Customer-Led Network Revolution

DEVELOPING THE SMARTER GRID:

Optimal solutions for smarter network businesses

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Leading the way to a low carbon world

The Customer-Led Network Revolution

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.

It was designed to test a range of customer-side solutions (innovative tariffs and load control incentives) alone and in combination with network-side technology, including voltage control, real-time thermal rating and energy storage. The project was designed to deliver robust learning that would be applicable to a high percentage of GB networks and demographic groups.

Around 13,000 domestic, small and medium sized enterprise (SME), industrial and commercial (I&C) customers and merchant generators took part in the project, which involved the trialling of innovative smart grid solutions on Northern Powergrid's electricity network and the trialling of novel commercial arrangements to encourage customer flexibility.

Learning from the project will help distribution network operator (DNOs) find cost-effective ways to manage the introduction of low carbon technologies (LCTs) such as 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, research novel network and commercial tools and techniques and to establish how they can be integrated to accommodate the growth of 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.

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- Northern Powergrid
- EA Technology
- Durham University
- Newcastle University

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1. EXECUTIVE SUMMARY

1.1. Overview

The Customer-Led Network Revolution (CLNR) project demonstrated a large-scale smart grid deployment. It combined technical and social science aspects by considering both the role of customers as individuals in the power system, and also the network-side technologies we will use in the near future. These halves came together in finding out what additional demands customers place on the system from the way they used energy; and in finding out how they could reduce demands on the system by changing their behaviour in response to tariffs and direct control signals.

Specifically, on the technical side we deployed and evaluated: enhanced ratings for existing assets; enhanced techniques for existing active voltage control devices; new active voltage control devices in locations that did not have them before; electrical energy storage (EES) systems transferring both real and reactive power (therefore also acting as static compensators); and a hierarchal deployment of an active network management system providing both local control and an area control coordinating and optimising settings.

This report looks at the results from the customer-facing and network-facing trials, to propose an optimal blend of network and non-network solutions to allow distribution network operators (DNOs) to meet the evolving demands of their customers more efficiently. This learning, which is applicable to all DNO networks, has shown that there is no 'one-size-fits-all' solution and that the solutions deployed can start relatively simple and become more complex over time.

DNOs will be able to reduce the amount of conventional reinforcement that would otherwise be required by turning to smarter lower-cost solutions instead, but these solutions need only be as smart as is necessary to address each problem.

We have proved that local solutions fit local problems, and that simple solutions fit simple problems. If DNOs deploy the techniques outlined in this report, they can travel the smart/smarter/smartest path – from simple, local solutions to complex wide-area solutions – without the risk of stranded assets, using evolutionary steps.

- From better default thermal ratings, to bespoke thermal ratings, to full real-time thermal ratings (RTTR) and demand side management (DSM) for a single asset, to an area controller optimising the use of DSM to resolve multiple potential power flow constraints
- From better default voltage settings, to bespoke voltage settings, to additional active control devices using bespoke settings and local control, to an area controller optimising the set-points of multiple active control devices; or
- From separate control for voltage and power flow issues to integrated area control

There are no fixed timescales for this journey: our customers will drive the pace. It is likely that there will be a handful of areas in Great Britain where a fully integrated area control will be deployed in the RIIO-ED1 regulatory period, i.e. before 2023; it is likely that there will be areas in Great Britain where conventional solutions will remain the most effective option through to 2050.

Having deployed all these solutions in the CLNR project, we have learned how to make them work for particular constraints or combinations of constraints and also the decision points that inform the move from one evolutionary step to the next.

We can also see that customers' choices will be diverse, so constraints will evolve on different parts of the network at varied rates, therefore requiring a variety of solutions to be applied depending on the location. We have projected until 2050 to future-proof our proposals so far as we can and, due to the level of uncertainty in growth projections, have developed an approach that allows DNOs to leave their options open rather than tying themselves into rigid programmes.

1.2. Customer demand

First, DNOs need to understand how the design of their distribution networks needs to evolve to respond to the growth in LCTs and changes in customer behaviours. The CLNR customer monitoring and flexibility trial results come from a detailed and statistically significant bottom-up analysis of individual customers' behaviour, backed up by academic analysis of interviews with a cross-section of customers and the monitoring of network clusters.

We have learned that:

- Regular domestic customers[1] contribute about 40% less to system peak demand than previously assumed, down from 1.5kW to 0.9kW. This is a combination of customers using less energy overall through the year, and also drawing power more evenly across the day and year. This is likely to be driven by a combination of changes in behaviour and more efficient equipment
- The network impact of individual heat pumps and electric vehicles is more benign than previously assumed, so we are proposing that DNOs work on the basis that customers with a heat pump, or customers with an electric vehicle, contribute twice the peak demand of regular domestic customers

We have confirmed the hypothesis that the output of solar photovoltaic installations does diversify with increasing numbers of installations, because the panels point in different directions and therefore produce their peak output at different times of day, but the impact of this diversity is small.

We therefore propose:

- A default planning assumption of 90% of aggregate declared capacity, higher than the Western Power Distribution's network templates assumption of 80%
- That the planning assumption should rise to 100% where the panels are closely aligned

We have also found that average domestic demand on a sunny summer afternoon from a housing estate with PV offsets that PV export by about 0.3kW.

We have translated these findings into values for the industry standard method for modelling local networks, providing DEBUT[2] coefficients for the modelling method specified in Electricity Networks Association (ENA) ACE report 49 'Statistical method for calculating demands and voltage regulations on LV radial distribution systems' and ENA ACE report 105 'Report on the design of low voltage underground networks for new housing'. We have also begun to explore a new way of modelling the maximum demand of a group of customers. This is discussed in more detail in section 5 of this report.

We have found little evidence of LCT customer equipment (i.e. heat pumps, electric vehicles or solar PV) creating power quality problems for the clusters studied in CLNR. This is consistent with similar studies by other DNOs. Even with smarter solutions, DNOs will still need to lay some new LV cable to cater for the increased power flow from clusters of LCTs, with the positive side effect of reducing impedance: this reduces any remaining risk of power quality issues. This is discussed in more detail in section 9 of this report.

1.3. Modelling and monitoring

Now we know the potential impact of the growth of LCTs, the next step is to forecast where we are running short on capacity, which requires modelling and monitoring.

Through the development of tools for planning and design, and also the development of systems for real-time control, CLNR has shown that we need the same knowledge for each application, it is just the latency and resolution of data that changes.

We know we need to understand power flow and voltage across all network voltage levels down to the point of delivery to the connected customer, otherwise we risk overloading assets or delivering voltage outside the statutory limits. We know we need to understand customer behaviour and network response across intervals of five or 10-minutes to match asset thermal time constants and the European voltage standards. CLNR suggests that there is not a major issue from harmonics, but it is something we need to keep an eye on.

This level of understanding will be delivered from a mix of heuristics, modelling and monitoring. The more diverse customers' behaviour is, the more monitoring we need – first to validate offline models and then to inform real-time control systems. All these systems, like the CLNR solution, rely to some degree on heuristics to define the detail in which we model the system: complex systems, like the CLNR state estimator, include online models.

There is a journey from data, through information, to knowledge before any solution can be deployed. What we need to know defines the analysis we need to carry out to identify the processing and storage we need, which in turn defines the data we need to collect and the actions we then take.

Therefore, as the need arises (i.e. as customers become more diverse in their load characteristics and behaviours and the network becomes more heavily loaded in some places), we will move from simple demand indicators on secondary substations and half-hour average directionless current on HV feeder heads, to five or 10-minute average measurements of four quadrant power and total harmonic distortion on all feeder heads, and of voltage on each busbar, at every substation.

Where possible, we will use customer metering instead of installing our own monitoring. For example, the smart meter roll-out brings obvious benefits for offline modelling, and we may also be able to use voltage alerts in event-driven real-time area controllers.

We will bring key analogues, e.g. set-points issued by the active network management (ANM) system, back to core SCADA. This not only provides the control engineer with visibility of what the control scheme is doing, it allows us to use existing data archive facilities to record what the control scheme has done, for later off-line analysis. As outlined above, this analysis drives the data we store, so we need to be sure we bring back just enough data to help work out why the control scheme made its decisions: to avoid creating excess infrastructure, this will generally be limited to defining what the key analogues are. This challenge becomes significantly more complex when using state estimation and optimisation, because the number of data points which influences those decisions increases by orders of magnitude, so we may then need to use a separate engineering console to track the detailed operation of the system.

Where we collect data for purely off-line analysis, we will need some form of data warehouse. This is discussed in more detail in section 11 of this report.

[1] i.e. Customers without heat pumps, electric vehicles or photo-voltaic cells
[2] DEBUT is an LV network design tool describing ACE49 and ACE105

1.4. Non-network solutions

Where we have identified a shortfall in capacity, the first stage should be to see whether we can provide capacity without building more network. This involves exploring the potential for demand side management (DSM), which comprises demand side response (DSR), generator side response (GSR) and electrical energy storage (EES), provided on a voluntary commercial basis[3].

We have found that time of use (ToU) tariffs are very popular with domestic customers, where more save money than lose out, although the impact in this trial on absolute peak demand was marginal. However, coordination of ToU tariffs with suppliers has the potential to deliver greater value to customers and a more significant impact on peak demand.

We have found that I&C DSR can 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. We have shown an overall reliability of up to 83%. DSR offers significant advantages to the conventional business as usual solutions currently deployed to overcome network constraints. It can be contracted annually, allowing it to be turned off if not required in future years; as it causes no impact on the environment; and it provides a financial benefit to customers i.e. those that provide the DSR service and others that benefit by not having to fund more expensive options through future distribution use of system (DUoS) payments. However, when recruiting potential providers, the initial customer drop-out rates can be high due to issues with contacting the sites. Communicating with the right person at the site, the degree of flexibility available and the nature of the service required are all key. This problem is exacerbated when targeting a tight geographic area where the number of potential suitable providers may be low.

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 major substations that are forecast to be occasionally loaded above capacity during the winter evening peaks. The benefit available depends on the size and duration of that peak, typically yielding a 10-15% increase in power flow capacity. DSR could be activated following a fault on the network that either occurs during, or cannot be restored before the onset of, the forecast peak. We have proved the systems that make this work.

We have developed a suite of solutions for deploying EES onto distribution systems, both as storage owner and distribution system operator. We have published documents defining requirements for procurement, installation, operation and maintenance. Treating storage as a generator for specifying interface protection, using the industry standard settings specified in ENA Engineering Recommendation G59, has been proven to work. We have used controllers within the substation to drive storage to resolve local voltage and thermal issues. We have used an area controller (qv) to optimise the set-points of storage charging and discharging to resolve voltage and thermal issues across a network.

There are some practical limitations to using storage. The units are large, heavy and can be noisy, so they can not be used everywhere. Present state-of-charge algorithms are unreliable, and battery ageing and lifespan is not well understood, so capacity is uncertain.

We have shown that storage, and all DSM, gives greatest benefit at lower voltage tiers of the network. The main benefit comes from resolving multiple series constraints e.g. at both the local secondary transformer and also the area primary transformer. This would allow us to increase the price we'd pay for DSM, as we'd be able to factor in the value of deferring both potential transformer upgrades.

We have determined that third party providers can unlock the benefits of storage more readily because they face fewer regulatory restrictions so it is easier for them to access other value streams. We have also shown that storage and DSR provide similar system benefits, can be combined efficiently to commercial advantage, and can be driven by a single well-designed control system. Therefore, we propose that all sources of DSM are treated the same way, looking only for a contracted-out real power response service.

These solutions are covered in more detail in sections 7.2 and 8.4 of this report and in these companion reports:

- CLNR-L145: Commercial Arrangements – Phase 2 (2014)
- CLNR-L246: Developing the smarter grid: the role of domestic and small and medium enterprise customers
- CLNR-L247: Developing the smarter grid: the role of industrial and commercial and distributed generation customers

We have reviewed the contribution of real generators to system security, using the industry standard method specified in ENA Engineering Technical Reports 130 and 131. Specifically, we have found that wind farms contribute less to system security than we thought, so we propose to reduce their credit for the key three-hour window from 24% of declared net capacity to 14%. This is discussed in more detail in section 6 of this report.

1.5. Enhanced thermal ratings

Other projects often label off-line backward-looking bespoke fixed rating as RTTR. This is not the case in the CLNR project, so it is important to be clear about the stages of enhancing asset ratings:

- Pick the right model for the assets
- Pick the right default inputs for the model to get accurate default static ratings. For example, we suggest using a value for soil thermal resistivity of 1.5K/W-m rather than 0.9 which is the present GB standard. This reduces default cable ratings by about 10%
- To understand whether we can defer reinforcement of a high value asset, measure the key inputs and run the model to get a bespoke static rating, for example:
  - Measuring thermal response of transformers
  - Measuring wind speed at, or in reasonable proximity to, sheltered overhead line spans; and
  - Taking samples to determine the soil drying-out curve and hence predict soil thermal resistivity
- Finally, there will be a few occasions where we can make decisions in real-time based on working out the rating in real-time, this is true RTTR. Our work has revealed little value in doing this for cables because of the slow rate of change of the relevant parameters, but we have found up to 40% more non-firm capacity on lines and transformers

  Opportunities include:
  - Maximising the output from a wind farm connected by overhead line, where the key parameter we need to measure is wind speed
  - Minimising the use of DSM to offload a major transformer where, once we understand the thermal response, the key parameter we need to measure is the current

Taking this to a practical level, we have found no reason to change the principles of present asset ratings, as expressed in ENA Engineering Recommendations P15/17/27[4], but we have demonstrated the need to use the right correction factors, which already exist in those standards.

We have also integrated true real-time and dynamic thermal ratings into a sophisticated area control scheme. We have used it to optimally control the use of DSM, and the same approach could easily be applied to maximise system availability for controllable distributed generation. We have also found that we can get a significant increase in system capability by teaming RTTR and a relatively small EES device. This is discussed in more detail in section 7.1 of this report.

1.6. Enhanced voltage control

We have found that there is a lot to be gained from enhancing load-drop compensation to manage voltage rise from distributed generation. We recognise that this is harder to implement when there is a lot of generation masking the load, which may be the driver to move to an area control scheme.

With load-drop compensation, we have shown that a standard default setting of a 3% reduction in target voltage at minimum demand lets us accommodate most of the small-scale solar photovoltaic generation that we expect to be connected by 2050. We recognise that there may be clusters of customers who ask more of the system, so default voltage settings will not apply there. We have shown that bespoke analysis of voltage settings can release additional capacity for such clusters, with 6% permissible reduction in target voltage for the scenarios we have modelled.

Similarly, a bespoke assessment may permit voltage regulating relay dead-bands to be reduced without unduly increasing tap-changer operations, releasing voltage headroom of around 1%.

As customers' behaviour becomes increasingly varied, it is more likely that we will get high volts on one part of a system and low volts on another. A single active control device cannot fix this, no matter how clever the algorithm behind it, therefore additional active control devices, which will release headroom widely across the system, will need to be added. For example, if we fit a voltage regulator to bring down the volts on a generation-rich feeder, the voltage can then be set higher at the primary substation to accommodate more load on the other feeders.

We have found that, in general, the optimal choice of device is an in-line HV regulator in rural areas and on-load tap-changer (OLTC) on a secondary transformer in urban areas. This is because we expect challenges and benefits across a number of substations in rural areas, but only in pockets in urban areas.

When the need arises, so long as we specify those additional active control devices properly, we can later integrate them into an area control scheme (qv) to coordinate their set points and optimise voltages across the system.

We have quantified the benefits of:

- Dispatching real and reactive power for voltage control, where the extra voltage headroom released for practical applications is 1% to 2%; and
- Providing new on-load tap-changers, where the percentage voltage headroom released is roughly equal to the percentage tapping range

This is discussed in more detail in section 8.1 of this report.

[3] CLNR has not considered mandatory restrictions on customers through their connection agreements
[4] Ratings for transformers, cables and overhead lines respectively

1.7. Synergies and combinations

CLNR puts customers at the heart of the distribution system, from understanding what they need the network to deliver to engaging better with them on how they can help reduce the future levels of reinforcement needed. The key element of the network side of the CLNR learning is how to combine multiple solutions – both non-network and network – to achieve an overall optimal solution.

The flagship for combining solutions is the area control scheme, and there are also local autonomous solutions which work well together, such as:

- Voltage control using both real and reactive power from EES
- Combining EES and DSR:
  - Minimising the energy required of both, thereby reducing operating costs; and
  - Using the fast-acting EES response to offset the slower DSR action
- Using DSM to address both power flow and voltage issues

In CLNR, we have deployed a highly-sophisticated area control scheme, combining state estimation — where we have modelled the system from 66,000V down to 400V – and an online optimisation engine. We have fed this from widespread monitoring, down to the ends of LV feeders, and used real-time thermal ratings for lines, cables and transformers. This has enabled us to:

- Resolve both voltage and power flow issues at the same time, rather than either one in isolation; and
- Use both real and reactive power sources at the same time

We have integrated this with our existing core SCADA, feeding key information from the new scheme into that SCADA, and we have a baseline specification to do more. We also feed the open/close status of network switchgear from SCADA into the new control scheme to avoid duplicating on-site measurement. This is particularly valuable on the HV network where there are hundreds of switches to take into account.

We have shown that this area control adds value in:

- Optimising the use of DSM. We can use the same DSM resource to address multiple series constraints, whether voltage or power flow or both, and we can aggregate discrete DSM resources into something much more powerful; and
- Optimising voltage set-points across a number of active voltage control devices. To get the best out of the active voltage control devices we will deploy an online optimisation tool to select the best set-points enabling these devices to work in harmony. This is particularly important when using reactive power for voltage control, because it affects a wide part of the system

Online state estimation and optimisation is, however, a complex solution, and can be justified only where there are complex network problems. We have shown that simpler techniques can address simpler problems nearly as effectively and likely more efficiently, but we wouldn't have learned the decision points for increasing the levels of complexity had we not implemented and understood the more powerful solution. This is discussed in more detail in section 10 of this report.

1.8. New tools

We have written a generic smart grid safety case, backed up by detailed documents for the installation, operation and maintenance of each new technology deployed.

To better understand the fundamentals of how customers and networks behave we have also developed new tools for systematic analysis of each, including:

- Development of a socio-technical framework for understanding the provision and use of energy services
- A validation, extension, extrapolation, enhancement and generalisation (VEEEG) framework to specify, prioritise and analyse field trials of new methods
- New metrics to define network response, including diversified voltage sensitivity factors and feeder voltage diversity factors

These are aimed at academic and high-end policy work.

For day-to-day application, the prototype Network Planning and Design Decision Support (NPADDS) tool enables analysis of solar photovoltaic (PV), electric vehicles (EVs) and heat pumps (HPs) on a network. It also illustrates a process of ranking, design and analysis of example headroom solutions that were trialled by the CLNR project, within the context of the Smart Grid Forum Workstream 3 (SGF WS3) solutions.

NPADDS is a case-specific tool, not one that uses generic rules to make sweeping statements. It brings in network data from host systems using the Common Information Model, and applies customer demands using the coefficients developed for the key customer groups in CLNR, to carry out a bespoke bottom-up power flow analysis across LV and HV networks. We have developed detailed specifications for all the CLNR solutions.

