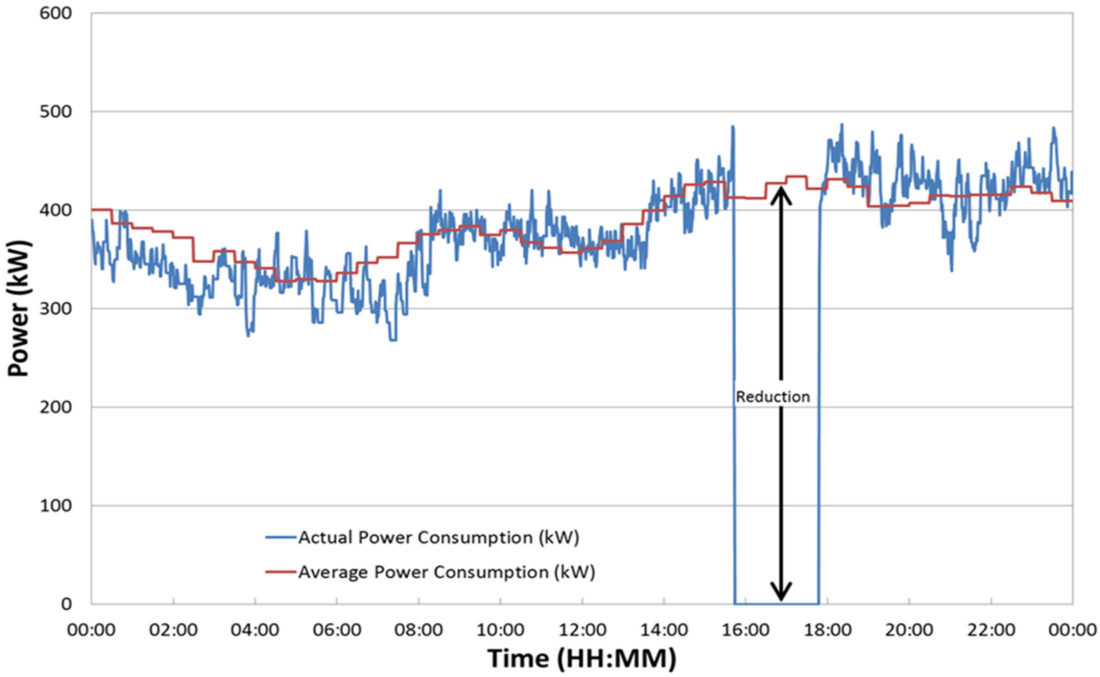


Figure 6.9: Load Profile for DSR Event provided by Generation Support

The site was paid approximately £200 for this event with an overall payment for participation in the trials of just over £2000 for 60 days of availability and 6 DSR events (£0.9k availability and £1.3k utilisation).

6.6.5.2 Demand Reduction

DSR customer E is a refrigeration company connected at HV, with DSR provided through load reduction. Figure 6.10 shows the site response for a DSR event called at 15:26:06. The contractual response time of 20 minutes was easily achieved with the floor reached at 15:33. The 1.65MW was breached at 19:15 with the contracted end time of 19:00 being met.

- Customer E: Refrigeration
- Contract Type: Floor
- Payments: Daily Payments
- Contracted DSR: 0.6 MW
- Availability: 3pm – 7pm, Weekdays
- Run hours cap: 4 hours
- Response Time: 20 minutes
- Season: February – March 2014

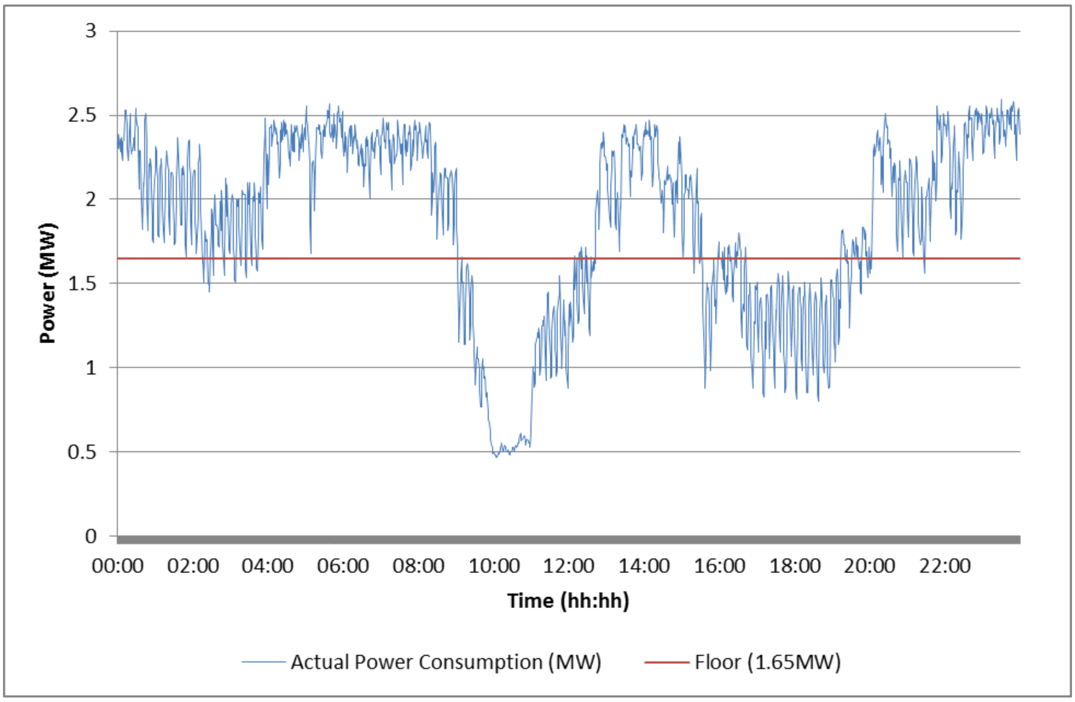


Figure 6.10: Load Profile for DSR Event provided through Demand Reduction

The site was on a daily payment contract and received approximately £180 per day with an overall payment for participation in the trials of just over £11,000 for 60 days of availability.

6.6.5.3 Demand Shifting

DSR customer A is a compressed gas supply company connected at EHV, its main demand is a motor which has a peak demand of approximately 10MW. The motor can be operated anytime during the day and as illustrated in Figure 6.11, during the DSR event the site has delayed starting the motor until after the availability window has ended. Although this site has the ability to provide 10MW of DSR, the I&C customer was willing to sign a contract paying for only 5MW. The site also had the capability to provide more than four hours availability as can be seen in Diagram 8.

- Customer A: Gas Production and Distribution
- Contract Type: Floor
- Payments: Daily Payments
- Contracted DSR: 5 MW
- Availability: 3pm – 7pm, Weekdays
- Run hours cap: 4 hours
- Response Time: 20 minutes
- Season: March – April 2014

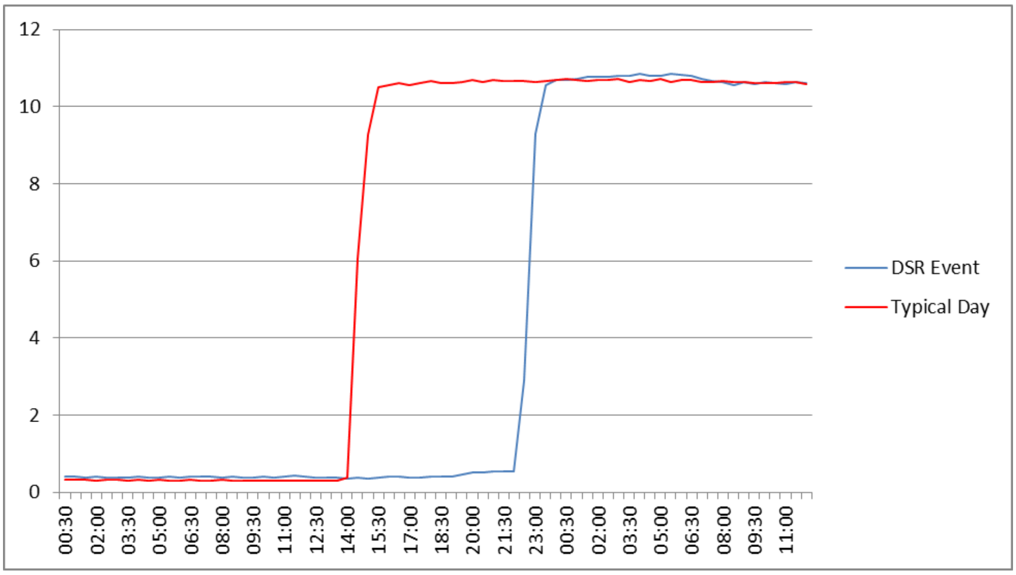


Figure 6.11: Load Profile for DSR Event provided through Demand Shifting

The site was on a daily payment contract and received £750 per day with an overall payment for participation in the trials of £36,000 for 48 days of availability.