1.9. Merit order

Tangible benefits come from practical guidance for business as usual (BAU) deployment, so we have developed a merit order for solutions for a smarter network. Solving power flow issues also often solves voltage issues, which gives the following logical order to follow:

Confirm the issue

- Model the system to identify potential capability gaps
- Where necessary, monitor to validate the model

For thermal issues:

- Where cost-effective, carry out a bespoke thermal rating study, e.g:
  - transformer thermal tests
  - soil thermal resistivity tests
  - wind speed measuring/modelling
- Invite tenders for DSM (DSR, GSR and EES), priced against deferring the lowest cost conventional alternative
- Where multiple DSM resources, capable of addressing multiple series power flow constraints exist, deploy an area coordinating control scheme
- Where required, reinforce to close the remaining capability gap

For any remaining voltage issues

- Apply default 3% load-drop/generation-rise compensation setting on all active voltage control devices
- Carry out bespoke voltage setting analysis for:
  - Increased load-drop/voltage-rise compensation settings
  - Tighter dead-bands
- Direct controllable DG to operate with bespoke reactive power settings (e.g. PV mode) where contracts permit
- Direct controllable DG to operate with bespoke real power settings (e.g. trimming real output to avoid breaching a defined upper voltage limit at the terminals) where contracts permit
- Invite tenders for DSM, for both real and reactive power, to address voltage issues, priced against deferring the conventional alternative
- Deploy as many additional control devices as required, with bespoke analysis of settings:
  - In urban areas – OLTC at the local substation serving the affected cluster
  - In rural areas – HV regulators
- Deploy area control to coordinate the set-points of voltage control devices (including constrained DG)
- Reinforce the network, where required, to close the remaining capability gap

We have shown that all DSM provides similar benefits, so we are not going to choose winners here. For example, we are not going to rule EES in or out: if it is the most economical solution, we will use it. This is discussed in more detail in sections 14.2 and 14.3 of this report.

1.10. Proposed implementation

Method	How Northern Powergrid plans to modify its distribution system based on CLNR learning	Implementation requirements[5]		Likelihood of wide-scale deployment	Recommendations on how the CLNR outcomes could be exploited further[6]
		DNO actions	Non-DNO actions		
New Customer Demands for Network Planning	We have used the rich CLNR information set on existing customers' behaviour to propose updates to the existing industry modelling standards ENA-ACE 49 and 105, i.e. We have: a) Published network design coefficients (p and q values in ACE 49/105 terminology, related to mean and standard deviation values of consumption for each half-hour of the nominal peak day) for general domestic customers with high, medium and low annual consumption; b) Published new sets of design coefficients, in an industry standard format, suitable for existing industry standard tools, to represent emerging customer behaviour, specifically: i) Electric vehicles; ii) Heat pumps; iii) Solar PV	We have revised the design demands used in our LV designs We have included PV diversity in our generator connection policy. Wider adoption is subject to normal industry governance via the Electricity Networks Futures Group (ENFG).		We see no reason why these coefficients should not be adopted across all DNOs for all LV design assessments, except for the simplest.	There are some customer groups where we struggled with recruitment. Applying CLNR methods, particularly the contribution of the academic partners, to more customers of those types could increase our confidence in the results.
Time of Use Tariffs (ToU)	We already have ToU tariffs for existing half-hourly metered customers and our profile class 1-8 customers, with an April 2015 implementation date. Changes to billing arrangements have a November 15 implementation date. This preparation lays the foundation for DNOs to influence the price incentives given to customers with the roll-out of smart meters.	The migration to half-hourly settlement will be supplier driven, but it is important that suppliers and DNOs work together to ensure customers are not disadvantaged and are fully aware of the changes that are being implemented.	Electricity suppliers need to build on the ToU pricing signals already there for large customers and being made available for all customers, to offer ToU tariffs to their customers. These changes are being managed by the Distribution Charging Methodology Forum (DCMF), Methodology Issues Group (MIG) which is attended by DNOs, suppliers, other industry specialists and Ofgem.	Our ToU tariffs will be available for all our customers but take-up will be dictated by the roll-out of smart meters, how our price signals are built into the tariff offerings from electricity suppliers, the extent to which suppliers promote these tariffs and the response by customers.	The tariffs are ready for deployment, awaiting the smart meter roll-out and required changes to billing arrangements.

Method	How Northern Powergrid plans to modify its distribution system based on CLNR learning	Implementation requirements[5]		Likelihood of wide-scale deployment	Recommendations on how the CLNR outcomes could be exploited further[6]
		DNO actions	Non-DNO actions		
Demand Side Management (DSR, GSR and EES)	For those few major substations that we expect to approach capacity through 2023 (the RIIO-ED1 regulatory period), we will go to the market for DSM as an alternative to network solutions. We expect third parties to be better placed than us to exploit additional income streams from EES, so we will explicitly rule EES in as an option for the contracted DSM service alongside DSR and GSR (but are always likely to rule it out as a capital investment for our business due to the high cost of the technology).	Develop a capability to identify DSR potential and to market and manage DSR contracts either directly or via an aggregator or supplier.	a) Potential providers of 'negawatts' from energy storage, or other sources, need to exploit the revenue streams we have identified in the Commercial Arrangements report, so that they may release the full value of their product. We expect this to bring more such providers forwards; b) EES manufacturers need to develop their products to improve their viability. This is not just about cost, but also about practical installation issues such as size, weight and noise.	We will always look for 'negawatts' as a solution to power flow constraints at major sites. Take up will be constrained only by our customers, either in whether they continue to consume more electricity and therefore advance power flow constraints, or whether they are able and willing to offer 'negawatts' at a competitive rate relative to the lowest cost network solution.	This solution is ready for deployment. The DSM learning from CLNR and other LCN fund projects will be consolidated to maximize learning in this area. Northern Powergrid policy and procedures are being amended to ensure DSM is always included as a potential solution in our network planning and solutions design.
Enhanced Ratings	We have reviewed our ratings policy and, where initial assessment (e.g. the annual survey of the primary network above 20kV) indicates reducing thermal margins, we will roll-out bespoke rating assessments for all assets and all customer groups.	This solution is ready for deployment taking information from CLNR and from other LCNF projects. We would encourage the ENFG to write to the Health and Safety Executive (HSE).	As part of its review of the guidelines for the Electricity Safety, Quality and Continuity Regulations (ESQCR), the HSE should provide clarity on how to assess the 'sufficiency' of an asset and the 'maximum likely temperature' of an overhead line. CLNR has highlighted how both these concepts are probabilistic rather than deterministic and we will feed our views into that review.	Potentially, this could apply to all assets operating above 20kV: roll-out will be driven by demand growth, which will be driven by customer behaviour.	

[5] If the Method is not ready to be implemented, the DNO should explain what needs to happen, including any necessary further work, before the Method(s) can be implemented

[6] i.e. recommendations of what form of trialling will be required to move the Method to the next TRL

Method	How Northern Powergrid plans to modify its distribution system based on CLNR learning	Implementation requirements[5]		Likelihood of wide-scale deployment	Recommendations on how the CLNR outcomes could be exploited further[6]
		DNO actions	Non-DNO actions		
RTTR	For DG connection customers on a potential thermal constraint, we will offer RTTR on overhead lines and on transformers, to optimise the commercial viability of those developers' schemes. RTTR will also be used on circuits that have DSM support to be used as a means of triggering the DSM response.	This solution is ready for deployment taking information from CLNR and from other LCNF projects.	As part of its review of the guidelines for the ESQCR, the HSE should provide clarity on how to assess the 'sufficiency' of an asset and the 'maximum likely temperature' of an overhead line. CLNR has highlighted how both these concepts are probabilistic rather than deterministic and we will feed our views into that review.	We will make full-blown RTTR available across the higher voltage network, but we expect take-up to be in single figures through 2015 to 2023.	Applying CLNR research methods, particularly the contribution of the academic partners, to more overhead line trials could increase our confidence in the results.
Enhanced Voltage Control	We are writing a revised Northern Powergrid voltage control policy to apply the CLNR learning and are specifying a new AVC relay to enable enhanced load-drop compensation at every primary. We will roll-out the use of enhanced load-drop (generation-rise) compensation to the target voltage setting of automatic voltage control relays to most substations above 20kV through 2015 to 2023.	This solution is ready for deployment taking information from CLNR and from other LCNF projects.		This applies to the vast majority of our substations above 20kV, excluding only those that serve compact industrial networks.	Shift from simple voltage control to complex voltage control using multiple devices. i.e. EAVC at the primary substation and on-load tap-changers or HV regulators on the HV feeders (see below).
Additional Voltage Control	a) We will roll-out secondary distribution transformers with OLTC as a business-as-usual solution for PV clusters likely to have voltage issues b) We will roll out the use of HV voltage regulators as a business as usual solution for HV feeders to customer groups whose load characteristics differ significantly from those around them.	This solution is ready for deployment taking information from CLNR and from other LCNF projects.		Take-up of the secondary OLTC and HV regulators depends upon how competitive they are with respect to other solutions: we expect to deploy a handful of each every year.	
Smart RTUs	We are producing a specification for a new RTU roll-out during RIIO-ED1 and we will deploy the smarter characteristics of these RTUs to manage the use of DSM to off-load primary substations under n-1 fault conditions during constrained periods (see previous note on DSM).	We shall make our specification available to DNOs to facilitate deployment.		This is an enabler to DSM (see previous).	

Method	How Northern Powergrid plans to modify its distribution system based on CLNR learning	Implementation requirements[5]		Likelihood of wide-scale deployment	Recommendations on how the CLNR outcomes could be exploited further[6]
		DNO actions	Non-DNO actions		
Area Control	We will build on what we have learnt in CLNR, on what we learnt from our Blyth GEMS scheme (which manages over 500MW of generation to relieve a power flow constraint at the DNO/NGET boundary), and on what we have learnt from other DNOs' ANM projects, to continue to roll-out coordinated control as a business as usual solution for faster and cheaper solution to connected DG to congested parts of the distribution system.	The version of the local and central controllers used for CLNR is, in itself, at technology readiness level 9, because we've proven it on the operational system. Building on that success, we would upgrade the specification for the BAU version of both local (Smart RTU) and the area controllers (ANM specification), so there is some further work to achieve this level of functionality during RIIO-ED1.		We expect to see three or four coordinated control schemes commissioned each year in Great Britain. These may not be exactly the same as the vendor-specific CLNR solution, but many of the same principles will apply. We expect only one or two opportunities to arise before 2023 in Great Britain which demand the complexity of the vendor-specific CLNR solution.	There would be value in a comprehensive compare-and-contrast exercise between the DNOs, where we discuss what we have learnt about the various coordinated control schemes we have deployed. We will share what we have learnt both through informal exchange and in the more structured environment of the ENA ANM working group. The outcomes of the latter will be captured in a good practice guide. There will be no 'one-size-fits-all' solution, but we would then be better prepared to specify and implement appropriate solutions, and also to stimulate a competitive market for providing these solutions.
NPADDS	We will work with other DNOs to combine the learning generated from the range of design tools developed, mostly as prototypes, over recent years.	The vendor-specific solution deployed in CLNR is at around technology readiness level 6, so it requires more development to become available as a commercial product.		Modelling capability like that developed in NPADDS will be required by every DNO.	There have been a number of design tools developed in recent DNO R&D projects, and we need to share what we have each learnt to develop something which combines the best aspects of each approach.
TRANSFORM®	a) We have prepared revised TRANSFORM® solutions templates to reflect the updated learning on the costs and benefits of the CLNR smart solutions.	The solution templates are ready for deployment, subject to the ENA Transform governance process. DNOs can use these to update their long-term planning assumptions.			

[5] If the Method is not ready to be implemented, the DNO should explain what needs to happen, including any necessary further work, before the Method(s) can be implemented

[6] i.e. recommendations of what form of trialling will be required to move the Method to the next TRL

2. INTRODUCTION

2.1. Purpose

The key purpose of this paper is to propose a framework for deploying CLNR solutions in an effective and efficient manner. This requires a comparison to conventional solutions, as well as between novel solutions as trialled in CLNR.

2.2. Scope

The core of this paper, and similar CLNR close-down papers, is to disseminate the outputs from the CLNR programme. While CLNR generally will have regard to other innovation projects, detailed comparison to non-CLNR solutions is out of scope.

This paper is labelled as 'optimal solutions for smarter distribution businesses' because:

- It discusses non-network solutions as well as network solutions both conventional and novel; and
- It focuses upon the benefits to a distribution network operator rather than any other industry actor

There is a subsidiary CLNR paper covering commercial arrangements which, as the name suggests, will survey in detail the commercial issues surrounding ToU tariffs, demand-side response (DSR) and the use of EES. This paper will take some of those conclusions, to establish a merit order of solutions.

During the course of the equipment trials a large amount of learning has been developed. This learning has been documented in a wide range of reports[7], including:

- National standards updates
- Policy updates
- Cost benefit analysis
  - » Cost analysis
  - » VEEEG benefit reports
- Technical specification recommendations for purchase
- Installation, operation and maintenance guides
- Full training material portfolio
- Enhanced network monitoring report
- Power quality impact report
- NPADDS specification and function documents

A full list is provided in the appendix on technical reports.

2.3. Structure

This paper will present the safety case for future distribution systems.

This is not a barrier, nor should it be considered in any negative way. Getting more for less out of existing assets means we are knowingly accepting a risk of overloading those assets, so we need an appropriate set of checks and balances in place to avoid that.

CLNR findings move us from thinking about networks to thinking about systems, so this report includes:

- An overview of the CLNR methods describing what we have done on the programme. More detail on each solution is then provided in relevant sections later in the document
- A discussion of the demands which customers may place on the distribution system, so we have a better idea of what we should be planning to provide. This includes our first non-network solution, of static ToU tariffs for domestic customers
- A discussion of each opportunity (i.e. thermal and then voltage constraint) and each solution, described in more detail, so that we can address their likely contribution to the future distribution system
- A review of the effect on power quality of the new technologies embraced by customers in the CLNR trials, specifically to discuss whether we should change the default value for network impedance, which will affect network design and, crudely, the size of cable we need to lay
- The case for enhanced monitoring of the impact of customer behaviour on the network and how it affects the distribution system
- How the various solutions combine, specifically addressing the successful deployment of the highly sophisticated coordinated area control scheme deployed in CLNR
- Observations on future-proofing any policy decisions we might take
- A merit order – assessing each solution in context – to provide practical guidance on how to develop a smarter distribution system

Appendices giving more detail on some of these issues are at the end.

2.4. 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[8] that will impact the electricity system:

- **Carbon reduction targets:** The achievement of 2020 and 2050 carbon reduction targets[9] 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 Great British 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 the customer will decide when they operate. Customers will be encouraged to participate in DSR 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.

2.5. 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 in Figure 1.

Figure 1: Navigating the CLNR project outputs

[7] CLNR learning has been documented and is located: http://www.networkrevolution.co.uk/resources/project-library/
[8] ENSG 'A smart grid routemap' 2010
[9] Climate Change Act 2008 stipulates that the UK must reduce its CO2 emissions to 34% lower than the 1990 levels by 2020 and 80% lower by 2050

3. METHOD: AN OVERVIEW

CLNR is a smart grid in a box:

We have undertaken a comprehensive study of what the future power system might look like by:

- Taking data from thousands of customers with smart meters to understand how they use electricity today
- Extending this study to hundreds of customers at the leading edge of emerging trends, such as:
  - Electric vehicles
  - Heat pumps
  - Solar PV
- Looking ahead to better engaging customers, by including hundreds of them in trials to change their patterns of consumption
- Interviewing dozens of customers to gain qualitative insight into energy practices
- Trialling energy storage as another non-network solution
- Trialling better use of existing network solutions, like primary transformers with on-load tap-changers, or in-line voltage regulators, or switched capacitor banks, which all manage voltage
- Trialling novel network solutions, such as:
  - RTTR of primary and secondary transformers, overhead lines, and underground cables
  - secondary transformers with on-load tap-changers
- Deploying a highly sophisticated real-time control scheme which simultaneously manages multiple non-network and network solutions to resolve both power flow and voltage issues, and also optimises for embedded generation output

The list of equipment we have deployed for CLNR is:

Equipment		Urban Network Rise Carr	Rural Network Denwick	Heat Pump Cluster Hexham	PV Cluster Maltby
Electrical Energy Storage (EES)	2.5MVA battery at primary substation (EES1)	Rise Carr			
	100kVA battery at distribution substation (EES2)	High Northgate	Wooler Ramsey		
	50kVA battery at distribution substation (EES2)	Harrowgate Hill	Wooler St Mary		Mortimer Road
Enhanced Automatic Voltage Control (EAVC)	Primary substation transformer with on-load tap-changer (EAVC1)	Rise Carr	Senwick		
	Secondary substation transformer with on-load tap-changer (EAVC2)	Darlington Melrose	Wooler Bridge		Mortimer Road
	Regulator (EAVC3)		Hepburn Bell and Glanton		
	Switched capacitor bank (EAVC4)		Hedgeley Moor		
	LV main distributor regulator (EAVC5)			Sidgate Lane	
Real-Time Thermal Rating (RTTR)	Primary substation transformer	Rise Carr	Denwick		
	Secondary substation ground mounted transformer	Darlington Melrose High Northgate	Wooler Bridge Wooler Ramsey	Sidgate Lane	
	Overhead lines		2 locations at 66Kv 4 locations at 20Kv		
	Underground cables EHV	Rise Carr			
	Underground cables HV	Rise Carr			
	Underground cables LV	Darlington Melrose			
Grand Unified Scheme (GUS)		GUS central controller			
		14 GUS remote distribution controllers (RDC)			
		GUS data warehouse			
		Demand response system integrated into GUS control			
Monitoring		70 instance of monitoring equipment (of three different types) at a range of different network locations			
		iHost data warehouse			

Table 1: List of equipment deployed for CLNR

The customer trials, interviews and subsequent analysis are documented in:

- CLNR-L246: Developing the smarter grid: the role of domestic and small and medium enterprise customers; and
- CLNR-L247: Developing the smarter grid: the role of industrial and commercial and distributed generation customers

The network, storage, and combined solution trials and subsequent analysis are addressed in this report.

To demonstrate this range of solutions, we established four test-bed networks:

1. Rise Carr, Darlington (County Durham). On the 6kV network served from Rise Carr primary substation:
   - » We installed a 2,500kVA/5,000kWh EES unit, connected via a step-up transformer to the primary substation 6kV busbar
   - » At Darlington Melrose secondary substation, we established a similar set-up to that at Mortimer Road, by changing the existing 6100/433V transformer for a unit with an on-load tap-changer, and installed a 50kVA/100kWh EES unit at the remote end of one of the LV feeders from that substation
   - » At High Northgate secondary substation, we installed a 100kVA/200kWh EES connected to the substation 433V busbar
2. Denwick (North Northumberland). On the 20kV network served from Denwick primary substation, we focused on two feeders serving the area around Wooler. These two feeders run in parallel to a firm busbar at Hedgeley Moor Switch House, where we had previously installed a mechanically-switched capacitor bank. As on many rural networks, these two feeders support about 2MW of load before they reach the switch house
   - » In Wooler town, we did much what we had in Darlington, fitting Wooler Bridge substation with a transformer with an on-load tap-changer and a remote 50kVA/100kWh EES unit, and connecting a 100kVA/200kWh EES to the 433V busbar at Wooler Ramsey
3. Hexham (Northumberland). At the Sidgate Lane substation we tested the flexibility afforded by secondary transformer RTTR and secondary (feeder) EAVC. At this location we monitored voltage, power flow and power quality the feeder chosen served a group of customers with a high take up of heat pumps
4. Maltby (Rotherham, South Yorkshire). Here, we replaced the existing 11,000/433V transformer at Mortimer Road 45548 substation for a unit with an on-load tap-changer, and installed a 50kVA/100kWh EES unit at the remote end of one of the LV feeders from that substation. The feeder chosen served a group of customers with a high take-up of solar PV

We installed new smart RTUs at every point where we controlled something, as a deliberate design decision to give us fall-back local control and also to interface to the area controller. This gave us:

- Both primary substations, to drive the existing OLTC and, at Rise Carr, to drive the EES
- The three secondary substations with OLTC
- The existing capacitor bank at Hedgeley Moor and an existing 20kV regulator at Hepburn Bell, on the alternate feed from Hedgeley Moor into Wooler town
- The two secondary substations with a 100kVA EES
- The three remote 50kVA EES

These smart RTUs built on the latent capability of modern SCADA outstations, to provide significant local intelligence within the substation. Features included:

- Measurement processing
- Local voltage management, i.e. identifying excursions beyond user-defined voltage limits and requesting an appropriate intervention
- Thermal modelling, implementing the transformer RTTR algorithm described in detail later, to work out the real-time capability in amps
- Local thermal management, i.e. comparing the real-time capability calculated in the modelling module to the present demand, to identify excursions beyond that calculated RTTR limit and requesting an appropriate intervention
- Device management, providing the intelligence to manage the interface to active controls like OLTC and EES. This includes protocol conversion, but also extends to providing safe modes and set-points when reverting to local control on loss of communication with the area controller
- Coordination and mode management, arbitrating between local voltage and thermal management, and managing the interface with the area controller

Those smart RTUs, and a monitoring suite described in more detail in the monitoring section of this report, were connected by VPN over PSTN to an area controller sited adjacent to our northern system control centre. The monitoring showed us not just what happened at the point of control but also, in conjunction with a state estimator, allowed us to gauge network conditions all the way from the primary transformer to the end of the LV network.

A schematic of the entire system and the associate information flows, depicted as per the smart grid architecture model, is shown in appendix 4.

When managing voltage, we wanted to understand what was happening at the point of delivery to our customers, which is the only point on the network where voltage really matters. We managed this by combining a little monitoring with a state estimator which covered both HV and LV networks. We used points of control at many voltages, specifically: LV (50kVA and 100kVA EES); HV (secondary OLTC, regulators and capacitor banks); and EHV (66/20 and 33/6 primary transformers), but all were managed by reference to what was happening at LV.

Similarly, the combination of monitoring and state estimation allowed us to manage power flows across the whole network from LV main to primary transformer, again crossing the voltage levels to use (for example) LV connected storage to offload a 33kV connected primary transformer.

We chose the Maltby and Hexham networks partly to create a small initial prototype to test the solutions, but mainly to trial our new solutions on a LCT-rich networks.

We chose the Rise Carr and Denwick networks to demonstrate that similar solutions can address different circumstances. Rise Carr is a compact urban network, while Denwick is an extended rural system. That these networks run at 6kV and 20kV respectively makes little difference to their construction and operation, as we generally use the same tools for 6, 11 and 20; again, we made this choice to demonstrate how the same techniques apply at different voltage levels. If a solution works on an urban 6kV network and a rural 20kV network, we can be confident that it will work almost anywhere.

All our trials were aimed at providing useful information to practising power systems engineers. We have produced a wealth of material on how to specify, procure, install and operate the equipment we have installed.

This document is primarily aimed at whole-system design, illustrating how the various non-network and network solutions we have deployed can be used singly and in combinations, to alleviate network constraints.

Our academic partners were a great help in developing the test scripts we ran on these test bed networks. There is a significant difference between the commissioning tests we normally use to prove whether something works, and the trials we have run to understand how it works, and how it can be applied in different situations.

Our academic partners developed a VEEEG (validation, extension, extrapolation, enhancement and generalisation) method, designed to quantify the benefit of any solution or combination (see figure 2).

Firstly, we created pre-trial mathematical models of each solution, to assess their likely benefits. These were then used to prioritise the field trials, with credits being applied to each test script according to its contribution to the overall learning.

The field trials were used mainly to validate the models, which were refined into a post-trial version. This recognised issues such as the quirks of real-world monitoring and control schemes, to give a much more realistic view of how these solutions behaved and interacted.

These models were then used to fill in the gaps around the field trials, allowing us to synthesise scenarios which we could not test directly. For example, when we drove DSR from the CLNR control system, those customers were not in the test bed areas: through VEEEG, we were able to synthesise what would have happened if everything were in the perfect place. VEEEG also helped us project different scenarios for customer take-up of new technologies. Therefore, we have great confidence that the benefits we have assessed for each solution are robust across a much wider range of scenarios than our field trials.

This approach is important learning in itself, and could usefully be applied to other research programmes.

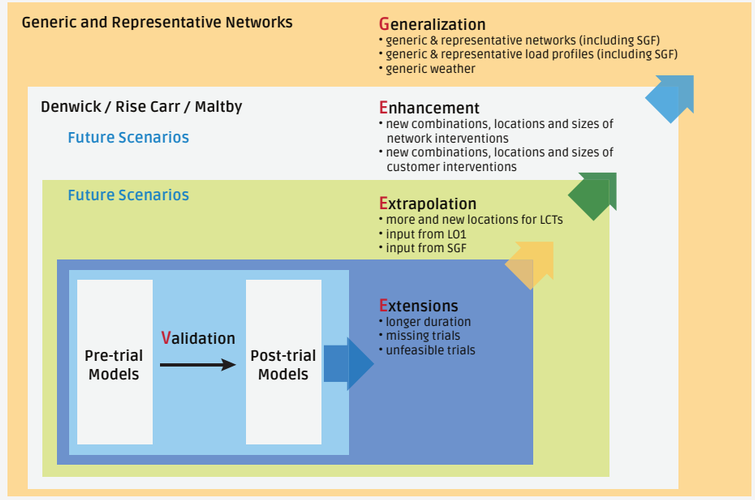


Figure 2: VEEEG methodology

4. SAFETY CASE

Northern Powergrid, in common with all DNOs, has business as usual processes to ensure adherence with legal, regulatory and moral obligations to operate the business safely, reliably and efficiently. These processes will be applied to any BAU roll-out of the 'smart' Methods from CLNR and were applied to all activities including the planning and execution of the CLNR activities.

> "For the trials themselves, any identified overload and over-voltage have largely been designed out. The selected test networks are sufficiently robust that, even with significant system failures, voltage and thermal limits will not be exceeded.

Prior to the deployment of novel assets and processes within the Northern Powergrid distribution system and in common with BAU processes, the proposed arrangements were subject to an electrical design study as well as an operational risk assessment for the proposed equipment. These BAU processes Northern Powergrid continue to operate a safe, reliable and efficient electricity distribution network. The key stages of planning the deployment of CLNR assets are detailed below:

Ensuring safe procedures for on-site installation, operation and maintenance:

- Preventing dangerous thermal overload[10]
- Preventing under/over-voltage. The voltage limits in ESQCR remain an absolute legal requirement. Therefore, we will design the system to run within those limits, and install back-up systems consistent with the industry standard ENA Engineering Recommendation G59, i.e. set to trip at statutory limits +4%/-7%

For the trials themselves, identified overload and over-voltage have largely been designed out. The selected test networks are sufficiently robust that, even with significant system failures, voltage and thermal limits will not be exceeded. However, looking ahead to real-world deployment, these new techniques will by definition be applied to potentially stressed networks. Therefore safety has to be designed in.

BS EN 61508 is an international standard covering safety-critical systems. Broadly speaking, this requires that either:

- The control system (in this context of the smart grid, active network management schemes) is verified against formal methods. It is not practicable to test complex systems for safety, therefore best endeavours must be made to build in robustness and design and build out errors and instability; or
- Simpler and more robust back-up protection, which can be verified, is provided independent of the main control scheme

While many schemes degrade gracefully[11], it would not be prudent to rely on them entirely (and, if we did, we must formally assess them against BS EN 61508). The philosophy applied for CLNR, and the one we intend to apply as BAU, has been to provide additional discrete back-up protection. It seems to us to be reasonably practicable to invest in separate measures to ensure safety, not least because such systems:

- Are much simpler than the main control scheme, and can therefore be more easily and more effectively formally assessed against BS EN 61508 and with much greater cost-efficiency; and
- Defend against failures anywhere in the chain, whether monitoring, control, response (e.g. of DSR or storage) or communication

While we have had minor issues with nuisance tripping, we have seen nothing in our trials to change our stance. We note that similar trials, like the UKPN FPP, have also deployed back-up protection against thermal overload.

In each case failures may arise anywhere in the monitoring, control, response and communication chain leading up to the desired intervention, but the protection we have fitted provides suitable additional control measures to defend against all identified risks within the CLNR chain. We intend to continue to fit such protection in the future smarter distribution system.

In CLNR, we have installed back-up protection for:

- Over-voltage from OLTC runaway
- Over-voltage from EES runaway
- The dangers of islanding EES (the same as for any source of energy, as laid out in ER G59); and
- Where not already fitted, transformer thermal overload from failure of EES or DSR

If anything, some of the failure modes of the CLNR area controller confirm the need for such additional discrete back-up protection. On occasions, processes within the area controller have stopped, without then placing the active control devices into a default safe state. This would have placed the network at risk of overload.

[10] Here, we're looking at current from normal demand. Running assets harder, i.e. hotter, marginally reduces their capability to handle fault current, but this is normally already taken care of in the fault rating assigned to those assets, because it's calculated on the basis of running at design temperature limits

[11] For example, both the Siemens and Smarter Grids Solutions offerings:
- Correct for loss of monitoring (the Siemens offering also carries out a detailed validation of each analogue, and substitutes where required);
- Correct for lack of response;
- Correct at the centre for loss of comms;
- Correct at the remote end for loss of comms by going into a safe autonomous mode

However, both are:
- Susceptible to plausible but incorrect values;
- Complex computer systems, and therefore not free from failure;
- Designed and configured by humans, and therefore not free from error

We have also ensured during design and deployment that all sites with active components (EES, OLTC, etc.) have relevant alarms back to the main SCADA system.

It can be seen that within CLNR we have not fitted back-up protection for a failure of EES or DSR leading to thermal overload of lines or cables, because design ratings cannot be exceeded in those trials. It is important to recognise that CLNR was a tightly-bound trial, and that we need to review the safety case for BAU applications beyond those initial test cells.

For BAU, we intend to use standard relays (the ANSI #49 overload curve) to enforce static circuit ratings on lines and cables, and standard winding temperature indicators to enforce real-time ratings for major transformers. These all have a time delay consistent with the characteristic of the relevant asset, to reduce nuisance tripping. As noted above, this protects against failures anywhere in the chain, whether monitoring, control, communications, or the response of the real power service (EES, DSR, etc.).

Even if we assume that we will review circuit ratings in light of what we have learnt in CLNR, and even given the delay built in to the relay curve, deploying such back-up protection creates a risk of customer disconnection. This is clearly a preferred option rather than potentially injuring staff or members of the public.

Where we roll-out OHL RTTR, irrespective of the customer base, we must do what we reasonably can to avoid the risk of overload. Mitigating actions include:

- Calibrating the RTTR algorithm for the required level of risk. Since the ER P27 tabulated ratings give a higher risk of exceedance than the 0.001% intent of that document, we might set the RTTR algorithm to meet the spirit of ER P27 and give less risk than we presently own
- Providing for graceful degradation, e.g. having local intelligence, which reduces generation output to a safe level if the area controller or the communication link fails. Note that this option is not available for DSM, because the fail-safe would be a sustained reduction in demand, which is impractical
- Increasing clearance at, or undergrounding, high-consequence spans like main-line railways or high-speed road crossings
- Applying dynamic settings for the back-up protection. For example, UKPN's flexible plug and play project measures wind speed at the source primary substation, and uses this in a thermal model on the feeder relay, which uses the output of that model in the ANSI #49 thermal overload function described previously

Applying CLNR learning to this shows that we can rely on wind speed monitoring to reflect what's happening at remote sites. We have correlated observed wind speed at Denwick primary substation to the two sheltered sites at Broxfield and Scar Brae (note that the gauges were 8m up at Denwick and 4m up at the other sites):

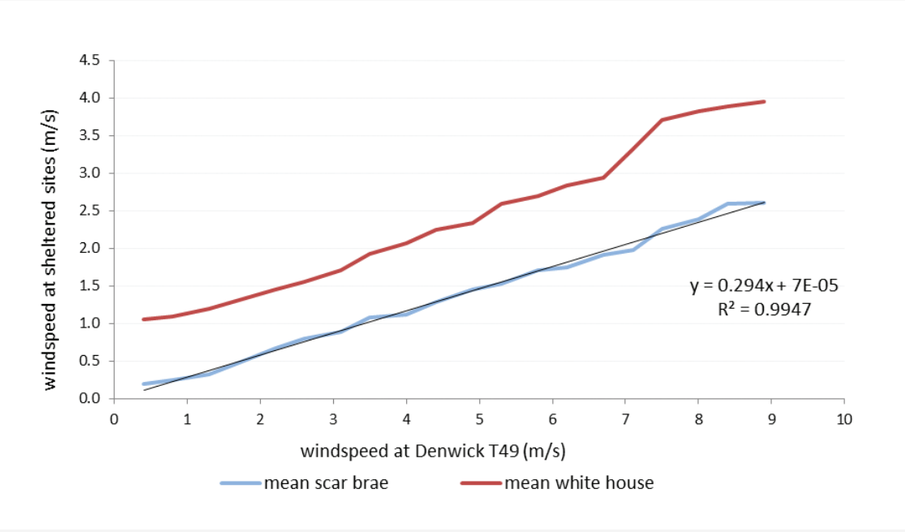


Figure 3: Correlation of observed wind speed between sites

> Applying CLNR learning to this shows that we can rely on wind speed monitoring to reflect what's happening at remote sites.

This suggests that we can estimate wind speed at a remote sheltered site as about 30% of the wind speed at the base site: it might be prudent to adopt a lower figure (say 10%) initially and verify through monitoring. This builds on other work, e.g. UKPN FPP and Strategic Technology Programme (STP) 5167 Enhanced ratings for OHL connections to wind farms, because it specifically addresses the sheltered sites not covered in that work.

Some of this requires a systems engineering approach, for example:

- Modifying the area controller so that it issues set-points regularly, whether or not they've changed, to confirm to the remote ends that the controller is still working
- Using the same algorithms in area controller and feeder protection relay

All the above is consistent with our prime objective of doing everything reasonably practicable to avoid danger. There are some quirks of the drafting of ESQCR which have always needed review, but CLNR specifically highlights:

- The absolute sufficiency requirement of regulation 3; and
- The requirement of regulation 17 that the height above ground of any overhead line, at the maximum likely temperature of that line, shall not be less than that specified in the regulations

For overhead lines, the maximum temperature depends upon load and weather conditions, neither of which can be predicted perfectly. Therefore, we need to agree a practical basis on which to assess what we mean by 'likely' conditions and therefore what would be 'sufficient'.

5. DESIGN DEMANDS

To understand how to design a distribution network, we first need to understand what we're designing it to do. In this paper 'demand' will be used to refer to the requirements placed by customers on the network, so that both load and generation can be considered as demand.

This section largely summarises some of the conclusions of:

- CLNR-L185 Review of the distribution network planning and design standards for the future low carbon electricity system
- CLNR-L216 Baseline domestic profiles insight report
- CLNR-145 Commercial arrangements – phase 2 report
- CLNR-L098 CLNR Industrial and commercial customer DSR trials report

5.1. Modelling and monitoring

It's fair to ask the question of why we need to estimate demands when we can measure them, particularly as smart meters are rolled out. The answer is:

- It will take a while for the smart meter roll-out to be 99% complete
- We need to resolve access to data for customers without smart meters. The main gap is advanced metering for what was profile classes 5-8 (non-half-hourly meters with maximum demand registers, broadly equivalent to the 50-100kVA range), which account for about 5% of demand in Northern Powergrid (Yorkshire) and nearly 10% in Northern Powergrid (Northeast) license areas
- We will not have metering data for houses which have not yet been built, or for LCTs which customers have not yet bought
- As SMEs differ so widely, monitoring is essential, at least for existing sites:
  - At the customer, once advanced/ smart metering data is available
  - At the substation (correcting for seasonal changes in customer behaviour), then adjusting for other 'known' customers

Whether we use a full probabilistic approach, such as the expected energy not supplied method laid out in ACE51, or a deterministic /mechanistic approach derived from such probability studies, we need an estimate of the demand against which we plan to provide capacity from the distribution system.

Two approaches are recognised in present planning standards, specifically:

- DEBUT and
- ADMD

Both techniques are valid, and both recognise that customers behave differently enough that their maximum demands diversify down with increasing numbers of customers. To illustrate the point, for individual customers we should design their service connection for something like 15kW simultaneous demand, for a shower, a kettle, the radio and a few lights; for a dozen customers at the end of a housing estate, they're unlikely to be taking a shower at the same time, so we should design that tail-end mains cable for 2.5-3.0kW; as the size of the group increases, it becomes even less likely that customers' short-term peaks will coincide, so the mean demand continues to decline.

The DEBUT approach assumes that customer demands follow a normal distribution, so it uses the mean and standard deviation of a large sample of customers. The impact of the standard deviation declines with greater numbers of customers.

ADMD (after diversity maximum demand) uses a simple linear forecast, with a fixed part representing that single customer demand and a variable part representing the mean demand across a large number of customers.

The pros and cons are that:

- The DEBUT approach better helps understand the coincidence between the electricity demands of different customers, as it contains coefficients for each half-hour of the worst-case day. This allows us to add up coefficients for each half-hour, rather than simply adding the highest demand at any point in the day; and
- The ADMD approach better reflects the demands for groups of less than a dozen customers, because of its significant fixed element

Method

The academics at DEI have subjected half-hourly consumption data from customers with smart meters to rigorous statistical analysis, as detailed in their reports.

We have derived data to update the DEBUT approach. The new DEBUT coefficients follow the existing approach of assessing mean and standard deviation. The benefit of CLNR is that the sample group for 'normal' domestic customers is much larger than that used to derive the present coefficients.

We have also reviewed the present ADMD approach by applying a much more scientific approach. Specifically, we have sampled the observed data to synthesise the aggregate demand of groups of customers of varying sizes. For several different groups of customers this shows that mean demand follows a power law around the fifth root of the number of customers.

5.2. Underlying domestic load

5.2.1. DEBUT

The CLNR ACE 49 Report has broadly defined domestic customer types according to their electricity tariff (e.g. unrestricted, restricted), type of heating (e.g. water, space), electrical appliances (e.g. electric cooking), electricity consumption (i.e. low, medium, high), etc. However, the demand for electricity on the distribution system is changing as new technologies become an integral part of customers' lifestyles and behaviour. In this context, there is a need to consider the applicability of the customer types of the ACE 49 Report to represent the characteristics and behaviour of present-day customers. To this objective, the CLNR project has segmented domestic customers according to socio-demographic attributes that shape their energy use. Whilst any other cut of the datasets would have been possible, for instance by Mosaic[13] group, the CLNR project was interested in exploring the social and anthropological drivers underpinning domestic energy use. Thus, the domestic customer groups[14] considered in the project are presented in Table 2.

Customer attribute	Customer type label
Ages of the household members	Dependant: household includes at least one child aged < 5 and/or adult aged ≥ 65years Non-dependant: all members ≥ 5 and / < 65 years
Household income	Low income: ≤ £14,999yr Medium income: £15,000yr – £29,999yr High income: > £29,999yr
House tenure	Renter Non-renter
Thermal performance of the building	Low thermal efficiency Medium thermal efficiency High thermal efficiency
Rurality	Rural Rural off-gas grid Suburban Urban

Table 2: Domestic customer group types

The CLNR project has used the data collected from the customer field trials to produce a generalised set of load curves for different types of domestic customers that can be applied within the current ACE 49 framework for the estimation of the design demand in LV radial distribution systems. Figure 4 presents an overview of the load curves of the different domestic customer types considered in the smart meter trials of the CLNR project.