6.6.6 Network Results

Figure 6.12 compares the load profiles during DSR event 6 for Customer E with that of the primary substation they are connected to. The DSR call was received at 15:16:42 and it can be seen that the demand at the customers site and at the primary substation both show a reduction after the DSR call. It can also be seen that when the event ends and the demand increases at the site there is a corresponding increase in demand at the primary substation.

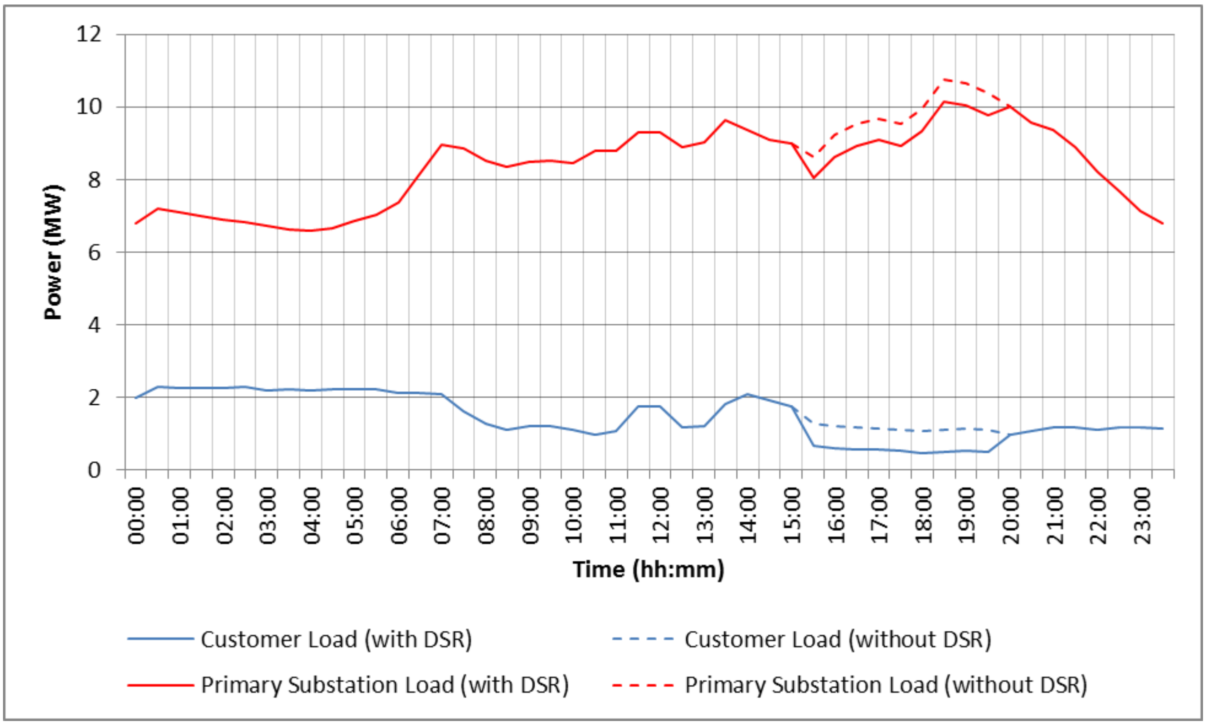


Figure 6.12: Load Profile at Primary Substation and Customer Site for DSR Event

Table 6.10 shows the reduction in demand at the Primary Substation and Customer site when the DSR event was called at 15:16:42. The table shows that a reduction in load at the customer's site contributes to a corresponding drop in the load at the primary substation, partially offset by load increases elsewhere on the network. It also shows an increase in load at 20:00 when the DSR event has finished.

Time (hh:mm)	I&C Customer Load (MW)	I&C Load Change (MW)	Primary Load (MW)	Primary Substation Load Change (MW)
15:00	1.766		8.997	
15:30	0.682	-1.084	8.033	-0.964
16:00	0.606	-0.076	8.633	0.6
16:30	0.578	-0.028	8.927	0.294
17:00	0.554	-0.024	9.081	0.154
17:30	0.52	-0.034	8.941	-0.14
18:00	0.468	-0.052	9.338	0.397
18:30	0.504	0.036	10.148	0.81
19:00	0.534	0.03	10.05	-0.098
19:30	0.512	-0.022	9.771	-0.279
20:00	0.988	0.476	10.022	0.251
20:30	1.078	0.09	9.576	-0.446

Table 6.10: Demand reduction at Primary Substation and Customer Site during DSR Event

6.7 Customer feedback

To gain feedback on the trials a series of interviews were carried out with trial participants which included both the commercial aggregators and the I&C customers. The detailed feedback from the interviews is given in Appendix D to the 2014 I&C trials report but a summary of the responses is as follows:

- All respondents were already participating in other DSR schemes such as STOR and TRIAD avoidance.
- The reasons given for taking part in the trials were to take advantage of the revenue opportunity and to support the development of the use of DSR by DNOs.
- As the trials participants were already taking part in other DSR schemes existing infrastructure was already in place. Therefore the only costs of participation were the fuel costs of standby generators or the rescheduling costs for load shifting.
- The contract terms were found to be relatively concise.
- One respondent listed the communication protocol as an issue and would have preferred a Modbus connection rather than an SMS.
- Respondents stated that any future DSR scheme must have a simple payment and penalty arrangement and must allow some flexibility and importantly needs to be aligned with the current National Grid demand side services.
- Aggregators found that standard DNO payment routines and timescales could be improved.

6.8 Key learning

These trials have proved that it is both operationally and commercially possible for DNOs to enter into DSR contracts with commercial aggregators and also directly with I&C customers. DSR could therefore be a real alternative to traditional system reinforcement. However, there are a number of factors that need to be taken into consideration when pursuing DSR as a business as usual solution:

It is possible to build an end-to-end active network management scheme to initiate DSR

- The trials have shown that it is possible to monitor the network sufficiently to identify constraints then automatically initiate and dispatch solutions to relieve those constraints.

The location of DSR provision in specific geographic locations will be difficult, requiring DNOs to improve engagement techniques to seek out and secure the DSR resource that is available

- DSR only provides an alternative to network solutions if sufficient willing providers can be found on the relevant parts of the system to make a large enough reduction.
- Our experience of recruitment for both the 2012 and the 2014 trials has shown that it is extremely difficult and time consuming to recruit customers in specific geographic locations.

- Our customer engagement research showed the feasibility of targeting specific geographic locations for the provision of DSR will be successful in some cases and not so in others but success could be improved with better customer information.

- Existing STOR participants were easier to recruit for a trial but it is currently not possible for providers to offer DSR to both National Grid and DNOs at the same time. The DNOs are effectively in a competitive market for DSR primarily with the National Grid STOR products but the development of sharing arrangements with National Grid will provide a means to identify and recruit this resource and facilitate a transition from trial to BAU.

- The DNOs can build effective relationships with both the aggregators and direct with I&C customers for the purpose of providing DSR products for DNO networks. DNOs require the infrastructure to manage these relationships, either in-house or via a third party such as an aggregator.

It is easier to procure DSR from standby generation than find a truly flexible load…

- 12 of the 14 trial participants in the 2014 trials provided the service via standby generation but we were successful in finding two effective and fast responding flexible loads. The first was provided by refrigeration plant operated by an ice manufacturer (0.6MW) connected at HV that was able to modulate its freezer load and the second was a gas compressor (5MW) connected at EHV that was able to defer a gas compression cycle.

- Standby generation appears to be the most successful entry point for an I&C customers wishing to participate in DSR schemes, as it provides a new revenue stream while minimising the number of changes and new risk to their business operation.

…but DSR reliability was poorer for standby generation meaning that DNOs need to over-procure to achieve the required level of network security

- The CLNR DSR contracts for the 2014 trials delivered an overall reliability of either 43% or 83% reliability, depending on how we include the sites that declared themselves unavailable for the whole of the trial.

- The overall availability was 50% for the trial period with 5 sites available for all of the trial period, 6 sites unavailable for all of the trial period and 3 sites with intermittent availability.

- The available DSR sites delivered a 94% success rate when instructed to deliver DSR; 100% from load reduction and 91% from generation substitution.

- Combining availability and utilisation, the 2014 trials have shown DSR provided through load reduction and load shifting to be more reliable than standby generation with a combined reliability of 100% (albeit from a smaller sample set) compared with 38% for DSR provided by standby generation.

- If we exclude the generator sites that notified themselves as unavailable for the whole trial period, the reliability from the generator sites rises to 76% and the overall reliability to 83%.

- The reliability is clearly less than 100% and the trial did not last for very long and so did not provide a measure long-term reliability which could be affected by a number of factors outside the control of the DNO. A probabilistic approach is therefore needed when planning, pricing and purchasing by applying a de-rating factor to account for combined availability and utilization reliability.

- DNOs would need strong performance clauses in the contracts but they will also need to over-contract in order to compensate for the availability and utilisation reliability, which would cost more and so potentially reduce the sums available to offer providers of DSR services.

- The sample size from CLNR is insufficient to accurately calculate the reliability factors that DNOs will have to apply, particularly for load reduction, but a better calculation may be possible when all LCN Fund project engaging in DSR have published their results (See Section 7 for other LCN Fund DSR trials).

- Locating customers that are willing to offer DSR for four hours in a day over a maximum 10-day period (potentially more than 10 days in some circumstances) will reduce the number of customers that feel able to participate in these schemes, particularly for load reduction. A solution to this issue could be to use a portfolio of customers to deliver the DNO's requirements. This approach opens the potential to reduce the obligations for the DSR provider which in turn could create a larger pool of customers for the DNOs from which to recruit DSR providers.

The contract arrangements need to be simple to understand, simple to operate and they must offer a fair price to both the provider and the DNO in order to be viable

- Customers that are already participating in STOR are a natural first choice for recruitment, provided that sharing arrangements[21] can be established, as they are already knowledgeable about the concepts of DSR. This makes establishing the contracts a much more straight forward process.
- Customers found the CLNR contract terms relatively concise and easy to understand, particularly when compared to other DSR schemes.

- For future DSR schemes, customers would like a simple payment and penalty arrangement which allows some flexibility and for it to be aligned with the current National Grid demand side response schemes.

- Aggregators found that standard DNO payment routines and timescales could be improved, requiring consideration of a more streamlined verification and payment procedure.

- Customers were willing to accept arrangements based on STOR prices for the trial but business as usual pricing will be driven by a number of factors. DNOs will need to consider the deferred / avoided reinforcement costs, response reliability, the level of benefit sharing between the DSR

[21] Customers had to temporarily drop out of STOR for the duration of the trial

provider and all customers[22] whilst recognising that DSR providers are looking for bankable business cases.

- The CLNR contract templates used in CLNR provide examples of DSR contracts that have worked. Further work is needed to evaluate whether different contracts / pricing structures might be preferable for different situations.

- The time required to finalise the legal framework for DSR products is material. The key activities can be split into three areas. This process can take up to 4 months. This time should reduce as counterparties and DNOs become familiar with the contract structures although in the early years there is a high probability that the process will always have new customers unfamiliar with DSR to accommodate.

Transition to business as usual will require a significant resource commitment

- The knowledge transfer process from the project to the DNO's operational teams will involve a significant resource commitment. The following areas will be involved:

  - Asset management network planning. Actively managed DSR is not currently a tool at the disposal of network engineers; a process is required to transform DSR from a concept to a real option for network planners.
  - Network control. The network control engineers monitor the network and react in real time. The introduction of DSR in the control room will require robust systems, processes and training for the network engineers.
  - Commercial teams. The requirement for customer facing or front office resources will depend on the market entry model selected. However, as noted above in the I&C customer engagement section there is merit in the DNO taking responsibility for the first contact with customers and this could be taken further to include aggregator activities. Our views on the model will evolve as the CLNR project progresses.
  - Support or back office teams. DSR contracts will require a resource impact on staff in the functions of procurement, settlement, legal and commercial.

[22] Current incentives in the IQI sharing mechanism drive DNOs to try to deliver as much benefit as possible to other connected customers

7 Overview of other DSR trials and services

The projects listed in Table 7.1 have trialled DSR with I&C customers as part of the Low Carbon Networks (LCN) Fund:

Project / DSR trial	Distribution Network Operator	LCN Tier
Customer-Led Network Revolution	Northern Powergrid	Tier 2
Honeywell I&C Automated Demand Response	SSEPD	Tier 1
New Thames Valley Vision (NTVV)	SSEPD	Tier 2
Flexible Approaches for Low Carbon Optimised Networks (FALCON)	Western Power Distribution	Tier 2
Low Carbon London (LCL)	UK Power Networks	Tier 2
Capacity to Customers	Electricity North West	Tier 2

Table 7.1: LCN Fund DSR Projects

7.1 Key learning points from all DSR trials and services

A review of the outputs from other LCN Fund projects shows that:

- There is a consensus that DSR services can be utilised by Distribution Network Operators (DNOs) to manage network constraints;
- Generation-led DSR response is likely to contribute the bulk of the DSR response to UK DNO's in comparison to demand reduction. This can be corroborated by the results from the FALCON and CLNR project, where as part of the trials, the generation-led DSR response equated to 100% and 63% respectively;
- The potential for demand reduction from HVAC systems in commercial buildings will be greatest in the summer peaks and limited during the winter peaks. The reason for this is that the majority of demand response in this trial was provided by the modification of HVAC loads. The HVAC demand at any time is driven by the building heat/cooling demand, which in turn depends on the outside weather conditions. Consequently, the largest amount of controllable load may be present in summer (i.e. when cooling load is greatest) rather than winter. This has the potential to impact on the use of this type of DSR to carry out peak shaving/defer reinforcement on substations where the greatest demand occurs in winter. The level of demand response which can be achieved will also depend on the length of event; a short interruption to certain loads may be feasible (without compromising comfort or operations) whilst a longer interruption is not possible. Future ADR trials will determine the available demand response from various systems including chillers and air handling units (AHU) and the impact of this reduction in load on comfort levels. In summary, the type of network (summer or winter peaking) needs to be taken into account when procuring DSR services for specific substations;
- Customers will need to be incentivised for large scale DSR deployment and the level of incentive required will be driven by the level of cost savings likely from deferred or avoided investment at a particular location, the level of market interest and the level of benefit (£) that can be derived from each individual DSR scheme;

- The time and resources required to engage with customers to procure DSR services should not be under-estimated. Experience from CLNR has shown that the lead times from making initial contact with a customer to finalising a DSR contract can easily take a year or more;
- The current regulations relating to the 'Security of Supply' (which mandate compliance with P2/6 and ETR130) do not provide specific information on how DNOs should assess the contribution of DSR. The Capacity to Customers project has made some high-level recommendations for changes to ETR130 but recommends leaving the method of calculating the reliability of the DSR to the DNO. Therefore the reliability of DSR services needs to be taken into account when procuring DSR to ensure that 'Security of Supply' is maintained;
- Flexible DSR contracts are required to maximise the potential DSR response. This is confirmed by the approach taken by National Grid for Short Term Operating Reserve (STOR) contracts. This requirement has led to the evolution of the STOR service into the current forms (Committed, Flexible and Premium Flexible); and
- The reliability of DSR services reported in the DSR trials to date ranges between 43% and 85%, depending on how the performance of providers that declared themselves unavailable for the duration of the trials is taken in to account. These reliability figures are derived from experience from trialing DSR on LCN Fund projects and the STOR service. Whilst generation led responses are more prevalent, the demand led DSR services provided a more reliable response across the trials. The performance of generation response is likely to improve as more customers see DSR as a means of keeping their assets in good operational condition.

7.2 DSR trial common themes and differences

The following tables provide an overview of the DSR services trialled by LCN Fund projects.

Project/DSR Trial	Status	Commercial Customers	Demand Led DSR	Generation Led DSR
Customer-Led Network Revolution	Complete	Yes	Yes	Yes
Low Carbon London	Complete	Yes	Yes	Yes
FALCON	On-going	Yes	Yes	Yes
Capacity to Customers	On-going	Yes	Yes	Yes
New Thames Valley Vision	On-going	Yes	Yes	Yes

Table 7.2: LCN Fund DSR Trial Status & Type

Table 7.2 shows that the DSR trials for each project are at different stages, with two projects having completed trials and three projects with on-going trials. All the projects have targeted I&C customers seeking a response by either demand or generation led DSR services.

Table 7.3, below, shows that:

- Overall DNOs have contracted DSR services primarily through aggregators;
- Incentives have been offered in order to sign up DSR customer with the exception of the New Thames Valley Vision project;
- There is a significant variation in the structure of the incentives offered; and

- DNOs have sought to trial new types of contracts as part of the trials.

Project/DSR Trial	Aggregator or Direct	Availability/ Utilisation	Alternative Payment Mechanism
Customer-Led Network Revolution	Primarily Aggregator	£10/MW/h and £300/MW/h	£306 per MW per day HV £150 per MW per day EHV
Low Carbon London	Primarily Aggregator	£50 to £100/MW/h and £200/MW/h	N/A
FALCON	Primarily Aggregator	N/A	Hourly Utilisation rate (£ per MWh) calculated by dividing the annual DSR budget per MW by the total annual duration of expected DSR operation
Capacity to Customers	Direct & Aggregator	N/A	Utilisation only at £300/MW/h
New Thames Valley Vision	Direct	N/A	N/A

Table 7.3: LCN Fund DSR Trial Incentives

Table 7.4 below shows that:

- The business drivers for implementing DSR for the trials are similar; however, the dispatch trigger for DSR services varies. The pre or post fault dispatch of DSR services is likely to have a significant impact on the business case of DSR services (in terms of the number of DSR calls);
- The dispatch notice period for DSR services is typically between 20 and 30 minutes, however, it should be noted that generation-led DSR services has the potential to provide a much quicker response (<3 minutes) if automated;
- The duration of the DSR call varies from one project to another (1 to 8 hours) this reflects the fact that the duration of DSR services will be driven by the shape (profile) of the substation load and the capacity of the substation; and
- The reliability of DSR service varies depending on the ability of the DSR customer to respond to the DSR call. This has significant implication for 'Security of Supply'.