[13] Experian, 2009. "Mosaic United Kingdom, the Consumer Classification of the United Kingdom", Experian, 2009. http://www.experian.co.uk/assets/business-strategies/brochures/Mosaic_UK_2009_brochure.pdf

[14] CLNR-RE002, 2011. "Protocol for Population of Domestic Test Cells" Report RE002 of the Customer Led-Network Revolution project, September 2011

Once we have normalised the data, the mean demand factor graph and statistical analysis show that, with exception of rural off-gas grid, the demand shape is effectively the same for all customer sub-groups, and the only important modifying factor is overall consumption, which is easily measured.

This is backed up by statistical analysis of the dataset. For each customer group, our academic partners calculated the 95% confidence interval of peak demand. These values for each group overlapped, suggesting no statistical difference between them, except for the high income group.

We can also compare the old (ACE 105) DEBUT coefficients to the new values we have calculated. Looking at the headline mean kW figures, we're looking at a reduction of 42%, from 1.58kW to 0.91kW.

If we follow through the ACE49/105 approach, and correct for the lower annual consumption in CLNR (3,532kWh against 4,709kWh, down 25%), we see a change of 24%, from 0.336 kW/MWh (ACE 105 URMC) to 0.257 (CLNR TC1a average).

This suggests that annual consumption has fallen by about 25%; that the load curve has flattened, reducing kW/MWh by about 25%; giving an overall reduction in peak power above 40%. Therefore, we see two changes in customers' practices:

- They use less energy overall, due in part to buying more energy efficient appliances; and
- They use energy more evenly through the day and year

5.2.2. New ADMD

We propose a new method of deriving ADMDs. Instead of the subjective formula presently used, we have analysed how group demand changes with the number of customers. Analysis by DEI has synthesised 1,000 groups of customers, each ranging in size from one to 100, by sampling the CLNR customer dataset. From this, we have calculated the mean demand at each size of group, and explored what curve best fits those results. We have found that a power law gives a goodness of fit (R2) above 0.9.

Figure 6 shows compares the new ADMD to the present (ACE 105) ADMD, in each case for the average domestic customer. The new ADMD follows the form $4.6n_{-0.22}$; the old ADMD follows the form 8+1.5n:

It can be seen that the new figures are a little higher than the old ones. This is mainly because the power law approach diversifies more slowly than the conventional method.

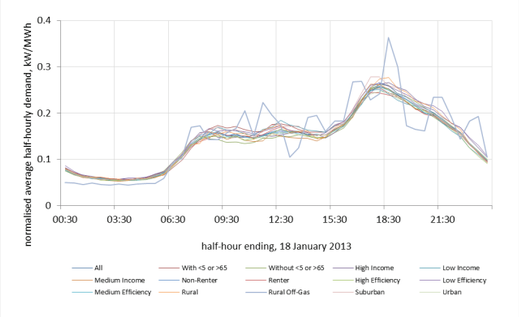


Figure 4: Customer demand by domestic sub-groups

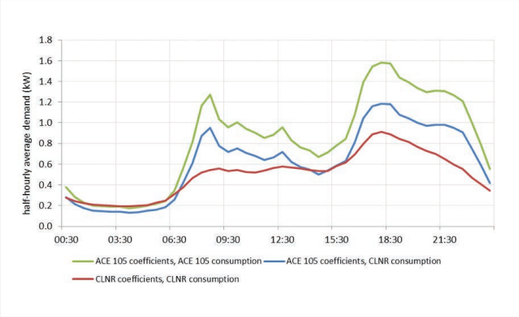


Figure 5: Domestic design demands

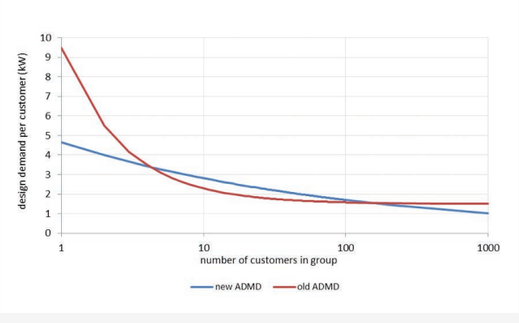


Figure 6: Comparison of ADMD methods

5.3. Solar PV

5.3.1. DEBUT

The dataset representative of the operating behaviour of solar photovoltaic installations has been extracted from CLNR's enhanced profiling of solar PV customers (TC5) and the within-premises balancing for solar PV customers with in-home displays (TC20IHD).

Moving towards a low carbon energy system of the future, the increasing and significant presence of LCTs (e.g. solar photovoltaic and wind) in the LV networks are likely to cause voltage regulation (and, in the extreme, thermal) problems during coincidence of low daytime demand and high LV solar photovoltaic or coincidence of low night-time demand and high LV wind. Thus, designing the electricity distribution system to accommodate conditions of peak demand may not be sufficient as network voltage limits may be breached during such conditions. Thus, there might be a need consider conditions of low load demand (e.g. summer season) and high DG (e.g. solar photovoltaic during summer season) in the planning and design of distribution networks for a low carbon future.

To this aim, an analysis has been performed to explore the impact of coincidence of high LV solar photovoltaic with low demand both during the summer period on the design demand and voltage regulation. Figure 7 shows the average household load, solar photovoltaic generation and net load (i.e. load minus generation) for domestic customers with solar photovoltaic installation for the minimum load day during the summer period.

Figure 7 depicts the household net load for the minimum-load day during the summer period. Positive net load values suggest that the household load is greater than the solar photovoltaic power generated by the household installation. Negative net load values indicate that the solar photovoltaic power generated over and above load with the surplus being directly exported to the distribution network. It can be seen that the maximum solar photovoltaic power exported to the network is 1.40kW in the half-hour ending 12:00.

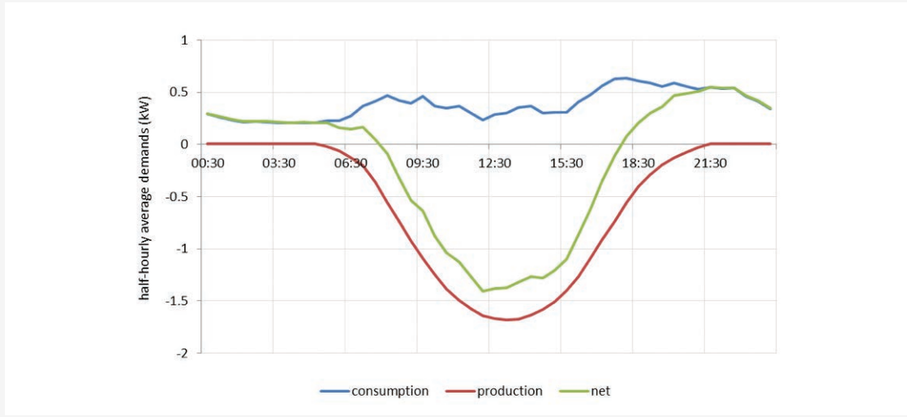


Figure 7: PV design demands

Case study

The analysis has then explored the impact of coincidence of high LV solar photovoltaic with low demand in the operation and development of electricity distribution networks. The network analysis has been performed on the Maltby electricity distribution network of the Northern Powergrid licence area. The analysis is performed for the minimum-load day during the summer period for domestic customers characterised by an annual energy consumption of 3,532kWh as in the smart meter trials. Table 3 details the minimum levels of headroom and legroom available across the circuits of the five feeders that form the Maltby electricity distribution network and for different penetration levels of solar photovoltaic installations. These levels of headroom and legroom are attained for the most overload network circuits for a specific half-hour of the minimum-load day in the summer period. The penetration level of solar photovoltaic is defined as the number of customers that have solar photovoltaic installations over the total number of customers present in the network. Based on the CLNR customer field trials, the installed capacity of a domestic solar photovoltaic installed was considered to be equal to 3.68kW.

Penetration level (%)	Thermal headroom (%)		Voltage legroom (%)	Voltage headroom (%)
	Feeders	Transformers		
0%	63%	73%	59%	n.a.
10%	66%	76%	61%	27%
20%	66%	77%	55%	23%
30%	67%	77%	64%	22%
40%	55%	75%	64%	-3%
50%	37%	64%	64%	-5%
60%	29%	54%	64%	-2%
70%	25%	44%	64%	-12%
80%	7%	34%	64%	-21%
90%	-6%	24%	64%	-41%
100%	-16%	14%	64%	-28%

Table 3: Impact of domestic solar photovoltaic on circuit headroom and legroom for the Maltby electricity distribution network in the minimum load day during the summer period

Table 3 shows that the increasing presence of domestic solar photovoltaic installations in the Maltby electricity distribution network has a relatively significant impact on thermal and voltage headroom and legroom of network assets. It can be seen in Table 3 that the voltage headroom corresponds to the first type of headroom to be breached as the network voltage rises over and above the statutory limits. For instance, the Maltby network is capable of accommodating a maximum penetration level of solar photovoltaic of around 30% without observing voltage rise issues. It is noted in Table 3 that the overall decrease in voltage headroom, as the penetration level of solar photovoltaic rises, presents a lumpy behaviour that is driven by the phase to which the solar installation is being deployed. Figure 8 details the level of voltage headroom across the three different phases for every per cent level of solar photovoltaic present in the network.

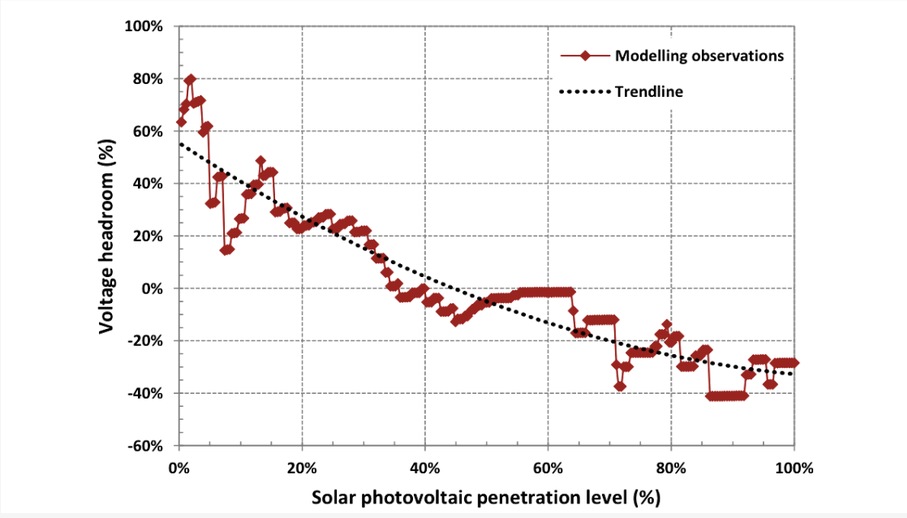


Figure 8: Voltage headroom

The trend-line curve in Figure 8 indicates that in the long run there is an overall reduction on voltage headroom (or increase in voltage rise) as the penetration level of solar photovoltaic in the network increases. Nonetheless, the modelling observations curve shows that in the short run the voltage headroom slightly oscillates as new solar photovoltaic customers are connected in the network. In DEBUT computer program, customers are connected at different phases and therefore subjected to slightly different phase voltages leading to the oscillation observed in Figure 8 that reflects the maximum voltage of the three phases.

It can be also seen in Table 3 that the coincidence of high solar photovoltaic with low demand during the summer period has little effect on the voltage legroom as the increase of power in the network from solar photovoltaic distributed generators will not cause significant drops in voltage.

It is observed in Table 3 that at high-penetration levels of solar photovoltaic (e.g. 80% to 90%), the thermal headroom of feeders also becomes negative indicating that some network circuits are overloaded. Thus, the network is not capable of accommodating more solar photovoltaic installations without reinforcing network circuits.

The coincidence of high solar photovoltaic with low demand during the summer period may cause voltage headroom constraints in the network depending on the penetration level of distributed solar photovoltaic generation, network characteristics and topology. These voltage headroom constraints are driven by the surplus power of solar photovoltaic DG being injected in the network at times of low demand. The inclusion of a network study for the summer period should be considered during a future review of ACE 49 Report to ensure the robustness of the network design against voltage rise.

5.3.2. Declared capacity and observed output

Solar PV output is a purely physical phenomenon, and depends only on the size of the panel and its orientation towards the sun. There are no human factors involved. Therefore, we need to understand how the output relates to capacity, for individual installations and for groups.

We have carried out a bottom-up analysis of this effect, by synthesising groups of customers from sampling our dataset:

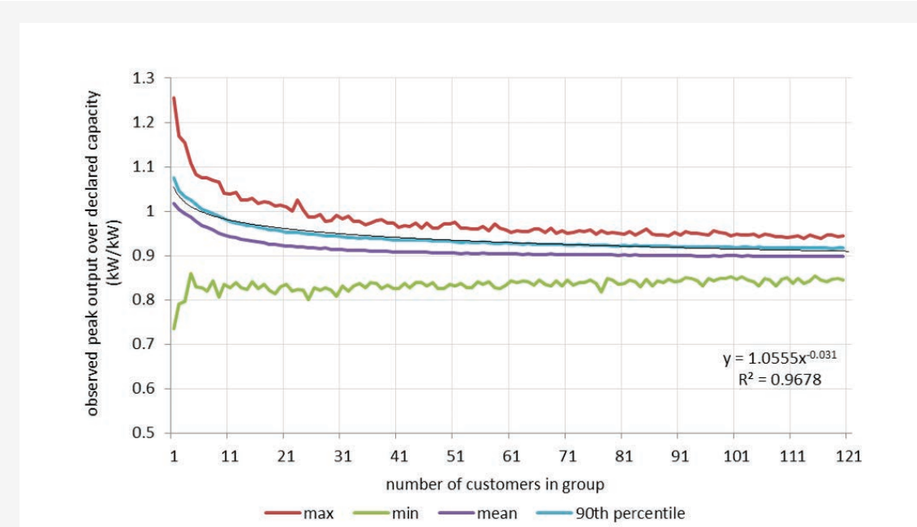


Figure 9: PV observed output

This shows that:

- At individual installation level, there is a wide spread of observed output against declared capacity. WPD's LV network templates project also found that installers of LV PV have adopted varying approaches to determining the peak ratings included in their (retrospective) connection notice. In CLNR, we have found that these errors are largely symmetrical, and cancel out with increasing numbers of customers
- The mean output approaches 90% of nominal capacity, and the 90th percentile (broadly equivalent to the ACE 49/105 approach) gives a very similar number. WPD's network templates project gave a top-down estimate of 80%

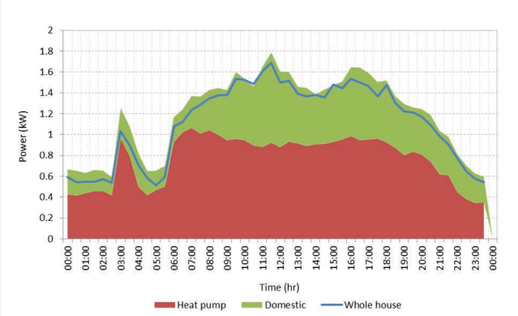


Figure 10: Average kW demand components

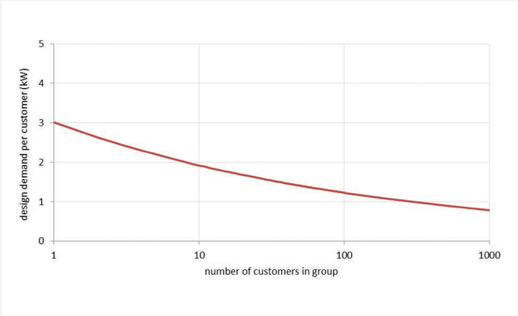


Figure 11: Observed HP demand mild winter

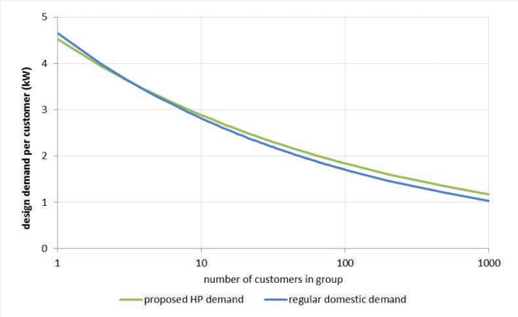


Figure 12: Proposed HP demand severe winter

5.4. Domestic heat pumps

5.4.1. DEBUT

The dataset representative of the operating regime of the heat pumps has been extracted from the test cell TC3 (i.e. 'enhanced profiling of Heat Pumps') of the CLNR field trials.

We can break out the components of average kW demand as in Figure 10.

There is some noise in these figures, because the customer groups for each measurement don't match exactly, but the overall impression is clear: the heat pumps run steadily through the day at a 1:2 duty cycle, lifting the household demand by about 1kW. The morning spike in heat pump demand is outweighed by the increase in general household load through the day into the evening. Note that these figures are the mean for a group of 200 to 300 customers, so smaller groups will be less diversified and show a higher demand.

In a colder winter, these heat pumps will run at a higher duty cycle to maintain the same internal temperature for a lower external temperature. If we assume that customers are looking to maintain an internal temperature of 20°C, and we have observed external temperatures of -5°C in the mild winter of 13/14, then the figures we have measured reflect a 25°C temperature differential. If we take a planning case of an external temperature of -15°C, that gives a 35°C temperature differential.

Newton's law of cooling shows that, between these two scenarios, the heat loss will increase by 40%. Making an arbitrary allowance for the lower efficiency of the heat pump, because it's working harder and starting from a lower point, this suggests a planning assumption of a 50% increase in electrical demand from the heat pump above what we have observed. This could be met by running a 3kWe unit at a higher duty cycle: it seems unlikely that we will see widespread sustained use of auxiliary heaters, except perhaps the extreme (but credible) case of cold-load pick up[15].

5.4.2. New ADMD

Again, we have calculated new ADMD figures by sampling the dataset. The new ADMD curves for the heat pump alone suggest:

This is entirely consistent with a group of customers with 3kWe heat pumps: when we look at any one customer, we will see that same 3kW peak demand. This also shows that, in the mild winter of 13/14, demand diversifies rapidly away: with as few as 10 customers, it's below 2kWe. This is consistent with a duty cycle of around 2:1, so customers are not running their heat pumps flat out, and the consequent cycling of the units spreads the group average demand.

As noted in the discussion of DEBUT coefficients for heat pumps, we should increase the observed values by around 50% to compensate for cold winters. Applying this to the ADMD values shown above gives the curve below.

Further work is needed to validate this, but we will not be far wrong if we assume that customers with heat pumps have twice the demand of regular domestic customers.

> "The morning spike in heat pump demand is outweighed by the increase in general household load through the day into the evening. Note that these figures are the mean for a group of 200-300 customers, so smaller groups will be less diversified and show a higher demand.

[15] Cold-load pick-up is a well-known and often-observed phenomenon on networks serving customers who have electric heating. After a network fault has interrupted the supply for a few hours, customers' premises cool down. When we restore supply, the electric heating in all those premises will come on at near full power to warm back up again. This loss of diversity in demand significantly increases the load on the network

5.5. Electric vehicles

The dataset representative of the charging regime of electric vehicles has been extracted from the test cell TC6 (i.e. 'enhanced profiling of Electric Vehicles') of the CLNR customer field trials. Figure 13 displays the mean demand 'P' for electric vehicles in the peak load day during the central winter period.

It can be observed in Figure 13 that the power peak consumption attributed to the domestic charging of electric vehicles mostly occurs in the evenings and overnight reaching a magnitude of around 3kW in the half-hour ending 22:00.

We have calculated new ADMD values for these customers, but the results are inconclusive.

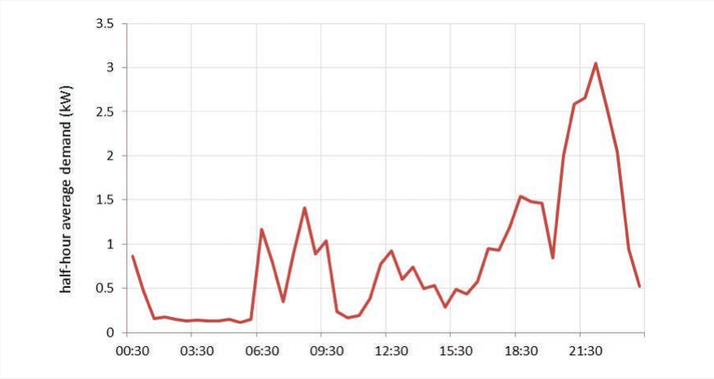


Figure 13: Mean demand 'P' for electric vehicles

5.6. Impact of time of use tariffs

The CLNR project also set up test cells to trial novel commercial arrangements to encourage customer flexibility such as domestic ToU tariffs.

In this context, the analysis establishes a comparison between the load curves representative of domestic customers in the ACE 49 Report, domestic smart meter customers (i.e. TC1a) and the load curves of domestic customers observed in the test cell 9a (TC9a) CLNR customer field trials. The TC9a dataset represents pure ToU tariff for domestic customers and covers a full year period, from January 2013 to December 2013. For the purposes of this report, the TC9a trials will be referred as ToU trials). The overall ToU tariff used in the CLNR customer trials is composed by three different bands (i.e. peak, off-peak and day) for every weekday. The datasets were then used to determine the proportion of demand in each tariff band. The structure of the CLNR 3-rate ToU tariff is detailed in Table 4.

Tariff band		Time	Tariff (ppu)
Weekday	Peak	16:00-20:00 (Monday – Friday)	12.19
	Day	07:00-16:00 (Monday – Friday)	25.27
	Off-peak	Monday: 00:00-07:00 Tuesday – Thursday: 20:00-07:00 Friday: 20:00-00:00	8.76
Weekend		All-day	8.76

Table 4: ToU tariff time bands

The comparison of the ACE 49, smart meter trials and ToU trials load curves of domestic customers is performed for the peak load day in the central winter period and their respective mean demand 'P' are presented in Figure 14.

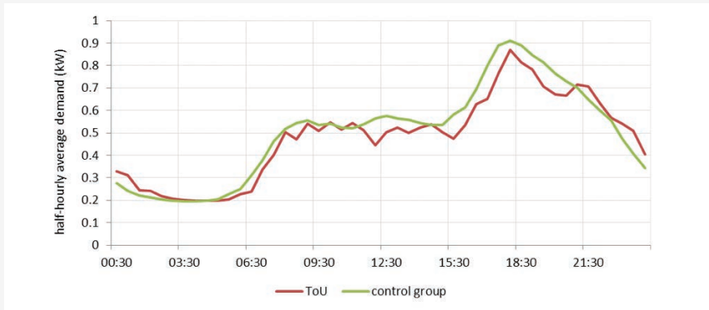


Figure 14: Impact of ToU tariffs

Figure 14 shows the mean demand 'P' for the ACE 49 load curve of a domestic consumer with Unrestricted tariff and Medium Consumption (i.e. URMC), the smart meter trials load curve of a domestic consumer and the ToU trials load curve of a domestic consumer. It can be seen in Figure 14 that the maximum mean demand 'P' for the day under study occurs simultaneously in the three curves at 18:00 hours. The ACE 49 Report indicates that the sample average annual electricity consumption for URMC groups is 4,709kWh whilst the annual consumption for the smart meter trials group was observed to be 3,532kWh and for the ToU trials group was found to be 3,417kWh. Based on these annual electricity consumption levels, the maximum mean demand 'P' decreases from 1.58kW in the ACE 49 curve to 0.91kW in the smart meter trials control group curve and to 0.87kW in the ToU trials curve.

This reduction in the maximum mean demand is only modest and will be overshadowed by other behavioural changes, buying an electric car for example.

6. THE CONTRIBUTION OF GENERATION TO SYSTEM SECURITY

Distribution systems have always been designed to reflect the contribution of generation to security. There are still networks where the primary, and possibly sole, source of power is local generation.

The Great British planning standard, Engineering Recommendation P2 (security of supply) was updated in 2006 to reflect the changing generation mix.

Specifically, Engineering Technical Reports 130 and 131 detail a method of deriving the contribution to system security for both generic generators by primary source (wind, AD, etc.), and also provide a method for bespoke analysis of the output curves of individual generators (and the specific local load curve) to assess the specific contribution to network security.

Given the strong customer engagement element of CLNR, we have taken the opportunity to assess the default values for generation contribution by running more site-specific data through the standard model. We have found that:

- CLNR values for the contribution of wind generation to system security are lower than the existing defaults; and
- CLNR values for small hydro are consistent with the existing defaults

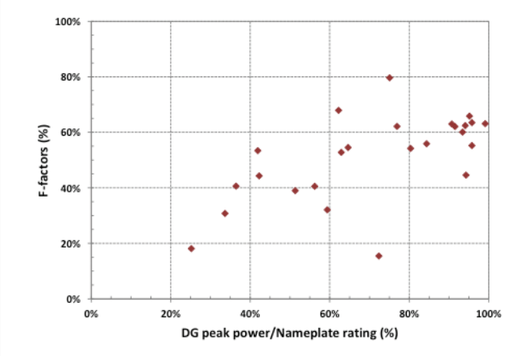
Cases	T_m						
	0.5	2	3	18	24	120	360
ETR130: F-factors for wind farm	28%	25%	24%	14%	11%	0%	0%
CLNR Trials: Average F-factors for wind farm	19%	15%	14%	8%	6%	0%	0%

Table 5: F-factors for wind farms

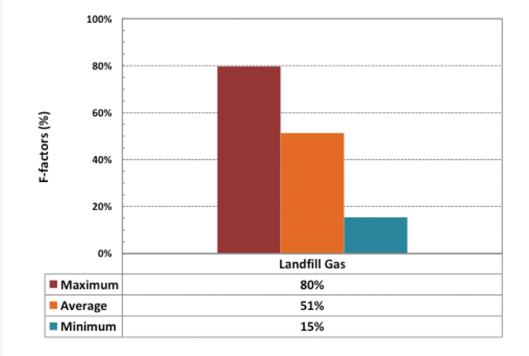
Cases	T_m						
	0.5	2	3	18	24	120	360
ETR 130: F-factors for small hydro	37%	36%	36%	34%	34%	25%	13%
CLNR Trials: Average F-factors for small hydro	32%	32%	32%	31%	31%	27%	21%

Table 6: F-factors for small hydro

The set of F-factors quantified for the 25 monitored DG Landfill Gas sites are presented in Figure 15.



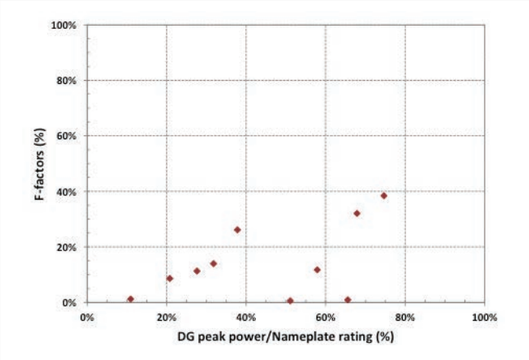
(a) Distribution of F-factors



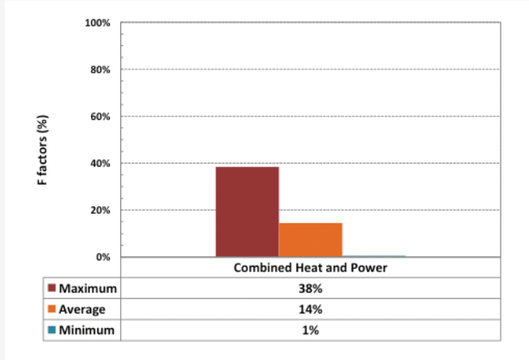
(b) Statistics of F-factors

Figure 15: F-factors for landfill gas sites

The set of F-factors quantified for the 10 monitored DG CHP sites are presented in Figure 16.



(a) Distribution of F-factors



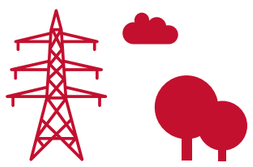
(b) Statistics of F-factors

Figure 16: F-factors for combined heat and power sites

7. OVERLOAD

Having discussed the demands our customers will place on the distribution system, we now turn to a discussion of how those demands may be expressed in electrical terms, and what we are going to do about it.

We start by discussing thermal overload, and then move on to voltage. It is easier to identify thermal constraints than for voltage constraints, as it is clear which asset is overloaded. For both opportunities, the solutions can be tiered and it is possible for real power dispatch in the right place to resolve a number of series constraints.



7.1. Enhanced thermal ratings

The current (power) we can push through an asset is generally limited by the conductor temperature. For most assets, running too hot can damage insulation or other components. Also, overhead line conductors stretch more as they get hotter, causing them to sag below safe clearance. Broadly speaking, higher currents cause higher resistive losses. To dissipate that heat, Newton's law of cooling dictates that the temperature difference between the conductor and whatever surrounds it must rise. Therefore, higher currents cause higher temperatures.

The standards which set out the static ratings the industry currently uses are based on mathematical models which predict conductor temperature under various conditions, because we can rarely measure conductor temperature directly. The output of those models depends upon the functions of the model and the inputs we use.

As part of our work on CLNR we have directly measured actual over head line conductor temperature and the environmental factors that affect it (as well as electrical parameters) in real-time. The data we have gathered has been used to evaluate the standard static ratings that the industry currently uses. We have seen nothing to challenge the functions of the models used in the standards[16], but have challenged the default inputs for cables in particular and for summer peaking loads more generally.

Therefore, we propose no fundamental changes to the present ratings standards, only that system designers take care in selecting parameters, specifically (in each case for winter peaking loads):

- For overhead lines, ER P27 tables are about right
- For underground cables, ER P17 tables are about right, but it is essential to apply the correction factors at the back of the book. For example, we recommend using a default soil thermal resistivity value of 1.5W/K-m rather than the present default 0.9. Using the correction factors in ER P17, this derates cables by about 10%
- For transformers, the ER P15 value of 30% over CMR/IEC 60076 nameplate rating is about right

We will call these updated generic static ratings.

CLNR has also identified the key inputs to these models, as will be discussed in subsequent sections. To understand whether we can defer reinforcement of a high value asset we need to measure those key inputs and run the model again. We will call this a bespoke static rating: if the default values are conservative, which they should be, this analysis should release some capacity in most cases.

Some of these key inputs (e.g. ambient conditions) vary over time, while others (e.g. asset thermal characteristics) are fairly constant. These inputs are discussed in subsequent sections. There will be a few occasions where making decisions in real-time based on working out the rating in real-time adds value, specifically where we can do something with that information, such as issuing set-points to reduce generator output or increase system support from energy storage.

It is only if we are working out thermal rating in real-time that we can accurately call it real-time thermal rating: otherwise, it is a better static rating. We will sacrifice some academic purity in this document by encompassing in RTTR both real-time ratings, which take no account of dynamic thermal response, and also dynamic ratings, which do take account of asset thermal time constants.

In CLNR, we have deployed true RTTR for overhead lines (66kV steel towers and 20kV wood poles), and true dynamic thermal rating for transformers (both primary and secondary) and for underground cables (33kV, 6kV and LV). These real-time ratings have been used in the CLNR control system, in both local mode and the coordinated area control mode, to identify apparent overloads[17] and dispatch DSM (both DSR and energy storage) in response.

We have then also collected and stored environmental data from the real-time systems for subsequent off-line calculation of thermal ratings.

All of these solutions are important. Better monitoring to inform off-line assessment of bespoke ratings is a powerful tool to release latent headroom and, particularly for cables, gives more 'bang per buck' than true RTTR. In addition, only the off-line analysis – looking backwards to predict forwards – gives us a planning rating to inform whether or not we reinforce the system: this holds true whether or not we move from a deterministic approach to a probabilistic one, as either approach needs a forecast. Real-time analysis informs only operational decisions, e.g. whether and by how much to constrain a generator.

This supports the following approach:

- Choose an appropriate model for the asset type
- Run the model on updated generic data to create generic static ratings
- If preliminary analysis suggests a potential shortfall, carry out a detailed assessment for that asset to create a bespoke static rating
- If that bespoke static rating is likely to be exceeded, then introduce active control to reduce the risk of excursion to an acceptable level or, if that cannot be achieved (perhaps because there is no DSM to be controlled), reinforce

7.1.1. Updated planning ratings risk

To inform planning ratings looking forward, both continuous and cyclic, we're forced to look backwards to a probability density function of the risk of exceedance, i.e. of demand at the time exceeding capability at the time.

Such analysis requires a correlation with demand (including the effect of outages), so similar assets serving different customer groups, or on different network configurations, might attract different ratings. This decision would be informed less by attempting to meet an arbitrary 'acceptable' level of risk, and more by identifying the point at which further de-rating has little practical benefit.

The power systems engineer has a duty to make the network as safe as reasonably possible. Generally, this means investing out credible risks until the costs become grossly disproportionate to the benefit. For the specific case of choosing a fixed-planning rating for an asset for which the capability changes with weather conditions, this means reducing the nominal rating until the change in risk exposure becomes much less than the implicit cost of having to reinforce the network.

The Great British legal requirement is a reasonable expression of the moral imperative: we must meet the minimum clearance at 'maximum likely temperature'. The ESQCR use of maximum likely temperature and the over-riding principle of SFARP (so far as is reasonably practicable) are broadly equivalent in implementation, i.e. we do not have to protect against every conceivable permutation, but we do have to do what we reasonably can to avoid breaching safety clearance.

It is worth distinguishing between excursion and exceedance. A reasonable approach is laid out in ER P27 for the primary system, where the headline rating is for a 3% excursion, i.e. real-time capability is less than nominal steady-state rating for 3% of the time. However, the risk of exceedance, i.e. real-time capability is less than real-time loading, is as near zero as makes no practical difference. To calculate exceedance, we correlate load and capability, as times of high load are often the same as times of high capability, and times of low capability are often the same as times of low load.

In CLNR, we have developed a tool to correlate ambient conditions and the load curve to calculate exceedance. This confirms that flatter load curves lead to lower ratings.

In calculating excursion, we should also take into account the thermal time constant of the relevant asset. This would permit infrequent short current excursions, as they would not in practice create temperature excursions. This is how we will define exceedance from here on in this paper.

A number of projects, including CLNR, have shown that real-time OHL ratings do drop below ER P27 default values, although load may also have been low at the time. That is, we have shown that excursion values are non-zero. We need to face up to this risk, and make its treatment explicit within our planning standards, e.g. in the ongoing fundamental review of ER P2, and in updating the guidance notes to ESQCR.

7.1.2. Setting planning ratings

The stages of setting planning ratings are:

- Choose a model for the thermal response of the given asset
- Calculate default ratings for generic applications using generic default inputs, which is the approach of ER P15/17/27; and then
- Refine the ratings for critical applications by replacing default model inputs by site-specific data

As previously noted, if that bespoke rating is likely to be exceeded, we then have to move to active control or to reinforce.

The trials we have carried out in CLNR confirm that there is scope to improve the accuracy of static ratings by using parameters and load curves for the actual location. The type of monitoring we have used for RTTR can therefore be used offline to inform desktop studies of capacity for seasonal loads or weather related generation.

[16] Strictly, we have found some issues with the way that P27 values have been calculated, but we get to very similar results

[17] As previously discussed, we have avoided putting customers at risk during CLNR, so we have artificially reduced the parameters in the real-time thermal models to make assets operating well within rating in reality appear to the control system as if overloaded

7.1.2.1 Transformers

We have chosen to use the latest international standard model from IEC 60076-7 to consider static ratings. This is very similar to the older IEC 354 model used in the smart RTUs.

This model can be considered in two parts:

- A steady-state model of what temperature the transformer's components would reach under a given set of conditions
- A dynamic model of how the temperatures of those components move as those conditions evolve

The key parameters for that first model are:

- Load and no-load losses, which define the power required to be dissipated as heat
- The shape of the load curve
- The oil and winding exponents, which calibrate how Newton's law of cooling applies to the unit
- The temperature gradients within the unit, particularly the informed judgement on hot spot above average winding

Within the limits we have observed, ambient temperature is not critical.

The key parameter for the second model is the thermal time constant of the unit, driven by the mass of the key components.

For transformers, the rating we can apply changes according to the limiting factor chosen and upon the shape of the load curve.

Here, we're going to limit ratings from the hot spot temperature. Ageing is neither a meaningful nor helpful concept for distribution transformers. While the cellulose in the papers clearly degrades faster at higher temperatures, with that rate doubling for every 6K rise, this is all relative to an ill-defined baseline. Transformers aren't built with a guaranteed service life, so we cannot meaningfully say that doubling the ageing rate will halve the life, because we do not know for sure what that life would be. Experience shows that only very few distribution transformers show signs of significant cellulose degradation, as measured in Furan analysis of the oil.

This is confirmed by the approach of ENA-TS 35-2, continuous emergency rated transformers. This is the specification against which the majority of primary transformers are bought. The ratings in that specification are set explicitly for a 140°C hot spot: ageing has no place in that specification, because industry experts recognise that it has no value.

Experience of generator unit transformers, which are used very differently to distribution transformers, shows that running above nameplate for extended periods does lead to material cellulose degradation. Should we start to use distribution transformers more like generation transformers, we'd need to consider ageing as well as hot spot.

CLNR suggests that, for the load curves we have observed and for CMR (IEC 60076) rated units:

- 130°C hot spot gives an uplift of 118-128% over nameplate; and
- 140°C hot spot gives an uplift of 127-137% over nameplate[18]

These values are broadly consistent with the default 130% value in P15, and also suggest an uplift of 5-10% (7% on the specific case observed in CLNR) from bespoke analysis. As P15 presently refers only to transformers with primary-side voltages at 132kV or above, essentially those covered by ENA-TS 35-3, we need to extend the recommendation down at least to ENA-TS 35-2 (primary transformers at 66 or 33 kV) and preferably to ENA-TS 35-1 (distribution transformers).

CLNR also shows that, for the unusual load curve at Sidgate Lane, an uplift of over 50% over IEC 60076 nameplate was possible. This confirms the importance of the load curve on asset rating.

For bespoke analysis, a proper temperature rise test in accordance with IEC 60076-2 will reveal the key parameters of the unit. Given the thermal time constants involved, using half-hourly demand profiles is good enough.

7.1.2.2 Overhead lines

We have chosen to use the standard CIGRE model. The equipment we installed (described in more data later) measured conductor temperature, allowing us to verify that model. CLNR shows a strong correlation between predicted and observed temperatures.