Project/DSR Trial	Dispatch Trigger	Dispatch Notice Period	DSR Response Duration	Reliability
Customer-Led Network Revolution	**Post Fault** via a signal from Enhanced Automatic Voltage Control (EAVC), Real-Time Thermal Rating (RTTR) or both.	15 to 20 minutes	2 to 4 hours	Between 43% and 83%
Low Carbon London	Designed to relieve **network constraints** when network load was at its peak	30 minutes (2 sites <3 mins)	1 to 3 hours	Between 58% and 76%
FALCON	**Pre-fault** scenario, i.e. to ensure that demand remains within an assets rating	30 minutes	1 to 2 hours	66% (on average)
Capacity to Customers	Capacity of either existing customers or new connections to be managed **under fault** or abnormal system conditions	Post fault	2 to 8 hours	N/A[23]

Table 7.4: LCN Fund DSR Trial Characteristics

[23] This is a post-fault product where the flexibility offered is being restored by the DNO when the sufficient capacity is available.

8 I&C Ancillary Services – Voltage Support

8.1 Purpose of the research

Any new power flow will affect existing voltage and thermal constraints. Where new generation offsets existing load (and vice versa) it will tend to ease constraints. However, generation sometimes more than offsets existing load, creating a reverse power flow.

The main way in which distribution networks can be considered to be unidirectional is in voltage control. The permissible voltage limits have been allocated on the assumption that power flows only towards customers. Therefore, reverse power flows will often create voltages above legal limits. That is, networks are designed to run at maximum permissible voltage at minimum expected demand and minimum permissible voltage at maximum expected demand. As soon as generation reverses the power flow or even reduces net demand below the design level, legal voltage limits will be exceeded.

Present network design is to limit the generator capacity to the level at which the upper limit is not exceeded with maximum generation and minimum load.

With the expansion of generation, voltage rise will become a significant constraint for both DNOs and generators in terms of securing the network reliability and maximising the power output.

DNOs normally request generators to either be capable of operating within a specific range of power factor or to operate at a fixed power factor. This requirement is based on the characteristics of the network and aims to keep voltage profiles within limits but if voltage excursions occur the generator may have to be constrained off. Such operation can also be inefficient with respect to increasing network losses.

Generators are however, capable of providing voltage support by injecting or absorbing reactive power. This will mean that there will be times when the generator will not operate close to or at the nominal power factor in the connection agreement; however this is a trade-off between potentially reducing active power export over a relatively short period and enabling higher generation capacity and energy production in the long term.

The CLNR project took the opportunity to trial this mode of operation with a wind farm that was required to have this capability due to grid code requirements for generators of this size.

8.2 Background

Modelling showed that the installation of 74MW of generation into Northern Powergrid’s Linton 66kV network would result in unacceptably high voltages for low voltage customers supplied from Denwick 66/22kV substation.

Middlemoor 54MW wind farm and Wandy Law 20MW wind farm are connected to the Linton 66kV network in the Northumberland area via a 26.5km double circuit to our Denwick substation and then by a 13km single circuit to the Middlemoor site. The schematic for the network is shown in Figure 9.1 below. Linton substation is ultimately connected to Blyth 275/132kV Grid Supply Point via a double circuit 132kV tower line.

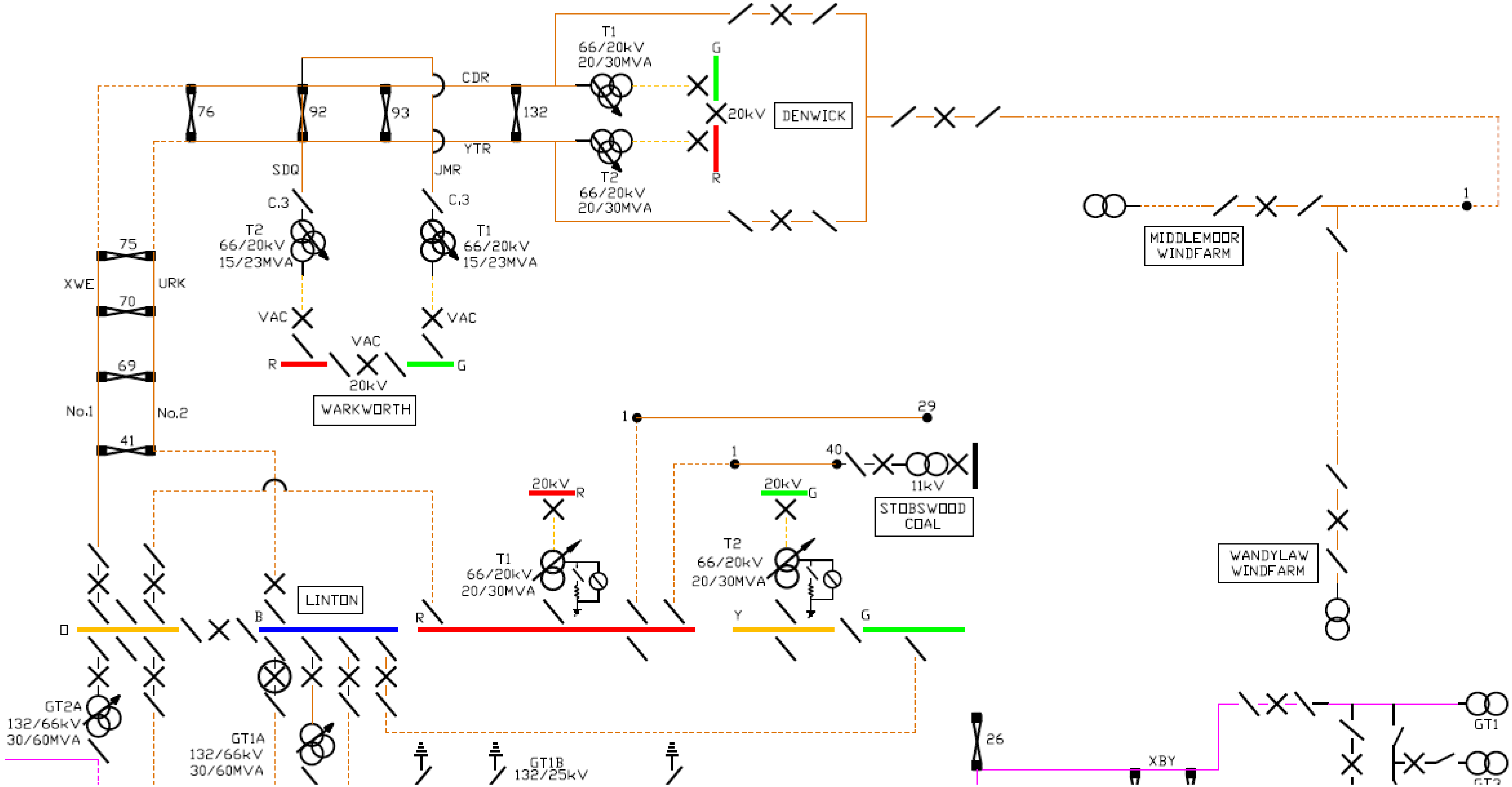


Figure 9.1 132kV / EHV network connecting Middlemoor and Wandy Law wind farms

Initial design studies identified that at times of minimum network load and maximum generation export the voltage control scheme at Denwick substation would not be able to adequately lower the voltage on the Denwick 20kV bar. The tap changers on the Denwick 66/22kV transformers would reach their last tap, at which point the voltage on the Denwick 20kV bar would exceed the design limit and customers connected at LV would see voltages at their point of supply above the statutory limit of 253V.

Northern Powergrid normally require generation customers to operate with a power factor in the region of 0.95 lagging to unity, which equates to producing both real and reactive power when in the generating mode. Generating with a lagging power factor generally provides voltage support to a network, leading to an increase in the measured voltage at the point of generating. On this particular network having Middlemoor and Wandylaw operating with a lagging power factor increases the voltage at Denwick, which exacerbates the voltage rise problem on the Denwick 20kV and LV network.

8.3 Method - voltage control mode

Middlemoor 54MW wind farm, having a capacity between 50MW and 100MW, is classed as a "Medium Embedded Power Station" (MEPS) and is therefore subject to a Grid Code compliance requirement to have a reactive power capability covering both lagging and leading power factors and also to operate in voltage control mode[24], whereby the amount of reactive power output is a function of the voltage at the point of supply rather than the amount of real power being generated. This facility is historically used by National Grid to manage the voltage on the 275kV and 400kV systems.