For site-specific analysis, CLNR suggests that the key parameters, i.e. those to which the static cyclic planning rating is most sensitive, are:

- Wind speed
- The shape of the load curve, i.e. how well it correlates with wind speed
- Conductor DC resistance; and
- Height above sea-level

The CIGRE model ignores wind direction (yaw angle) when wind speed drops below 0.5m/s. It would simplify implementation to extend this to all wind speeds. CLNR modelling confirms that this approach has a negligible impact for the key sheltered sites.

Around 20% of ratings observed at the sheltered sites are lower than the presently implemented P27 static ratings. This is consistent with (amongst others):

- The SPEN project which found projected excursions averaging 8.7% on the trial network. This is composed of dual circuit towers, which we'd expect to be less sheltered than the wood pole line considered in CLNR
- Strategic Technology Programme (STP) Project S2126, which draws similar conclusions that the P27 ratings do not, in practice, give the stated probabilities of excursion under real-world conditions

However, once we take into account the thermal time constant of the conductor, which allows us to ignore short current excursions, and also correlate against the circuit load, we can find a rating with a high confidence of not being caught out that is consistent with present P27 ratings:

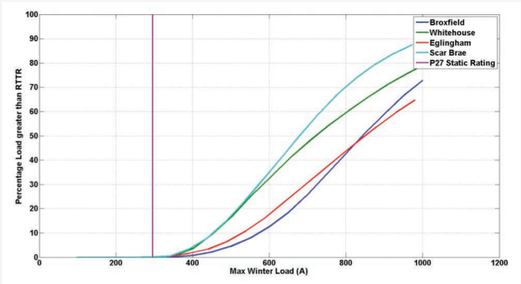


Figure 17: Percentage load exceeding observed RTTRs at the HV sites in the winter P27 period

For bespoke analysis, conductor DC resistance and height above sea level are static values which it is easy to obtain. Given the thermal time constants involved, it would be preferable to have five-minute values for wind speed and load. If only, for example, half-hour values are available, some de-rating will be required to allow for short load / temperature excursions.

CLNR results show only modest gains from bespoke ratings. The highest uplift available with zero material exceedance was 5% above P27 for winter peak loads.

7.1.2.3 Underground cables

We have applied the CRATER model developed by EATL, one of the project partners.

For site-specific analysis, CLNR suggests that the key parameters, i.e. those to which the static cyclic planning rating is most sensitive, are:

- The shape of the load curve, which can be approximated by the loss load factor
- Cable construction, i.e. the resistance and size of the conductor and how much insulation the heat has to get through
- Soil thermal resistivity, i.e. how quickly heat is carried away from the cable

We have found results broadly consistent with ER P17. The worst-case distribution ratings we calculated were 96% of P17 values (after applying the appropriate correction factors within that standard) for HV and 97% for LV.

The key learning outcome is that we need to apply the correction factors provided within that standard rather than just use the headline figures, as the ground conditions we have observed have been significantly worse than the default values:

- A soil temperature of 10°C remains appropriate for winter peaking demand
- For the LV cable, the default value for soil thermal resistivity of 0.9 K-m/W remains appropriate
- For the HV and EHV cables, a higher soil thermal resistivity of at least 1.5 K-m/W seems appropriate

For bespoke analysis, the static characteristics of the cable should be easy to obtain. The key local parameter is soil thermal resistivity, which should be measured on site: we could be able to unwind the 10% generic de-rating given. Given the thermal time constants involved, using half-hourly demand profiles is good enough.

7.1.3 RTTR as a trigger

The network solutions within CLNR are all about holistic area resolution of multiple constraints using multiple solutions. True RTTR is part of that approach.

[18] For 2014 measurements, for the Denwick primary transformers, for the 99th percentile (assuming that we fit a WTI and accept the risk of customer disconnection under worst case outage), our analysis gives bespoke static ratings of 125% of nominal at 130c and 133% of nominal at 140c; 100th percentile is 3% lower, at 122% and 130% respectively; for 2014 measurements, for the secondary transformers on the Denwick subsystem, for the 100th percentile (assuming we don't accept a risk of customer disconnection because of the lack of redundancy), our analysis gives bespoke static ratings of 118-128% of nominal at 130c and 127-137% of nominal at 140c

7.1.3.1 Transformer RTTR

Introduction

Transformer thermal capability is influenced to a degree by the temperature of the cooling air, varying by roughly 1% for each degree Kelvin. More important for actively-managed networks is the long thermal time constant of the unit, which allows loads well above nameplate to be carried for a while without causing a damaging temperature rise. This can be particularly helpful in the first few hours after a fault.

Method

In the absence of a commercial-off-the-shelf solution, we expanded the power of the smart RTU to include online calculation of transformer thermal performance. Using the standard IEC 354 model, which is very similar to the 60076-7 model, the RTU calculated internal temperatures from measured load and cooling air temperature.

The modular nature of the smart RTU allowed us to roll this out to both primary and secondary transformers.

Strictly, the solution deployed for CLNR is a dynamic rating rather than a real-time rating. Both solutions work out the steady-state thermal limit for a given asset using real-time data on ambient conditions. Dynamic ratings then require present demand and the thermal inertia of the asset to be considered, to calculate what demand the asset could carry for a defined period from the point of calculation.

Findings from CLNR

Benefits

As previously discussed, RTTR delivers the biggest benefits when true real-time and dynamic thermal ratings are integrated into a sophisticated area control scheme and in particular when deployed as an enabler to reducing the operating costs of DSM. We have proved that we can use transformer RTTR both:

- In a local control loop to drive co-located DSM (EES); and
- In a wider coordinated scheme, to drive both co-located DSM (EES) and also remote resources (DSR)

We have also demonstrated that it is sufficient to use load and cooling air temperature; and that it is most effective to measure that temperature adjacent to the transformer coolers.

Costs

We estimate the costs of doing this again, assuming a smart RTU, at £51,000.

Findings from other projects

Relevant projects

As of November 2014, four LCNF projects published on the OFGEM portal contained work relevant to thermal rating of transformers. Three of these (WPD's FALCON, SPEN's Flexible Networks for a Low Carbon Future and UKPN's Power Transformer Real Time Thermal Rating) are still in progress and have not published their findings. These projects will however produce considerable additional transformer thermal data which can be used to progress the design of transformer RTTR systems.

Most of these relate to off-line bespoke analysis rather than true real-time control.

Progress reports from SPEN Flexible Networks for a Low Carbon Future indicate that they are achieving increased transformer ratings by the application of RTTR, but the gains appear modest compared to previous projects. It is not yet known whether these gains are due to bespoke asset ratings (as in EATL Transformer Rating studies), time-limited capacity enhancements (as in ENA ER P15) or a combination of the two.

WPD FALCON project is undertaking significant validation work on its transformer models, including heat runs on operational transformers to show output accuracy. This work will be very interesting when it is completed and published, as it will have to contend with (and separate) both sources of rating uplift.

Outside the LCNF, Electricity North West has an ongoing IFI project (started in 2010) to investigate the dynamic rating of distribution transformers. This includes the installation of eight new transformers with internal temperature sensors, the development of thermodynamic models, and a large scale (100 transformers) program of non-intrusive thermal sensing on existing transformers. Because this is an IFI project and not completed, no outputs are currently available.

The sole relevant completed LCNF project is SPEN's Ashton Hayes Smart Village, which calculated thermal ratings for a single 100kVA pole-mounted distribution transformer. This is a small-scale project and produced limited outcomes because the transformer temperature could not be reliably measured. The recommended follow-up measurements of transformer frame and oil temperatures have not been undertaken.

Outcome summary

The only project for which outcomes are available is SPEN Ashton Hayes Smart Village. From the monitoring data available (ambient temperature and loading), modelling of the transformer ampacity and temperature was undertaken following IEEE Standard C57.91-2011 and BS EN 60076-1:2011 (this modelling therefore does not include the effects of wind cooling on the transformer). Based on the model it was predicted that the transformer was operating hotter in summer (when high ambient temperatures reduced cooling) than in winter (when low ambient temperatures very substantially increased the transformer ampacity). These results are based on only the load profile encountered (which has a morning peak much larger than the evening peak), and only a small number of days data was analysed. However, they indicate that it is not a foregone conclusion that transformers are most stressed during heavy winter load (as has largely been assumed to date). In some circumstances the capacity constraint on a transformer asset may be summer loading and temperatures, rather than winter load, which will need to be taken into account in future network design processes.

Practical issues

It still makes sense to put the transformer RTTR algorithm into a smart RTU, as the first practical use case will be a local control loop to call dedicated DSM. Such an approach is also straightforward to implement, with little disruption from the small wiring required.

We will provide back-up protection through a standard winding temperature indicator (WTI). To protect the transformer, we can set the trip level no higher than 140°C hot spot, so we will likely configure the RTTR algorithm (and the wider control loop) around a 130°C hot spot.

To optimise dynamic rating, we also need dynamic loading to do otherwise loads to a (flawed) approach of:

- Compare forward-looking rating to present load
- If running at 99% of capability, do nothing
- If load then rises before we can do something about it (e.g. by calling DSR on a 20-minute response time), we will exceed capability

We tried this approach on the CLNR smart RTU but failed, because of noisy analogues. It may be more effective to:

- Deploy real-time estimation of hot spot temperature (where the long thermal time constant of the transformer inherently smoothes out a noisy load); or
- Model dynamic elements off-line, to determine threshold for action at a pre-determined percentage of estimated temperature, i.e. respond to present rating and recent load history rather than trying to predict either one

7.1.3.2 Overhead Line RTTR

Introduction

As overhead lines have short time constants, ranging from approximately four minutes (Almond, i.e. 25mm^2 AAAC) to 17-minutes (Elm, i.e. 175mm^2 AAAC), the previous loading history has little effect, and cyclic uplift is minimal. Instead, the rating of these assets is dominated by external conditions, particularly wind speed.

Method

Following competitive tender, we deployed six GE FMCTech monitoring units, four at HV (20kV) and two at EHV (66kV). Half of each group were deployed on sites sheltered from the prevailing wind by trees etc. All these sites were on our rural Denwick test bed. The apparatus comprised:

- A conductor temperature sensor clamped directly onto the line
- A weather station on a nearby support
- A local control unit to provide a communications bridge; and
- A remote server to process and store information

Findings from CLNR

Benefits

As previously discussed, RTTR delivers no benefits in itself, but is an enabler to DSM. We have proved that we can use overhead line (OHL) RTTR in an area coordinated scheme, to drive remote DSM (EES).

Having used the comprehensive monitoring of the GE FMCTech device, we can now be confident that using wind speed alone, in a suitably calibrated algorithm, is sufficient. This has previously been discussed under planning ratings.

We have also found a reasonable correlation between observed wind speed at different sites, giving us confidence that we can measure wind speed in one location and use it to assess RTTR across an area of the network.

Costs

We estimate the costs of doing this again at £12,300 per site at HV and £16,600 per site at EHV.

> As previously discussed, RTTR delivers no benefits in itself, but is an enabler to DSM. We have proved that we can use OHL RTTR in an area coordinated scheme, to drive remote DSM (EES).

Findings from other projects

Relevant projects

Overhead Line RTTR has been the most active area of trials under the Low Carbon Network Fund. A total of five projects have been identified, using equipment from three different suppliers, as shown in table 7.

The GE Digital Energy system employed in the Customer-Led Network Revolution has also been used in the ongoing SPEN Flexible Networks for a Low Carbon Future project. This will provide similar data (including direct measurement validation) to the CLNR project, but on a dual-circuit 33kV network in Scotland.

The most substantial Overhead Line RTTR project to date has been the SPEN Implementation of Real Time Thermal Ratings project, on 132kV overhead lines in North Wales. This project employed a centralised architecture with Nortech RTUs measuring weather and load data and feeding into a Calculation Engine provided by GE as part of its PowerOn Fusion package.

The UKPN Flexible Plug and Play project, by contrast, uses a distributed architecture for RTTR on 33kV lines, with ampacity being determined by RTTR relays installed at three Grid / Primary substations, based on local weather station data and loading. The calculated ampacity is then fed into the (central) SCADA system to drive the Active Network Management aspects of the project.

WPD Low Carbon Hub project appears to be similar in approach to SPEN Implementation of Real Time Thermal Ratings, in that the OHL RTTR Calculation Engine is being implemented in GE PowerOn Fusion.

By contrast WPD FALCON is deploying a distributed architecture using Alstom RTUs providing the Calculation Engine function. Conductor temperatures and load currents are being measured using Tollgrade online sensors, making this one of the few projects where closed loop validation of modelling results will be at least partly possible.

Outcome summary

The only project with final outcomes available is SPEN Implementation of Real Time Thermal Ratings. The decision to perform RTTR as part of the SCADA system for this project enabled direct control room integration of RTTR outputs, but required real-time communication of all monitoring data to the central control facility. As with the CLNR project, this was largely carried out over GPRS, and difficulties were encountered with signal strength and reliability. RTUs at primary substations were directly connected to existing SCADA networks, which provided much better results.

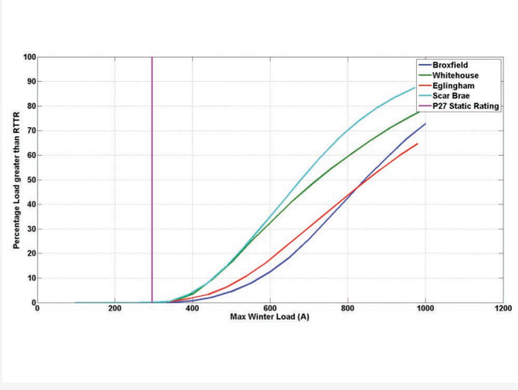


Figure 18: Correlation of observed wind speed between sites

Due to supply chain and outage constraints this project did not install any conductor temperature sensors, so the project operated entirely in an open-loop mode, with no feedback on actual line temperatures encountered. This means it is not possible to say what line temperatures actually occurred as a consequence of the RTTR operation.

A detailed line survey was carried out in order to provide topological data to feed in to the weather condition interpolation algorithm, used to derive per-span weather conditions from weather stations spaced 10km apart. No view was taken at this stage as to which spans were likely to be the limiting spans for the line, although individual span heights above ground were made available to the RTTR model.

Because the equipment was installed on the actively managed 132kV network with significant wind farm generation connected, it was possible to control the power flows and adjust network loading in response to the changing ratings calculated. Significant increases in wind farm energy output (10% to 44%) and average line rating (1.24 to 1.55 times summer rating) were achieved on the project network.

Practical issues

An holistic systems approach is required for the safe implementation of overhead line RTTR. All RTTR involves a paradigm shift, of deliberately running the network so that demand could exceed capability, and we introduce an active coordinated controller to stop that happening.

We must therefore coordinate feeder protection and the RTTR algorithm, so that we:

- Safeguard the general public, by providing protection against overload as well as fault, which requires a low setting
- Avoid nuisance tripping because the default setting is too low

This requires dynamic protection settings working in harmony with the RTTR algorithm.

As OHL RTTR is so dependent on wind speed, it is possible for any span to become critical for rating. The SPEN TSE has overcome this through a sophisticated algorithm, but it is not clear how this can be integrated with a protection system without introducing a common-mode failure risk that makes back-up protection pointless. This is not about the RTTR algorithm, which we can tune to any level of risk we like: it's about finding a setting for any back-up protection we choose to install.

A cruder, but more practical, solution is that adopted for UKPN's FPP. Here, they've placed a wind speed gauge on the roof of a primary substation. The data goes off to the area controller and into the feeder protection relay. That relay runs the same RTTR algorithm as the area controller to turn wind speed into a rating, and then uses that rating as an adaptive setting for the #49 thermal overload curve.

This approach relies on understanding the correlation between wind speed at the primary substation and at a remote, sheltered span. As discussed earlier in this paper, we have shown in CLNR that such a correlation exists specifically, that wind speed at a remote sheltered site is of the order of 30% of that at the primary.

The UKPN FPP approach also overcomes a key limitation observed with the CLNR OHL RTTR set-up, of highly unreliable communications. The system as a whole was available for less than 40% of the time. Putting the sensors at a primary substation, as for FPP, should overcome this.

Project	Lead DNO	Equipment	Completed?
Implementation of Real-Time Thermal Ratings	SP Energy Networks (SPEN)	Nortech (RTUs), GE PowerOn Fusion (Calculation Engine).	Yes
Flexible Networks for a Low Carbon Future	SP Energy Networks (SPEN)	GE (RTUs and Calculation Engine)	No
Flexible Plug and Play	UKPN	Alstom (RTUs), Lufft (Weather stations)	No
Low Carbon Hub (building on Skegness RPZ)	WPD	GE PowerOn Fusion (Calculation Engine)	No
FALCON	WPD	Tollgrade (online RTU), calculation engine unknown	No

Table 7: LCNF projects investigating the use of RTTR

7.1.3.3 Cable RTTR

Introduction

RTTR is a methodology to assess operational thermal rating of underground cables using real-time data on their installation environment conditions and operating loading rather than conservative assumptions. It has been postulated that RTTR could provide further information on thermal headroom; indicating whether areas are stressed (overheated) or in fact have more capacity than originally anticipated.

Operational temperature is a key indicator in RTTR. It can be monitored and measured continuously against equipment which has a Distributed Temperature Sensing (DTS) system, or has to be estimated based on installation condition information and loading data for those without a DTS system.

RTTR application for underground cables with DTS is categorised as self-contained RTTR scheme, RTTR for cables without DTS is termed as an environmental based RTTR scheme.

For a large proportion of existing underground distribution networks, a DTS system is unlikely to be available; an environmental RTTR application therefore has to be used to estimate cable operational temperature using cable thermal modelling software, based on real-time cable installation condition information and real-time loading. A trial project of environmental based RTTR for UG cables was carried out as a part of the CLNR project.

Method

We deployed:

- Temperature sensors for soil temperature and cable sheath temperature measurement
- Thermal resistivity sensors for soil resistivity measurements
- Ambient temperature sensors
- Pyranometers for solar irradiance measurements
- CTs and VTs

These were brought back over the Envoy / iHost chain used for the CLNR monitoring, then accessed by an off-site server running EATL's CRATER package.

Strictly, the solution deployed for CLNR is a dynamic rating rather than a real-time rating. Both solutions work out the steady-state thermal limit for a given asset using real-time data on ambient conditions. Dynamic ratings then require present demand and the thermal inertia of the asset to be considered, to calculate what demand the asset could carry for a defined period from the point of calculation.

Findings from CLNR

Benefits

We have found that the key parameters move so slowly that there is no practical benefit from true real-time or dynamic rating, no matter how sophisticated. Instead, offline bespoke analysis, as previously discussed under planning ratings, is the most effective way to release latent capability within underground cables.

Costs

Although we wouldn't roll this out, we estimate the costs of doing this again as £26,000 for an LV site and £55,000 for an HV/EHV site.

Findings from other projects

Relevant projects

Underground cable systems have long been known to have complex, long-term thermal behaviour, and are very expensive to upgrade once installed. There is a long history of the use of computational models to obtain cable ratings, given the difficulty of representative direct measurements. It is therefore surprising that elements of RTTR for underground cables appear in only two or three LCNF projects. This may be because:

- Off-line assessment is perceived to be well understood
- In practice, real-time or dynamic rating adds very little value

SPEN's Flexible Networks for a Low Carbon Future is employing real-time rating of 33kV circuits supplying primary substations. This project will go beyond the CLNR work in choosing sites which are already constrained, and deliberately operating the network there in N-1 configurations to produce maximum thermal loading. It is unclear whether this work includes underground cables (as originally submitted) or not, as reported progress is only on overhead lines and primary transformers.