Middlemoor wind farm is the first MEPS to be connected to the Northern Powergrid network, where it does not connect into the same network voltage as that which is at the GSP (i.e. 132kV in this case). Operating Middlemoor wind farm in voltage control mode will not have a direct impact on voltage support for the National Grid system, as the voltage control system on the Linton 66kV network will compensate for voltage depressions on the higher voltage system, thus de-linking Middlemoor from the operating conditions of the National Grid system.

Our design studies looked at the potential voltage rise on the network at minimum and maximum demand, with the wind farms operating at maximum output. We set Wandylaw wind farm at unity power factor and varied Middlemoor wind farm power factor across the range 0.95 lag to 0.95 lead.

The results of the studies were normalised to give a voltage of 66.0kV at Linton, where the busbar voltage is controlled by the tap-changers on the 132/66kV transformers. Normalising the results removed any potential errors introduced by the dead band in the voltage control scheme at Linton.

The graphs in Figure 9.2 (a) and 9.2 (b) show the impact on voltage at varying point on the network as a result of varying the reactive power output from Wandylaw wind farm.

[24] Also referred to as PV mode.

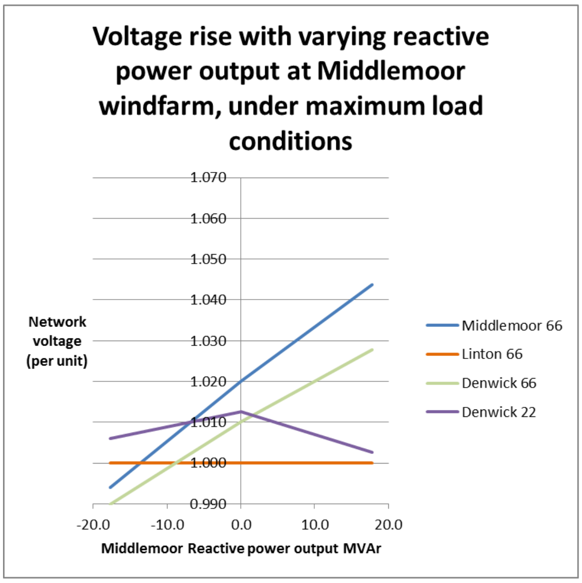


Figure 9.2 (a) Volts at maximum load

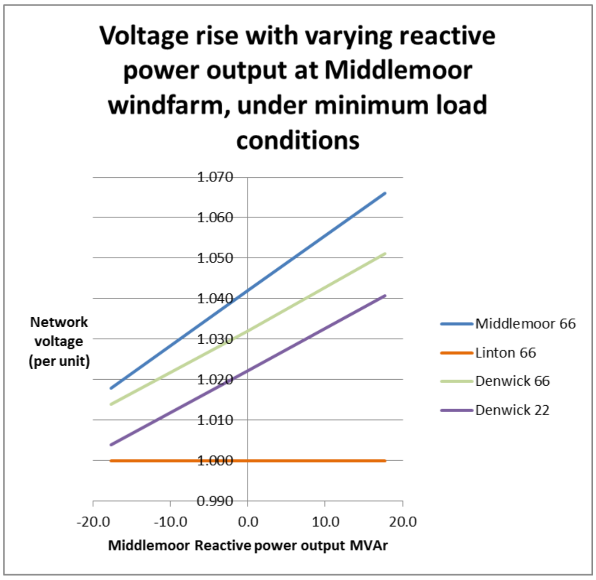


Figure 9.2 (b) Volts at minimum load

As the voltage at Linton is being held at 66.0kV (1 per unit), the voltage on the 66kV network at Middlemoor and Denwick increase with increasing reactive power export at the wind farm. Without any voltage control on the Denwick 20kV system this voltage would also rise. However the voltage control scheme on the 66/22kV transformers compensates for the high voltage on the 66kV network and maintains the 20kV network in the region of 1.01 per unit. This can be seen in Figure 9.2 (a). Under these circumstances the reactive power output of the wind farm does not have a significant impact on the voltage.

Under minimum demand conditions there are no taps left on the Denwick 66/22kV transformers, so the voltage control scheme is no longer able to compensate for the increasing voltage on the 66kV network. Hence, the voltage on the 20kV network increases, as shown in Figure 9.2 (b). With a leading power factor of 0.95 it is possible to hold the Denwick 20kV bar to 1.004 pu. As the reactive power being imported at Middlemoor reduces, the voltage at Denwick rises.

To protect customers from unacceptably high voltages a simple scheme was installed to trip off the wind farms if the voltage on the Denwick network exceeds statutory limits. While this scheme protects customers from over-voltage it leads to the curtailment of wind farm output.

The above analysis shows that there is no network requirement to actively manage the voltage at Middlemoor when the network is operating at maximum demand, but there is a very clear need to manage the voltage at minimum demand if the wind farm does not want to be curtailed.

A simple solution would be to ask the wind farm to permanently operate at a leading power factor. The tap changers at Denwick have the necessary range to manage the associated voltage range on the 66kV network but absorbing VArs at times of high demand increases network losses and is therefore inefficient.

A more sophisticated solution would be to vary the reactive output from the wind farm as the demand on the network changes and as the real power output from the wind farm changes. Measurement of these two values and the associated algorithm to determine the required level of reactive power output is not overly complex but would require additional communications to pass the remote demand readings to the wind farm.

Using the voltage at the point of supply to the wind farm to determine the amount of reactive power to inject or absorb is a much simpler scheme. With careful selection of the voltage set point and the amount of reactive power injected per unit change in voltage (the gradient), a good balance of reactive power can be achieved, which will give reasonable optimisation of losses.

Further design studies were undertaken out to determine an initial voltage set point and gradient to allow Middlemoor wind farm to run in voltage control mode. With a set point of 65.5kV and a gradient of 3% the studies showed that the voltage at Middlemoor will not exceed 1.03pu, which ensures that the voltage at Denwick stays within limits.

The following graphs in Figure 9.3 (a) and 9.3 (b) show the reactive power performance requirement for the voltage control scheme. The point at which the Middlemoor 66kV voltage profile crosses the performance line is the settling point for the voltage control. Hence, under minimum load conditions with maximum generation the voltage at Middlemoor will rise to 1.02pu, while at maximum load it will only rise to 1.01pu.

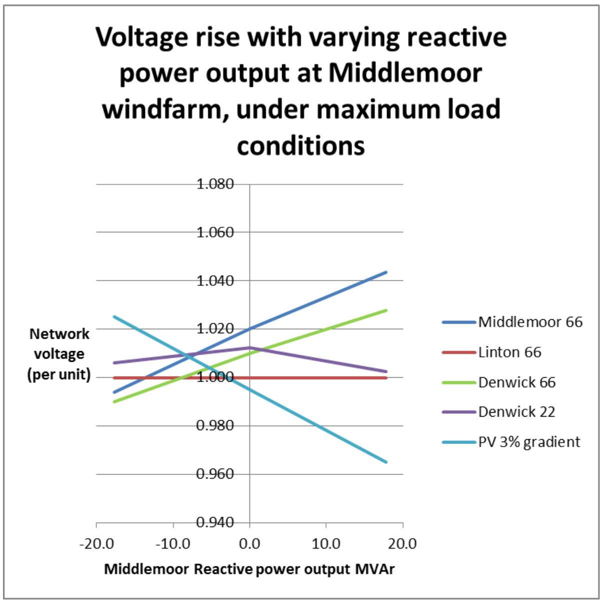


Figure 9.2 (a) Volts at maximum load

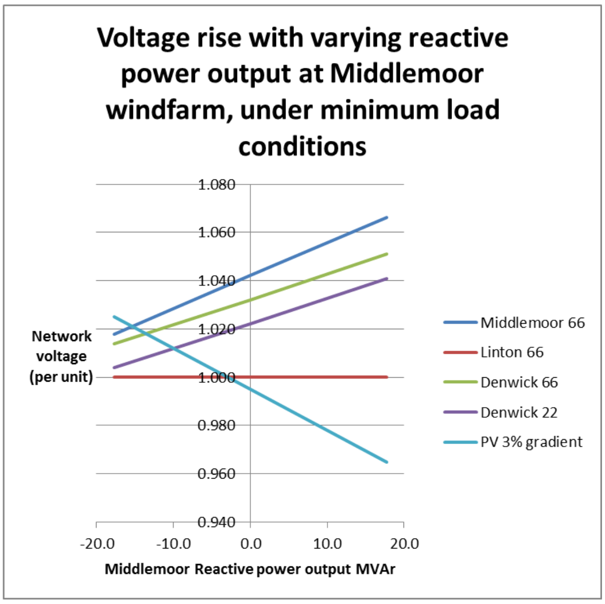


Figure 9.2 (b) Volts at minimum load

8.4 Results

Middlemoor wind farm began operation in January 2014. Below is a graph of their reactive power output plotted against the local network voltage for two different times of day over a 2 month period. The data used is average half-hourly data from operational metering. It is assumed that the offset of reactive power output compared to the compliance line, which represents the system settings, is due to the averaging of the values over the half hour period.

Prior to application of the voltage control settings the wind farm was operating close to unity power factor. Figure 9.4 shows the resulting voltage rise without operating in voltage control mode where it can be seen that the wind farm was operating at unity power factor and the voltage ran as high as 69kV.

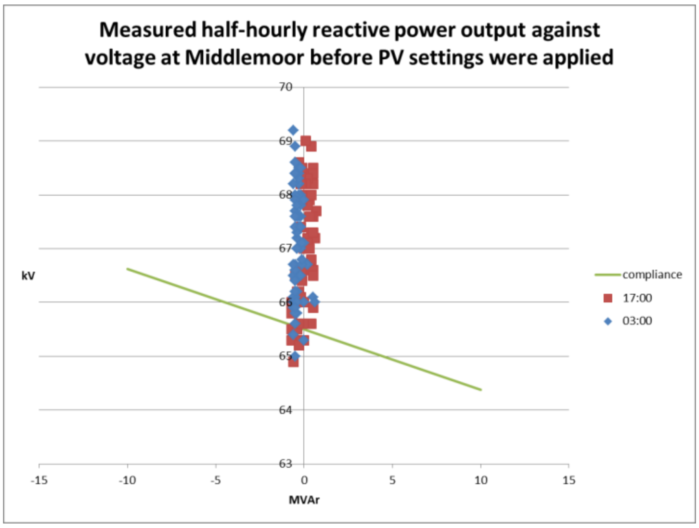


Figure 9.4 Reactive power output before Voltage Control Mode applied

Figure 9.4 shows the resulting voltage rise without operating in PV mode.

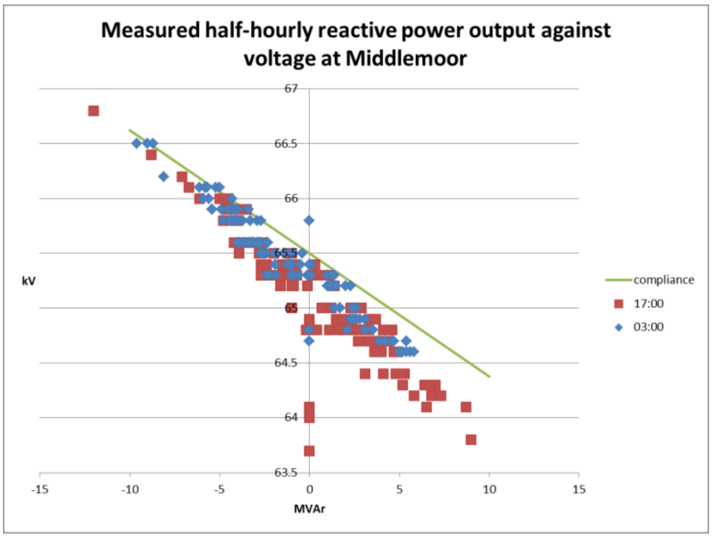


Figure 9.4 Reactive power output in Voltage Control Mode

Operating in Voltage Control Mode has successfully reduced the maximum voltage on the network from 69.1kV down to 66.8kV. However, the voltage set point at Linton on the 66kV system was simultaneously lowered from 66.0kV to 65.5kV, so the true benefit of the PV mode is from 69.1kV to 67.3kV. There were no occasions when the generation needed to be constrained off.

8.5 Recommendations

In 2015, after 12 months of operation, the settings will be reviewed to ascertain whether the optimum setting has been achieved taking into consideration the voltage profiles on the network and the real and reactive power flows. A decision will then be made on how best to take this forward into our policy for the connection of intermittent generation and whether this mode of operation will be offered to generators that are able to operate in voltage control mode as an alternative to constraint.

Further work is also recommended to investigate how two generators operating in PV mode on the same network might interact with each other and to what extent their set points and operating gradients would need to be co-ordinated. Standard half-hour sampling periods are unlikely to provide the necessary level of detail to understand how two sites might interact. Therefore shorter sampling periods will be required to undertake this piece of work.

Consideration also needs to be given to the design tools used by the network operator. Not all load flow analysis tools correctly model generators operating in PV mode. The designer will need to carry out additional studies to ascertain whether a generator should operate in PV mode or in a more traditional PQ mode (fixed power factor).

9 Conclusions

9.1 Summary of key findings

9.1.1 Static demand-side response - Impact of the 2010 tariff reform (Test Cell 7)

Analysis has shown that the introduction of the CDCM Red/Amber/Green time bands in 2010 has not had a noticeable effect on the number of units consumed by industrial & commercial (I&C) customers in Yorkshire and the Northeast during peak load periods.

This finding is based on Durham University's analysis of individual customer consumption records and backed up by Northern Powergrid's high-level analysis of overall consumption between price bands, which have shown that the proportion of electricity consumption between bands has remained broadly constant since 2010. This could be due to a number of reasons:

- the underlying distribution use of system (DUoS) tariff not being visible in all the Suppliers' tariff offerings;
- Customers preferences for the certainty and lack of complexity of a flat tariff; and
- the nature of the I&C load profile which does not have an evening peak and actually starts to fall away from 16:00 onwards.

From a survey of Suppliers we found that only a small percentage of customers see price signals that encourage peak avoidance and the Suppliers fed back that they would not wish to see the pass through of the DUoS pricing to be mandated.

However, in order to capitalise on the potential for a shift of consumption from the red band to the amber / green bands it is recommend that Suppliers give enhanced visibility to the benefits of peak pricing in some of their tariffs to enable half-hourly metered customers to benefit from the cost signals that they provide if they so choose.

Such a move would provide additional incentive for I&C customers to permanently reduce load during peak load periods or would deliver additional value to those that wish to provide dynamic ancillary services such as load reduction or standby generator response.

9.1.2 On-demand demand-side response - Responsive load & generation trials (Test Cell 18)

Sixteen I&C customers participated in the CLNR DSR trials in 2012 and 2014 during which different methods of recruitment, different contract and payment arrangements were trialled and different methods of sending the DSR signal. The key conclusions are as follows:

I&C DSR gives the DNO potential to defer or avoid primary network reinforcement investment

- I&C DSR should *always* be considered as an option to address forecast network constraints and a ceiling price can be calculated based upon the price of the lowest cost alternative;
- The main use case to be adopted by Northern Powergrid in the RIIO-ED1 period is likely to be a post-fault response to manage the security of supply at forecast EHV constraint points (i.e.

primary substations forecast to be occasionally over-firm during the winter evening peaks). It may be activated following a fault on the network that either occurs during, or cannot be restored before the onset of, the winter evening peak.

- Traditional reinforcement tends to provide capacity in discrete blocks which might sometimes be greater than what is actually needed. DSR provides the option to secure relatively small increases in capacity to meet the forecast demand and the amount of DSR capacity contracted each year can be amended up or down depending upon the actual load growth experienced and the DSR capacity available.

- DSR provides the option for DNOs to continue to defer reinforcement until a point is reached when no further capacity can be purchased to meet the forecast load growth.

- In some cases, DSR can eliminate the need for reinforcement altogether, and hence prevent sunk costs, if the actual load growth turns out to be less than that forecast. DSR contracts can be cancelled if the need goes away and so it provides a significant “option” value.

The location of DSR provision in specific geographic locations will be difficult, requiring DNOs to improve engagement techniques to seek out and secure the resource that is available

- Locating customers that are willing to offer the level of DSR response required by DNOs is difficult. The frequency of call off is likely to be low but, when it is required, it could be for four hours a day and be needed for potentially more than 10 days in some circumstances – until normal capacity is restored. This will reduce the number of customers that are capable or willing to can participate in these schemes unless there are sufficient providers to allow the response to be sequenced around the available resource.

- When targeting a tight geographic area the initial customer drop-out rates can be high due to issues with contacting the sites, contacting the right person at the site, the size of a site’s flexible load / generation and the nature of the service required. Significant work is required to improve a DNO’s knowledge of its customers to enable more efficient targeting but also to increase the knowledge of DSR amongst customers.

- We have found that the DNOs can build effective relationships with commercial aggregators for the purpose of providing demand side response (DSR) but we also engaged directly with customers and believe that it is possible for DNOs to build effective direct relationships with, for instance, the energy managers of national companies that operate multiple sites across the DNO regions and with the larger single site businesses.