WPD FALCON definitely has underground cable RTTR in its scope. The project is still under way, but reports work on the validation of the mathematical model used is being undertaken. There is no information on whether this is an environmental cable RTTR system or one based on a distributed temperature sensing system. For the SIM (Scenario Investment Model) offline tool being produced as part of this project, an off-line modelling tool for 11kV networks, based on the IEC cable ratings standards, has been produced and is being incorporated into the IPSA simulation package.

The SPEN Temperature Monitoring Wind Farm Cable Circuits project has installed a distributed temperature sensing system, but using fibre optic cable blown into a micro-duct located outside the (triplexed) cable sheaths. This unusual configuration places it somewhere between the environmental RTTR system employed in the CLNR and the traditional distributed temperature monitoring systems with the sensing fibre installed at the cable core, which is the limiting temperature. This project is still in progress but will produce some interesting data when it concludes.

Outside of the LCNF, Electricity North West has an ongoing IFI project (started 2014) to develop Cable Dynamic Ratings for LV distribution networks. We expect the findings of that work to validate further our CLNR output.

Outcome summary

No cable RTTR project outcomes from LCNF projects could be located, as the relevant projects are all still in progress.

Practical issues

As previously noted under findings, full RTTR for cables does not seem to be a practical solution.

7.2. Real power dispatch (thermal)

Introduction

Our network runs close to unity power factor, so power flows are dominated by the real power drawn by customers. Therefore, if we can dispatch real power in the opposite direction to the flow that's causing the problem, we can alleviate that problem. In CLNR, we have not looked at constrained connections.[19] Instead, we have looked at general solutions to general problems, and just tried to find a source of controllable real power in the right area of the network.

Work in CLNR, and in Northern Powergrid more generally, has focused on post-fault response for secured events within the planning standards. The very local networks within (e.g.) a village or housing estate have no alternative supply arrangements, but the wider networks feeding those areas do. This means that, when there is a fault on the wider network, we can often reconfigure the network to restore supplies to large areas before we finish any repairs. This also means that most of the time those wider networks are lightly loaded, and they work hard only when configured after a fault. In turn, this improves the commercial viability of DSR and GSR, as we'd ask customers to change what they're doing only infrequently.

These solutions apply equally to existing, unconstrained connections and new, potentially constrained connections. The electrical impact is the same, although the commercial arrangements may be very different.

Real power dispatch offers significant advantages to the conventional BAU solutions currently deployed to overcome network constraints. It can be contracted annually (allowing it to be turned off if not required in future years), it causes no impact on the environment) and provides a financial benefit to customers. For these reasons it is our policy that real power dispatch should always be the first solution considered and should be selected as long as it is 'at least' cost neutral to the next most economical solution. This approach provides a first step approach to the price to offer the market place although with further experience it would be expected to be able to drive this price lower. Following this approach we expect to identify the maximum number of real power dispatch opportunities within the region and provide benefits to the customer and the environment.

Method

Within CLNR, we have:

- Rolled out ToU tariffs to over *ca.* 600 domestic and *ca.* 40 SME customers
- Rolled out smart meter facilitated, tariff-driven response to:
  - 50 domestic customers' wet white goods
  - 17 domestic customers' heat pumps
- Procured real power response services from the following sources:
  - 80 domestic customers' wet white goods
  - 17 domestic customers' heat pumps
  - Two I&C customers' reduction in consumption
  - 14 I&C customers providing what would otherwise be stand-by generation
  - Distributor-owned EES, comprising of a grid scale battery and power conversion system:
    - *1 x 2,500 kVA/5,000 kWh at a primary substation*
    - *2 x 100 kVA/200 kWh at secondary substations*
    - *3 x 50 kVA/100 kWh at the remote ends of LV feeders*

ToU tariffs are a fit and forget option. We have called all of the other services from an RTTR / ANM / real power dispatch combination to address thermal overload. For voltage issues, we have also demonstrated that we can call EES real power both from:

a. The Siemens smart RTUs, responding to local measured voltage; and

b. The Siemens area controller, responding to the state estimator's view of voltages across the network

In CLNR, we have procured services only from existing customers with unconstrained connections. Within CLNR, we have not engaged customers requesting new or modified connections which are constrained from the start, as we consider this as BAU.

The trials have confirmed the final VEEEG models, bar immaterial quirks of the specific control schemes used in CLNR. There were no material issues with missing / noisy data over the trials. Although we have not tested in the field all the end-to-end combinations of monitoring / ANM / real power dispatch, we have tested all the components and interfaces. The modular nature of the Siemens solution means that we are satisfied that this degree of testing gives us enough confidence to be able to roll-out any combination.

As we have demonstrated in trials that we can resolve both over and under-voltage issues at the same site in the same day, across the extremes of that load curve, we're confident that these results can be extrapolated to other load curves.

Findings from CLNR

Benefits

We have confirmed that DSR, GSR and EES (real) all have the same effect[20], and that 'DSR' is often really GSR, as customers offer up generators otherwise used for stand-by power, rather than offering up reductions in underlying consumption. The CLNR-L145 Commercial Arrangements report confirms that distributors could reasonably tender for a generic 'real power services' contract, rather than specifying exactly how service providers source that response.

It's a statement of the obvious that DSM (whether DSR, GSR or EES) reduces load at roughly 1kW/kW on single radial systems and about 0.5kW/kW on ring or parallel systems. There is an additional benefit where the DSM is located much lower in the system than the constraint, as we can:

- Use the same solution for multiple series problems, e.g. offloading both secondary and primary transformers (if required); and
- Save on losses, which can approach 10% at peak

We have tested these concepts directly with: groups of domestic customers, both rural and urban; I&C customers; and typical market town mixed groups. We are therefore confident that these findings will apply to the majority of GB networks, although it is also clear from CLNR that the benefit of real power dispatch increases as the load curve gets peakier, i.e. this solution is most viable for trimming short, sharp spikes in demand.

Costs

It is assumed here that the real power response service cost argument is circular, as:

- When seeking day-in day-out response from customers as a whole, we'd set tariffs to reflect the avoided cost of other solutions
- We'd treat storage on the same basis as customer response, i.e. a contracted service rather than owning it ourselves; and
- When seeking an on-demand response to a particular constraint (or set of tiered constraints), we'd set a ceiling at the equivalent cost of other solutions when tendering. To ensure that customers as a whole benefit from the most efficient solution, we'd:
  - Pay as bid, so that customers don't over-pay; and
  - Apply the ceiling to average cost, so that if the aggregate cost of the DSR scheme is less than reinforcement, we'd go for DSR

The CLNR-L145 Commercial Arrangements report confirms that we were able to access DSM at rates consistent with the value of deferred reinforcement.

The commercial solutions report also confirms that the best route for EES is to be owned by somebody other than the distributor, because it allows freer access to additional revenue streams. This places EES on an even footing with DSR, as we'd simply contract for a real power dispatch service, regardless of how it's provided[21]. The DECC / Ofgem SGF WS6 has come down strongly against distributor-owned storage.

Findings from other projects

We're unaware of any other projects using real power dispatch for thermal control who have published their findings.

Practical issues

For most present load curves, the maximum potential reduction in thermal load is 20-30% relative for domestic customers, and about 10-15% relative for mixed customer groups. The practical limit is deemed to be the size of the evening peak relative to the day-time plateau: providing any form of real power dispatch for 3-4 hours at 60-70% utilisation is a much more viable proposition than across 10-12 hours at 80-90% utilisation.

Some kind of controller is always required here. As noted above, we have used both intelligent substations and area controllers, and both have worked well.

Reliability of the response is key. Some service offerings relate to running standby generation at remote, unmanned sites, and have proven particularly unreliable; others relate to stopping processes at manned sites. Overall, the commercial arrangements paper shows a reliability of 88%, subject to an availability of 83% after excluding some sites which we signed up but then immediately dropped out of the contracts.

This suggests an overall level of response around 73%, so we'd need to over-contract by around 40% to have a reasonable level of confidence.

We also need to understand the likely longevity of customer response, whether tariff-based or on-demand. If we have deferred investment for (say) five years on the assumption that we can continue to secure a response from some of our customers, and those customers then drop out of the scheme, we'd be faced with an immediate shortfall in network capacity.

As noted in the CLNR-L145 Commercial Arrangements report, domestic DSR is much harder to implement than ToU tariffs. The latter also offer greater benefits, as the day-in, day-out response can be used to address problems on local networks without alternative sources of supply within them.

We have found some specific issues on storage:

- For the smaller EES sites, ancillary load was so high that overall efficiency dropped from the 80% observed at the large (2,500kVA/5,000MWh) site down to 40%
- We have confirmed known issues over measuring state of charge, which is generally achieved by extrapolating from the observed voltage on the battery racks. At high charge (or discharge) rates, the internal resistance of the batteries introduces a voltage rise (or drop) which can under- (or over-) state stored energy by 5%

Where we apply real power response to an asset with a cyclic rating then, for planning purposes, we will need to recalculate the planning cyclic rating to reflect the new, flatter load curve.

7.3. Reactive power dispatch (thermal)

GB networks generally operate close to unity power factor, so reactive power has negligible impact on managing thermal constraints.

7.4. Combinations (thermal)

We have shown that we can combine EES and DSR for voltage control, minimising the energy required of both, reducing costs. This reads directly across to managing power flow.

[19] When connecting wind farms in particular, but any customer in general, network studies may show that the new customer would sometimes push voltages (at the points of supply to other customers in the area) outside statutory limits. To avoid problems, all distributors offer customers the option of a constrained connection, where their production or consumption (whichever causes the problem) can be limited as required

[20] There are subtle variations in response time and duration between customers; and EES can be used as a day-in, day-out response unlike DSR/GSR

[21] There is an argument that we should bias our selection by environmental impact, e.g. to avoid the use of stand-by diesel generation. However, it's not immediately clear how we could do this and meet our other obligations of fairness and efficiency

8. OVER-/UNDER-VOLTAGE

Our baseline is the 16% swing permitted by ESQCR, which needs to be shared between LV and HV networks. This is laid down not for safety reasons, but to facilitate the efficient operation of customers' equipment.

On present networks, we generally control voltage as delivered to customers served by the LV networks from devices connected to the HV network. Typically, the point of voltage control nearest to the end customer will be at a 33/11kV primary transformer. From there to the customer, the voltage is dictated by Ohm's law, i.e. the product of the current drawn by customers and the impedance of the network. To ensure that the voltage as delivered remains within statutory limits, we must make sure that the combined voltage swing on the HV and LV networks between the primary transformer and the customer does not exceed about 12% (i.e. the permitted 16% less an allowance for measurement error and control dead-bands).

Taking the HV and LV networks together allows us to consider each solution in terms of headroom released against the 16%, assuming that this will be used up by either HV or LV networks, or both, as required in each case. Implementing such an approach requires a tactical design tool which can assess both LV and HV networks holistically.

Each solution will be assessed in terms of costs and benefits: unless explicitly ruled out here, all solutions will be assumed to be viable; the only question is how they stack up against other options, which will be discussed in the merit order section.

8.1. Enhanced voltage control

Enhanced automatic voltage control (EAVC) is a term widely used in CLNR documents, so it's worth reviewing its use as we close out the programme. As will be shown, there is a lot to be gained from adding additional points of voltage control to cater for groups of customers whose behaviour becomes increasingly different one from other. In itself, this is not 'enhanced' control, it is adding additional control points.

In contrast, there are clear 'enhancements' to the control of OLTCs and similar devices (e.g. shunt reactive compensation), whether new or existing, which can release headroom without significant investment in hard assets.

Two specific issues are considered here:

a. Tighter dead-bands; and

b. Better use of the load-drop compensation (LDC) feature on most existing voltage control relays

8.1.1. Dead-bands

In Northern Powergrid at least, voltage control dead-bands are set to two tap steps. Reducing this to one-and-a-half tap steps can yield a modest increase in head room, of 0.625-1.0% depending on tap-changer design. DEI-CLNR-DC135 indicates that for a secondary transformer equipped with an on-load tap-changer this will increase the number of operations from around 130 operations / month to around 475 per month or around 5,700 per year; as Northern Powergrid policy is for major maintenance at nine years/50,000 taps, or around 5,600 taps/yr, this change will have a small 'adverse practical' impact.

8.1.2. Load-drop compensation

Load-drop compensation offers limited benefits in load dominated networks, where it is instead simple, effective and efficient to set the target voltage for the source transformer to deliver voltage at the upper statutory limit to close-in customers, and then let increasing customer demand drag delivered voltage down to the lower statutory limit to far-out customers under maximum load and credible worst case outage. In this scenario, there is no scope to raise the source voltage to offset load drop, because we'd exceed the upper statutory limit for close-in customers.

However, as increasing numbers of our customers produce energy, then lowering the source voltage offsets the voltage rise this generation causes, creating headroom for this generation. This approach recognises that the design limit condition of maximum load and credible worst case outage happens only rarely, so we don't always get large voltage drops between source and far-out customers. This means that we can afford to drop the source voltage at times of low load and still deliver voltage above the lower statutory limit.

There is a particular sweet spot for solar PV. Most customers take little power during sunny summer afternoons, so this is often when voltage drop along the network is lowest. This creates the greatest scope to reduce source voltage, and by happy coincidence allows us to create voltage headroom when most needed for solar PV.

Similarly, the early-morning export likely from micro-CHP occurs when the network is lightly loaded, so we can again reduce target voltages.

This broad concept has been well proven for the GenAVC and ACTIVI solutions.

Here, we propose a journey of:

- Reduce static settings by 1% to accommodate PV, which is present Northern Powergrid practice
- Apply default dynamic settings, using load-drop compensation, to give a variable voltage reduction of up to 3% dependant on transformer load
- Apply bespoke settings to relay dead-band and to line-drop compensation, including or excluding key feeders as appropriate
- Move to full coordinated control

Some commentators have suggested seasonal settings, but the approach outlined immediately above is more powerful, more flexible, and at least as easy to implement.

8.2. Spur on-load tap-changer (OLTC)

Introduction

LV networks in densely populated areas and HV spurs in sparsely populated areas share many characteristics. Each serves up to 1MW of demand, connected to the main line at a single point (at least under present design philosophy).

As we move voltage control closer to the point of delivery where it matters most, there is an obvious opportunity to create a point of control at the spur point, whether it be a regulator on an HV spur or an OLTC on the secondary transformer.

Each will tune out upstream voltage fluctuation, permitting full statutory range to be allocated to the local network, and also permitting wider swings on the upstream network: adding load-drop compensation (LDC) gives further benefits.

Method

In CLNR, secondary transformers with on-load tap changing capability were installed at three different locations across our distribution networks on rural, urban and a residential estate dense with PV generation.

Trials on these three installations over twelve months show that the technology works, it is reliable, controllable and flexible to support a range of both load and generation growth. During trialling we artificially put the units under enough stress to give meaningful results; and have had no material data issues or adverse operational events.

The trials have confirmed the final VEEEG models, bar immaterial quirks of the specific control schemes used in CLNR. As we have demonstrated in trials that we can resolve both over and under-voltage issues at the same site in the same day, across the extremes of that load curve, we're confident that these results can be extrapolated to other load curves.

Findings from CLNR

Benefits

The highlights from the project and the analysis performed on the data from the trials concluded that:

- HV/LV Transformer with OLTC can provide an extra 8.7% voltage headroom and 7.4% voltage legroom and can allow additional ASHP, EV and PV connection under Autonomous control
- HV Regulators can provide 9.8% extra voltage legroom but, in this trialled case, no extra headroom because the selected regulator can only boost voltages. HV regulators in conjunction with the GUS can increase allowable ASHP and EV connections significantly. However, the allowable PV connections cannot be increased, as the HV voltage regulator in the CLNR project can only boost the voltage. If extra tap positions are added to reduce the voltage at the secondary side, the allowable PV connections could also be increased

As we expect customers to install more generation, we need buck / boost facilities on these spur OLTCs. This yields voltage headroom and legroom broadly equivalent to the tapping range, each expressed as a percentage of nominal voltage. Enhancing the control through load-drop compensation can increase headroom for DG typically by 3%, and more may be available after bespoke studies. The greatest benefit comes from coordinated control of set-points through online optimisation in an area controller, which will be discussed in more detail later in this document.

Costs

We estimate the costs of rolling out OLTC to secondary substations as £96,000/site. We didn't install new HV regulators in CLNR.

Findings from other projects

ENW – voltage management on low voltage busbars

- This project has successfully demonstrated that distribution transformers with OLTC can effectively regulate voltage to yield a material increase in network capacity
- It has been shown that increasing the number of distributed generation installed on the network will also limit the effectiveness of the transformer with on load tap-changer
- The project has demonstrated that a coordinated approach to voltage control on the LV network may provide a more effective means of voltage management than the use of locally controlled devices but that both approaches offer benefits

Practical issues

It has already been shown that applying tighter dead-bands can, unsurprisingly, increase the number of tap operations significantly. It's also likely that applying LDC will increase the number of tap operations, because the bias applied from the load current will make the observed voltage more volatile. There may be a trade-off here, of foregoing the modest benefit of tighter dead-bands in favour of the greater benefit of LDC.

Applying load-drop compensation to reduce busbar voltage to accommodate DG creates a risk of running out of taps. The obvious solution is to reduce the upstream voltage, perhaps by applying load-drop compensation there as well.

It's good practice to keep OLTC controls away from the device itself, to reduce risks to staff when applying local manual control. This can be a challenge for regulators. For the secondary substations, the CLNR installations simply installed a standard high-security outside meter cabinet in the substation wall to house the controls, allowing operation from outside the transformer chamber.

[16] Strictly, we have found some issues with the way that P27 values have been calculated, but we get to very similar results

[17] As previously discussed, we have avoided putting customers at risk during CLNR, so we have artificially reduced the parameters in the real-time thermal models to make assets operating well within rating in reality appear to the control system as if overloaded

8.3. Shunt reactive compensation (voltage)

Introduction

Customers' equipment generally draws 'few' VArs but as demand increases, the network itself generally draws more VArs. It is possible to supply those VArs from shunt compensation closer to the customers, reducing the current drawn and therefore the voltage drop.

This is particularly effective down as far as the distribution substation bar, because voltage drop is dominated by that element of current in phase with the network impedance, and that part of the network is largely inductive. LV networks have more resistance, and so respond less well to reactive compensation and better to simply reducing the real power flow.

It is also possible to over-compensate, forcing a voltage rise through that network impedance.

It is assumed here that capacitor banks, inverters (e.g. those on the EES units), and GSR (e.g. Grid Code compliant PV mode control) all have the same benefit. They're just different means to the same end. The base case here is, like the generator PV mode, responding to local voltage.

Capacitors have advantages and disadvantages compared to regulators:

- Capacitors move the voltage at their connected busbar, so they manage volts both upstream and downstream;
- When over-compensating to reach their target voltage, capacitors can drive VArs back up through the primary transformers, as we have often seen on the CLNR test-bed networks. While all customers behave the same, so all voltage control devices are moving in similar directions, this is not an issue. However, as customer behavior become more diverse, creating excess voltage rise in another part of the network could become a problem

Method

In CLNR, we have;

- Modified an existing mechanically-switched capacitor bank (14 MVAr in one MVAr steps) at Hedgeley Moor Capacitor Switch House, upgrading the communication links and controls for compatibility with the Siemens CLNR ANM scheme
- Integrated the reactive capability of the inverters at the small-and medium-sized EES installations

Trials on these three installations over 12 months show that the technology works, it is reliable, and controllable. During trialling we artificially put the units under enough stress to give meaningful results; and have had no material data issues or adverse operational events.

The trials have confirmed the final VEEEG models, bar immaterial quirks of the specific control schemes used in CLNR.