- The DNOs are newcomers to the DSR market and are effectively in competition with other products such as the National Grid short-term operating reserve (STOR) and the recently introduced demand-side balancing reserve (DSBR) to mitigate the capacity margin squeeze. The key difference is that the DNOs are geographically constrained whereas National Grid has the more choice and the flexibility on which providers to call. An arrangement where the DNO, Transmission System Operator (TSO) and even Transmission Operator (TO) are able to share DSR resource may create value for all stakeholders and is under development. Sharing with suppliers will also be possible once suppliers begin to utilise the value of DSR.

The DSR reliability levels experienced during the trials means that DNOs need to over-procure to achieve the required level of network security

- The CLNR DSR contracts for the 2014 trials delivered an overall reliability of between 43% and 83% reliability, depending on how we include the sites that declared themselves unavailable for the whole of the trial.

- A probabilistic approach is therefore needed when planning, pricing and purchasing DSR by applying a de-rating factor to account for combined availability and utilization reliability.

- Reliability could be improved if the response can be provided a by a portfolio of customers to deliver the overall DNO requirements, each contributing towards the total requirement.

- Aggregators advise us that the lowest DSR capacity to make it worthwhile for their involvement is of the order of 250kW to 500kW per site.

The contract arrangements need to be simple to understand, simple to operate and they must offer a fair price to the provider and the DNO in order to be viable

- Customers that are already participating in STOR are a natural first choice for recruitment, provided that sharing arrangements can be established, as they are already knowledgeable about the concepts of DSR. This makes establishing the contracts a much more straight forward process.

- Otherwise, the lead times from making initial contact with a customer to finalising a DSR contract can range from 12 to 24 months for those customers not already familiar with the concept.

- The CLNR trial established that customers were willing to sign contracts with prices broadly equivalent to STOR for the purpose of the trial with a guaranteed 10 calls. However, this may change given the likely lower frequency of utilisation under our DNO use case scenario.

- There is therefore a balance to be struck which depends upon the risk appetite of both the DNO and the provider. Based upon an analysis of primary fault records it is estimated that the key parameters will be an availability window of the 83 weekdays between November and February and a call duration of 4 hours with the number of calls averaging two per annum (but it could be as low as zero or as high as 14 events).

- The DNO may calculate, on a project by project basis, the maximum £ per MW per year that it is willing to pay, based upon a comparison with the price of the lowest cost reinforcement alternative. The actual price struck will be driven by the law of supply and demand:

    - Customers are looking for a bankable business cases with guaranteed returns from their investment to cover the cost of the required metering, controls, management time, operation / admin time and also changes to business practices and processes if they are offering a load reduction.
    - DNOs need to consider the cost of the actual deferred / avoided reinforcement, the size of the available DSR capacity, the number of potential providers, the aggregated response

reliability and how the benefits are shared between the DSR provider and all DUoS paying customers.

It is easier to procure DSR from standby generation than find a truly flexible load

- DSR from standby generation is currently easier for a DNO to find and sign-up than DSR from load reduction. In theory, DNOs should be agnostic to the method of DSR provision. However, in reality, most DNOs are likely to prefer load turn down as a greener alternative to diesel generation and so may prioritise this form if it can be procured at the same price and reliability.
- Out of the 14 trial customers, we were successful in finding two effective and fast responding flexible loads. The first was provided by refrigeration plant operated by an ice manufacturer (0.6MW) connected at HV and the second was a gas compressor (5MW) connected at EHV. Such load types, particularly refrigeration, offer good potential for demand-side response as the DSR can be accommodated without disruption to working patterns.
- Standby generation appears to be the most successful entry point for I&C customers wishing to participate in DSR schemes as it provides a new revenue stream while minimising the number of changes and new risk to their business operation.
- Following this first step, customers may then consider engaging in developing DSR via load response, which may be more costly to set up and could be more intrusive to their core processes.
- The DNO sector needs to explore more fully the barriers to engaging more load turn-down resource in the RIIO-ED1 period and beyond.

9.1.3 Generator voltage support (Test Cell 19)

Generators that have a capacity between 50MW and 100MW are classed as “Medium Embedded Power Stations” which makes them subject to certain Grid Code compliance requirements, one of which is to have a reactive power capability covering both lagging and leading power factors and to operate in “voltage control mode”. This allows the generator to control the flow of reactive power to maintain voltage within limits as real power output is increased. This facility is historically used by National Grid to manage the voltage on the 275kV and 400kV systems but has been trialled on CLNR with a 54MW wind farm connected at 66kV as an alternative to constraining the generator off. The trial has shown this technique to work successfully and we will review our policies in early 2015 after a full 12 months of operation to include this method for wind farms willing to invest in the STATCOM equipment required to provide this mode of operation.

9.1.4 Generator contribution to network security, based on assessment of generator load profiles (Test Cell 8)

Durham University analysed the output from 62 distributed generation sites in Yorkshire and the Northeast over a period of two years and EA Technology Ltd undertook a further analysis of the profiles and the process for assessing the contribution of distributed generation to network security.

There are two key recommendations with respect to the review of ETR130 for assessing the capability of a distribution network containing distributed generation to meet demand, in order to comply with the security requirements of ER P2/6[25].

- To update the current F factors in ETR130 for the contribution of different DG technologies to distribution network security based on the data collected from the customer field trials of the CLNR project.
- To use the information collected from the customer field trials and associated learning outcomes of the CLNR project to support the "Review of ER P2/6 Working Group" of the Distribution Code Review Panel on the review of ETR 130 methodology for assessing the contribution of DG to network security.

With regard to the F Factors, EATL found the F factors for intermittent generation such as wind farms should be lower than in the original study, which would reduce wind generation's contribution to network security, as follows:

Wind Farms	Persistence T_m (hours)						
	0.5	2	3	18	24	120	360
ETR 130	28%	25%	24%	14%	11%	0%	0%
CLNR trials	19%	15%	14%	8%	6%	0%	0%

Table 10.1: Comparison of the F Factors of wind farms from ETR 130 against the 16 CLNR monitored wind farms

For other, more controllable generation such as landfill gas, CHP, gas, biomass and small hydro, the F Factor calculations from the CLNR trials were broadly similar to those in ETR 130.

With respect to the overall methodology for calculating the contribution to security we recommend that a fully probabilistic risk-based planning approach be developed, using information from CLNR test cell 8, to support the "Review of ER P2/6 Working Group" of the Distribution Code Review Panel on the review of ETR 130 methodology for assessing the contribution of DG to network security.

The consideration within the CLNR project of the modelling structure underlying ETR 130 reveals a number of concerns about how the planning methodology contained therein relates to the real system situations under study. In general, if a simplified approach (such as the F factors used at present) is to be used in assessing the contribution of DG and other new technologies in practical planning, then such a simplified approach should have a sound basis in a particular risk calculation relevant to the real network situations under study. This might either be based in a probabilistic calculation with a particular target risk level, or in a probabilistic cost-benefit analysis between investment cost and future reliability cost. More generally, there is no natural way of extending a deterministic standard such as the present ETR 130 and P2/6 to include distributed resources. The only natural basis for considering such new components of the system is to develop a fully probabilistic risk-based planning approach, which can integrate consideration of all relevant technologies. There are clear advantages of using a simplified approach such as the present F factors

[25] ENA, 2006. "Engineering Recommendation P2/6, Security of Supply", Energy Networks Association, Engineering Directorate, July 2006.

for practical purpose (including resource expended on any individual study, and applicability by a wide range of planning engineers who may not have experience in probability techniques), but in order to have confidence that such an approach will deliver good results it should have a sound basis in a fully detailed calculation. Hence, it is recommended to make use of the information collected from the customer field trials and associated learning outcomes of the CLNR project to support the "Review of ER P2/6 Working Group" of the Distribution Code Review Panel on the review of ETR 130 methodology for assessing the contribution of DG to network security.

9.2 Current Northern Powergrid demand-side activity and future commitments

In this section we identify how the Northern Powergrid business plan has been influenced by the CLNR project learning. By its nature this is highly company specific and it will be up to other DNOs to decide how to incorporate the learning into their own activities.

9.2.1 Current demand-side activity

Our current demand side activities relate to discussions with new customers at the point of connection. There are a number of ways that we work with these customers to reduce the reinforcement requirements of the network which, in turn, reduces the need for increased capacity at transmission and generation levels.

- We help customers achieve a size of connection that meets their needs by looking at what they can do to reduce their impact on the network;
- We give customers options to reduce their cost of connection by discussing their needs and proposing potentially lower cost alternatives
- We let customers know where we have spare capacity (and where we don't) so that if they are locationally flexible they can locate in areas with lower connection charges. See heat maps in http://www.northernpowergrid.com/page/generation_over_16amps.cfm
- We offer customers the benefits of flexibility if customers are willing to have a lower cost connection in return for occasional constraints under certain network conditions i.e. generator export management schemes.

For general load growth, we maximise the benefits from better load information at EHV which allows us to understand the profile of aggregate customer demand to reduce reinforcement costs without involving customers. We also apply voltage optimisation by modifying voltage control schemes at some primary substations to give additional voltage headroom for generator connections.

9.2.2 Future DSR commitments

Our investment plan for the next eight years makes a commitment to continue what we already do in this area, but also to expand our portfolio of techniques based on learning from our own CLNR project, and the innovative research being undertaken by other DNOs.

Connections

Our commercial approach to managing connection requests and applications for load increases will consolidate existing innovative solutions into more mainstream use during 2015-23 and add new techniques, as follows:

- We will assist our customers in reviewing their maximum demand and power factor requirements to identify the most appropriate and cost effective solution.
- We will consistently offer technically innovative solutions to our customers where it is a cheaper, faster alternative to reinforcement for Industrial and Commercial (I&C) connection requests. Currently available examples include flexible connection arrangements, such as a load or generation management scheme, and voltage constrained connections. Real time thermal ratings for intermittent generation connections should be available early in RIIO-ED1.
- Where connectees are not able to eliminate the reinforcement requirements associated with their connection we will design the lowest cost network solution. If the customers planning horizon is sufficient, we will commit to holding an auction calling for DSR from other customers connected to the same network to see if we can find a lower cost alternative to the lowest cost network solution.

General reinforcement

To help manage the long term utilisation of the network, avoiding reinforcement and preventing cost increases for customers in future price control periods we will from 2015 address major substations utilisation by management of the load profile as well as traditional load transfer and reinforcement solutions. We shall operate two methods:

- Firstly we will consider leveraging third party energy efficiency consultants to advise customers connected to the target network on the benefits to them of energy cost reductions and how they can achieve those benefits including energy efficiency measures, time-of-use tariffs and on-demand DSR. This will be targeted at medium to high utilisation areas as a containment measure.
- Secondly we will conduct a reverse capacity auction via our website. We expect this to be more effective in areas where the first method has already been deployed where there is greater awareness of the opportunities. This process will use our experience with I&C DSR trialled as part of our CLNR project and the trials undertaken by other DNOs.

9.3 Recommended tool kits for transition to business as usual

The following set up activities and ongoing responsibilities have been identified to support the transition from trials to business as usual.

FROM DSR TRIALS TO DSR AS BAU

- Identify the people, process and system requirements for DSR operation
- Identify the costs for implementing & operating DSR (hardware capital costs, set up and ongoing operating costs)
- Establish process for undertaking the DSR cost/benefit analysis
- Establish transparent contracts and routes to market (i.e. direct, via aggregators, sharing, capacity auctions, etc)
- Establish DSR hardware / software standards
- Allocate responsibilities and provide training

PLANNING & DESIGN

- Include DSR as an option in all load related reinforcement schemes
- Review all existing load related reinforcement schemes for DSR potential
- Based upon load forecasts and fault history; calculate volume of DSR required (MW), duration of DSR event (minutes), potential frequency of DSR event calls
- Assess the types of customers connected to estimate reliability factors
- Calculate DSR ceiling price and undertake cost/benefit analysis
- Request procurement of DSR for less than the calculated ceiling price

FAULT MANAGEMENT

- Provision of fault data required to identify the DSR requirements
- Review DSR scheme proposals for operational security impact / scheme approval

COMMERCIAL / PROCUREMENT

- Identify potential DSR providers downstream of the constraint point
- Invite tenders and recruit DSR providers at or below the ceiling price
- Negotiate and sign off DSR schemes/contracts for implementation

CONSTRUCTION / TELECOMMS ENGINEERS

- Install, set up & commission monitoring & control systems (i.e. real-time thermal ratings, remote terminal unit, communication links, etc)

CONTROL ENGINEERS

- Review DSR schemes for operational security impact and scheme approval
- Manage the network under fault conditions & respond appropriately to any alarms from the DSR schemes
- Provide feedback on the operational performance of DSR events

BACK OFFICE

- Provide settlement and management of DSR contracts
- Review the performance of DSR contracts

Figure 10.1: Setup activities and ongoing responsibilities

Specific outputs from the CLNR project to assist with this process are as follows:

- CLNR Demand Side Response Application Guide, which covers:
    - Assessing the network requirements
    - Specifying the DSR requirements
    - Calculating the DSR ceiling price
    - Pricing and validation methodologies
    - Recruitment channels
    - Operational implementation

- CLNR DSR training materials, as follows:
    - 1. DSR Overview
    - 2. DSR General
    - 3. DSR Standards and Regulations
    - 4. DSR Safety, Health, Environment
    - 5. DSR Schemes
    - 6. Communications
    - 7. Network Planning
    - 8. DSR Case Studies
    - 9. DSR Assessment

- CLNR DSR ceiling price calculator

10 Glossary

ADMD	After-Diversity Maximum Demand
ADSL	Asymmetric Digital Subscriber Line
ANM	Active Network Management
AVC	Automatic Voltage Control
BAU	Business as Usual
BSC	Balancing and Settlement Code
BSUOS	Balancing services use of system charges
CAF	Cost Apportionment Factor
CCCM	Common Connection Charging Methodology
CDCM	Common Distribution Charging Methodology
CDM	Construction (Design and Management) Regulations
CHP	Combined Heat and Power
CLNR	Customer-Led Network Revolution
COPT	Capacity Outage and Probability Table
DCC	Data Communications Company
DCPR5	Distribution Price Control Review 5
DCUSA	Distribution Connection and Use of System Agreement
DECC	Department of Energy and Climate Change
DG	Distributed Generation
DLE	Distribution Load Estimates
DNO	Distribution Network Operator
DNP	Distributor Network Protocol
DSBR	Demand Side Balancing Reserve
DSM	Demand-Side Management (includes DSR, GSR and EES)
DSO	Distribution System Operator
DSR	Demand Side Response
DSSE	Distribution System State Estimator
DUoS	Distribution Use of System
DVSF	Diversified Voltage Sensitivity Factor
EATL	EA Technology Ltd
EAVC	Enhanced Automatic Voltage Control
EBSCR	Electricity Balancing Significant Code Review
ED1	Electricity Distribution 1, The first RIIO price control period
ED2	Electricity Distribution 2, The second RIIO price control period
EDCM	EHV Distribution Charging Methodology
EE	Energy Efficiency
EENS	Expected Energy Not Supplied
EES	Electrical Energy Storage
EHV	Extra-High Voltage
EMR	Electricity Market Reform
ENA	Energy Networks Association
ESQCR	Electricity Safety, Quality and Continuity Regulations
ETR	Engineering Technical Recommendation
EV	Electric Vehicle

FAT	Factory Acceptance Testing
FCDM	Frequency Control by Demand Management
FDVF	Feeder Diversity Voltage Factor
FDWH	Flexible Data Warehouse
FFR	Firm Frequency Response
FPP	Flexible Plug and Play (UKPN LCN Fund project)
FR	Fast Reserve
GB	Great Britain
GPRS	General Packet Radio Services
GSR	Generation Side Response
GUS	Grand Unified Scheme (Control Infrastructure)
HH	Half-hourly
HP	Heat Pumps
HV	High Voltage
HVAC	Heating, Ventilation and Air Conditioning
I&C	Industrial & Commercial
I/O	Input/Output
IHD	In-Home Display
IIS	Interruption Incentive Scheme
IQI	Information Quality Incentive
ITT	Invitation To Tender
LCN	Low Carbon Networks
LCT	Low Carbon Technology
LDC	Load Duration Curve
LoU	Location of Use
LV	Low Voltage (ie below 1000V line-to-line)
LVN	LV Network
mCHP	Micro Combined Heat and Power
MEPS	Medium Embedded Power Station
MIP	Market Index Price
MPAN	Meter Point Administration Number
MRA	Master Registration Agreement
NETSO	Network Electricity Transmission System Operator
NMS	Network Management System
NO	Network Operator
NPADDS	Network Planning and Design Decision Support Tool
NPS	Network Product Specifications
NPV	Net Present Value
OLTC	On-Load Tap Changer
PC	Profile Class
PQ mode	Generator operated in power factor control mode
PV	Photovoltaic
PV mode	Generator operated in voltage control mode
RDC	Remote Distribution Controller
RIIO	Revenue = Incentives + Innovation + Outputs
RTTR	Real-Time Thermal Ratings

RTU	Remote Terminal Unit
SAT	Site Acceptance Testing
SBP	System Buy Price
SBR	Supplemental Balancing Reserve
SEC	Smarter Energy Code
SGF	Smart Grid Forum Workstream 6
SGF WS6	Smart Grid Forum
SME	Small and Medium-sized Enterprises
SMS	Short Message Service
SO	System Operator
SSC	Standards Settlement Configuration
SSP	System Sell Price
STOR	Short Term Operating Reserve
TNUoS	Transmission Network Use of System
TO	Transmission Network Operator
ToU	Time of Use
TSO	Transmission System Operator
UKPN	UK Power Networks
VCC	Volt-Var Control
VEEEG	validation, extension, extrapolation, enhancement and generalisation
VPN	Virtual Private Network
VSF	Voltage sensitivity factor