Findings from CLNR

Benefits

VEEEG shows voltage sensitivity factors (i.e. the rate at which the voltage changes when we alter power flows) of the order of:

- 0.02%/kVAr at LV feeder end
- 0.01%V/kVAr at substation LV busbar on rural networks, much less on more compact urban networks
- 0.002%/kVAr, i.e. 2%/MVAr on the HV network

For practical unit sizes, based on the CLNR EES units, this suggests headroom / legroom gains of:

- 50kVAr at LV feeder end gives ±1%
- 100kVAr at substation LV busbar also gives ±1%; and
- 2.5MVAr on the HV network gives ±5%

Compensation fitted to one LVN will affect other LVNs in the area, as part of the effect is reducing voltage drop on the local HV. The relevant sensitivity factors from CLNR are those for the HV network, so a 100kVAr unit makes a 0.2% impact: this may not be much in itself, but could be powerful in combination.

Costs

We estimate the costs for a full EES if we did it again to be; £4.5 million for 2,500kVA; £490,000 for 100kVA; and £410,000 for 50kVA. Assuming these costs halve for reactive power support only, this gives around £2 million for 2,500kVAr and around £250,000 for 100 kVAr.

Findings from other projects

WPD – low carbon hub

- The DStatcom performance exceeded the estimated modelled performance, boosting voltage by up to 3%, dropping voltage by up to 5% under steady state conditions
- The device is designed with an 800V DC busbar and 480V AC connection connected to a step up transformer, connected at 33kV. At full output the LV current exceeds 1000A per inverter stack requiring significant forced cooling. The forced cooling leads to high noise outputs when operating at full output

Electricity North West – voltage management on low voltage busbars

- This project has successfully demonstrated that capacitors can effectively regulate voltage to yield a material increase in network capacity
- The project has shown that more than one technology may be required to manage the voltages on LV feeders associated with a distribution substation. Feeders which contain more generation than demand may require a different control approach than those that are without generation. The issue becomes more complicated when one substation contains some feeders with significant generation and others with significant new non-diverse low carbon loads such as electric vehicles and heat pumps. In these cases a capacitor could be installed to control the individual demand biased feeders whilst a transformer with an on-load tap-changer manages the rest of the substation which is generation biased
- The project has trialled several capacitor banks, the units are all installed around midpoint of the feeder to offset the load reactive power reducing the amount that needs to be supplied from the substation resulting in a lower volt drop
- Voltage control using capacitor banks can be less effective in the LV network compared to the HV network, as the feeders are more resistive. For more resistive feeders, the study shows that it reduces the voltage boost. The size of the capacitor which can be installed is limited depending on network conditions
- It is predicted that the number of electric cars could be significant in future networks. The charge cycle for each car would last several hours, and customers are more likely to charge them in the evening, causing the voltage drop during peak time to be even more significant. Therefore, the network may need to be further optimised and energy storage support could be an option, utilising the charging stations as well as energy storage installed along the feeders

WPD – voltage control system demonstration

- The integration of the D-SVC with DNO's systems was more complex than envisioned. The D-SVC was originally designed to be almost entirely stand-alone. In addition to this, the absolute effect of the D-SVC on the HV voltage was less than expected. It was thought this was predominantly due to the use of a standard transformer and the output of the D-SVC not being optimal for the size of the wind farm. The D-SVC did demonstrate a good ability to smooth the voltage profile. It was possible to assess the wider impact of reactive power on the system too

Practical issues

The use of reactive power compensation (and, to a lesser degree, real power compensation) affects the upstream network, and therefore affects voltages across a wider area of network than an OLTC connected at the same point. Where customers behave in a similar manner to each other, this is a beneficial bonus; where customers behave differently to each other, this can create a challenge. Area control systems (qv), by coordinating set-points, can mitigate this effect.

The points previously discussed on EES also apply here.

[16] Strictly, we have found some issues with the way that P27 values have been calculated, but we get to very similar results

[17] As previously discussed, we have avoided putting customers at risk during CLNR, so we have artificially reduced the parameters in the real-time thermal models to make assets operating well within rating in reality appear to the control system as if overloaded

8.4. Real power dispatch (voltage)

Introduction

Ohm's law dictates that a change in voltage is the product of the current and the impedance. Therefore:

a. The more power that customers consume, the greater the voltage drop; and

b. The more power that customer produce, the greater the voltage rise

Therefore, if we can dispatch real power in the opposite direction to the flow that's causing the problem, we can alleviate that problem.

It can be seen that this method is very similar to that for real power dispatch for power flow issues, and the same arguments apply to both.

Method

We have applied the same method for real power dispatch for voltage issues as for power flow issues, which are described earlier in this document. Reflecting the flexible, modular nature of the CLNR control scheme, we have used the same controllers for voltage as for power flow: the configuration of those controllers, both local and area, provides for voltage limits to be set as well as power flow limits.

We have also exercised the optimisation engine of the area controller, by giving it a target of reducing real power import. This led the controller to run the system at as low a voltage as consistent with statutory limits, reflecting the (limited) dependency of load on supply voltage.

The trials have confirmed the final VEEEG models, bar immaterial quirks of the specific control schemes used in CLNR. There were no material issues with missing/noisy data over the trials. Although we have not tested in the field all the end-to-end combinations of monitoring/ANM/real power dispatch, we have tested all the components and interfaces. The modular nature of the Siemens solution means that we are satisfied that this degree of testing gives us enough confidence to be able to roll-out any combination.

As we have demonstrated in trials that we can resolve both over and under-voltage issues at the same site in the same day, across the extremes of that load curve, we're confident that these results can be extrapolated to other load curves.

Findings from CLNR

Benefits

We have found voltage sensitivity factors of 0.08-0.16V/kW for the units at the remote end of LV feeders, where the impact is greater because those networks are more resistive than at high voltages. To illustrate that point, the sensitivity factors at the LV busbars of the associated secondary substations falls to 0.01V/kW or less. Applying the sensitivity factors for the remote end of LV feeders to a practical unit size of 50kVA implies headroom/legroom of 4-8V, or 1-2%.

We have tested these concepts directly with: groups of domestic customers, both rural and urban; I&C customers; and typical market town mixed groups. We are therefore confident that these findings will apply to the majority of GB networks, although it is also clear from CLNR that the benefit of real power dispatch increases as the load curve gets peakier, i.e. this solution is most viable for trimming short, sharp spikes in demand.

Costs

It is assumed here that the real power response service cost argument is circular, as:

- When seeking day-in-day-out response from customers as a whole, we'd set tariffs to reflect the avoided cost of other solutions
- We'd treat storage on the same basis as customer response, i.e. a contracted service rather than owning it ourselves; and
- When seeking an on-demand response to a particular constraint (or set of tiered constraints), we'd set a ceiling at the equivalent cost of other solutions when tendering. To ensure that customers as a whole benefit from the most efficient solution, we'd:
  - » Pay as bid, so that customers don't over-pay; and
  - » Apply the ceiling to average cost, so that if the aggregate cost of the DSR scheme is less than reinforcement, we'd go for DSR

The CLNR-L145 Commercial Arrangements report confirms that we were able to access DSM at rates consistent with the value of deferred reinforcement.

The commercial solutions report also confirms that the best route for EES is to be owned by somebody other than the distributor, because having fewer regulatory concerns allows freer access to additional revenue streams. The DECC / Ofgem SGF WS6 has come down strongly against distributor-owned storage. This places EES on an even footing with DSR, as we'd simply contract for a real power dispatch service, regardless of how it's provided[22].

Findings from other projects

We're unaware of any other projects using real power dispatch for voltage control who have published their findings.

Practical issues

For most present load curves, the maximum potential reduction in voltage drop is 20-30% relative for domestic customers, and about 10-15% relative for mixed customer groups. The practical limit is deemed to be the size of the evening peak relative to the day-time plateau: providing any form of real power dispatch for 3-4 hours at 60-70% utilisation is a much more viable proposition than across 10-12 hours at 80-90% utilisation.

Otherwise, the practical impacts of real power dispatch for voltage issues are the same as previously described for power flow issues.

8.5. Combinations (voltage)

We have shown that the use of EES and DSR in collaboration offers synergistic benefits beyond the use of a single technique:

- Results from the trials indicate that in some cases DSR response could be substantially slower than EES (up to 30-minutes). Therefore, for short duration voltage excursions, due to the intermittency of renewables based generation and new LCT based load, the fast response of the EES coupled with DSR could reduce the number of calls and improve the response of the collaborative voltage control system
- The energy capacity of the EES required in a collaborative voltage control system is reduced because the DSR system can remove or reduce the need for storage intervention. Given that EES technology is currently expensive and the cost of DSR is lower than the cost of EES, this is a valuable contribution

As customers' behaviour becomes more diverse, the challenge for voltage control becomes one of compromising between different voltage profiles along different feeders serving differing groups of customers. Dividing the customer group, e.g. by establishing spur OLTC, creates benefits both upstream and downstream:

- The full permissible voltage swing is available to the new sub-group; and
- The degree of compromise required of the upstream control point is reduced, because this sub-group now takes care of itself

[22] There is an argument that we should bias our selection by environmental impact, e.g. to avoid the use of stand-by diesel generation. However, it's not immediately clear how we could do this and meet our other obligations of fairness and efficiency

9. POWER QUALITY

> Even with smarter solutions, DNOs will still need to lay some new LV cable to cater for the increased power flow from clusters of LCTs, with the positive side effect of reducing impedance: this reduces any remaining risk of power quality issues.

The CLNR power quality report[23] identifies no power quality issues identified during the trials, even within clusters of similar customers, bar one rogue heat pump installation.

The report does note that heat pump manufacturers are treating the main unit and the auxiliary heater as separate units, and therefore subject to separate verification under EMC standards, which could make power quality worse than if the installation were controlled as a whole. As previously noted in this report, it seems unlikely that we will see frequent operation of the auxiliary heaters, so this may not be a major issue.

Even with smarter solutions, DNOs will still need to lay some new LV cable to cater for the increased power flow from clusters of low carbon technologies, with the positive side effect of reducing impedance: this reduces any remaining risk of power quality issues.

[23] CLNR-L146: CLNR Power Quality Assessment Impact of Low Carbon Technologies

10. COORDINATED CONTROL

We have achieved what we set out to do. The key aim of CLNR was to combine customer facing and network facing work: for the latter, our key aim was a control scheme which integrated non-network solutions like DSR and EES with both conventional network solutions like existing OLTC and novel network solutions like RTTR.

The CLNR Siemens area controller shows a level of sophistication unique within GB. This is not just about how it works, i.e. the powerful combination of a state estimator and online optimisation routine, but about what it does.

Other control schemes deployed on GB networks dispatch only real power, and resolve either power flow or voltage but not both. This controller can dispatch real and reactive power, from dissimilar sources, and resolve both power flow and voltage at the same time.

Using online optimisation also makes it easy to add new resources. We need only a simple model change to reflect the new asset, taking only a few hours, and then the optimisation engine will work out new set-points. This contrasts with rule-based systems, which would require off-line modelling to work out the new rules.

The open question is whether the benefits of such sophistication merit the cost. It took us a few man-years to set up the initial models, although they've required little maintenance since: as for any other sophisticated IS system, including our own core SCADA, there is an ongoing operational overhead just to keep it running smoothly.

With the homogenous customer mix typical of present networks, typified by the CLNR test beds, we have shown that well-calibrated load-drop compensation can deliver as much benefit as coordinated control.

CLNR has confirmed that voltage constraints emerge because the setting on any single device has to be a compromise for all the customers it serves: clever control schemes have only a limited ability to find a better setting, and come into their own when there are multiple resources whose settings can be coordinated.

A more challenging example is a network where multiple generators contribute to a voltage constraint. The CLNR Siemens area controller can control the source OLTC, then reactive power, and finally real power to optimise that network and maximise generation output within voltage limits. Alternatively, we could use simple local controls on both the source OLTC (where we drop the target voltage as the load falls away) and on the reactive power import of each generator (where we increase reactive import as the voltage rises), with a last ditch rule-based coordinated control of real power export.

This simpler solution begins to struggle if there is so much generation that we can not measure the underlying load from the source.

> "A more challenging example is a network where multiple generators contribute to a voltage constraint. The CLNR Siemens area controller can control the source OLTC, then reactive power, and finally real power to optimise that network and maximise generation output within voltage limits.

Whatever solution we use, we will need to monitor most of that generation to work out what's going on, with the first stage being to give the control engineer visibility of the network. We'd likely show on the main SCADA diagram an aggregate generation output figure (MVA, or MW/MVAr) next to the primary transformer throughput figure.

One intermediate option, rather than use full-blown state estimation, is then to add these two analogues together more accurately to gauge the load on the network. We could then use that figure to control the primary OLTC set-point, using a script on core SCADA, similar to the dynamic voltage control algorithm used by WPD in the Lincolnshire Low Carbon Hub project.

If we also had a power flow constraint, as well as voltage issues, the rule-based solutions presently available cannot use the same resource to resolve both constraints at the same time. To solve this arbitration problem, which has defeated other projects like Aura-NMS, we would need to upgrade to an optimisation engine.

We have also solved some practical implementation issues:

- We now know how to make the area controller look like an RTU, to provide alarms and analogues into core SCADA. We propose to give the control engineer visibility not just of what something's doing, but what it's been asked to do, e.g:
  - Measured voltage and voltage set-point for OLTC
  - Measured MW/MVAr and MW/MVAr set-points for EES or controlled distributed generation

This also allows us to use existing archiving functions to store this key information and make it available across the business.

- We understand our project is the only one which is looking right down onto the 400V network to derive set-points for assets at 66,000V. We're running a state estimator on a 10-minute cycle for two main models, one with 1200 busbars and the other with 2000. Again, we understand our project is the only one to operate at this level of complexity. To understand these networks, particularly the HV (6-20kV) element, we need to know the status of hundreds of switches. The efficient and economic means is to harvest this information from the core SCADA system, and we have created that link: we don't believe any other project gathers data from core SCADA

11. MONITORING

11.1. Introduction

Monitoring provides a network operator with visibility that the network is performing within its capability and is able to operate within legal and regulatory limits (e.g. Statutory Supply Voltage limits). Network visibility that is required for network control is different (more onerous) in terms of accuracy, periodicity and data latency from the network visibility that is required for network design, which is different again from that required for network planning.

In the CLNR project monitoring was deployed to understand the impact of LCTs on network feeders at LV and HV. Monitoring was also deployed to understand the behaviour and impact of the smart solutions - EAVC, RTTR, EES and DSR – which were investigated in the CLNR project. The monitoring data was used for analysis of the network trials and the learning from the project has implications for control, design and planning of networks.

Using the learning from the project, a recommended cost-effective BAU monitoring strategy has been produced, which would provide data for the purposes of planning, design and control in a cost effective manner. Data of lower resolution and higher latency, suitable for planning purposes, when suitably augmented by higher resolution, lower latency data, can be re-used for network design and control, reducing the overall cost of providing a full data set for network purposes. Draft data specifications for monitoring equipment for these purposes have been produced. This section summarises the CLNR monitoring report[24].

11.2. Method

The type of monitoring carried out in the CLNR project was dependent on the monitoring location. There were eight generic monitoring locations, denoted M1 to M8 as shown in Figure 19 and Table 8.

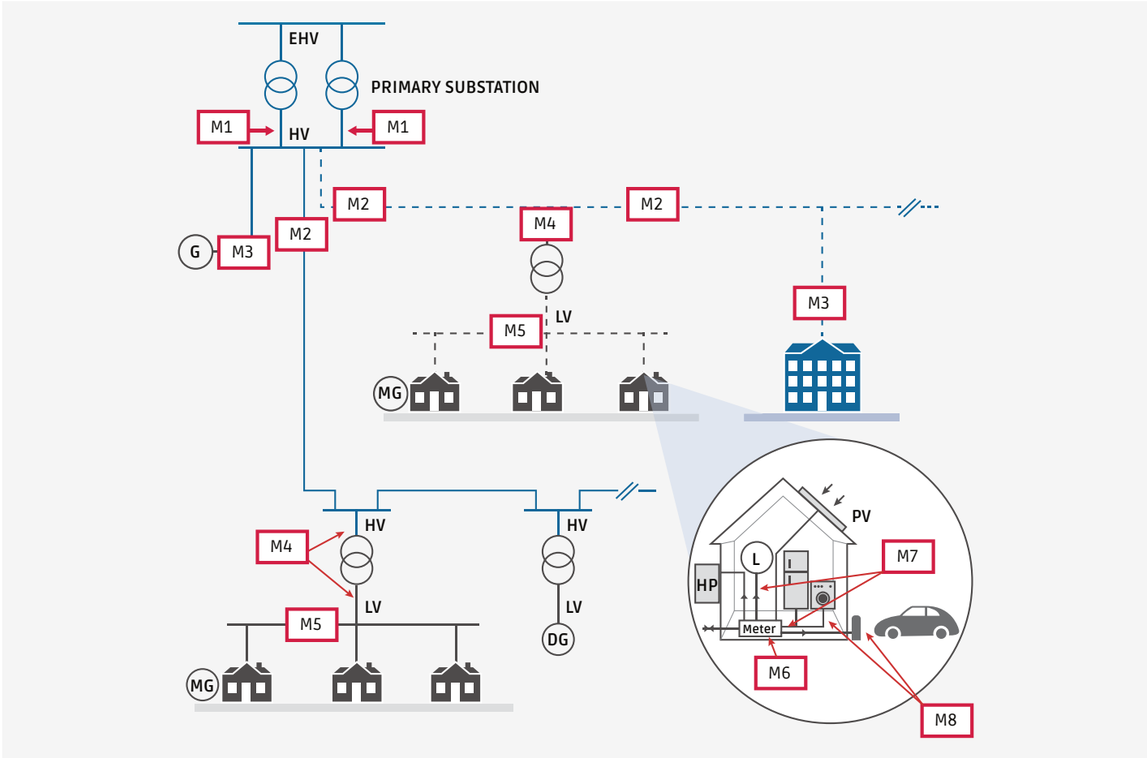


Figure 19: Generic monitoring locations

[24] CLNR-L232 Enhanced Network Monitoring

Monitoring Type	Description of Location and Functionality
M1	Primary transformer output 3-phase monitoring of voltage and current, real reactive and apparent power
M2	HV feeder monitoring either at source or some additional secondary monitoring point along the feeder 3-phase monitoring of voltage current, real, reactive and apparent power
M3	HV I&C customers typically connected to metering VTs with CT measurement of metering CT secondary current, 3-phase monitoring of voltage, current, real reactive and apparent power
M4	Secondary Distribution transformer monitoring connected to HV or LV as most convenient, typically expected to be LV connected, 3-phase monitoring of voltage current real reactive and apparent power current and voltage harmonic distortion flicker and unbalance
M5	LV feeder monitoring at substation or additionally at some other points on the feeder 3-phase monitoring of voltage current real reactive and apparent power current and voltage harmonic distortion, flicker and unbalance
M6	LV customer's cut-out provides information about aggregate or net site load, typically provided by use of a smart meter but can be a separate monitor for non BG customers
M7	LV ring main or other dedicated circuit at or near consumer unit to provide disaggregated load monitoring of a larger load or group of loads
M8	LV appliance or equipment provides disaggregation of individual appliances or equipment

Table 8: Monitoring type and descriptions

11.3. Findings from CLNR

Disparate systems have been successfully integrated to provide an overall monitoring solution including pre-existing SCADA, a separate control and data communication system using the GUS controller and associated remote distributed controllers plus data acquisition using iHost and associated RTUs.

The learning from the project has enabled the original monitoring specifications to be refined. The learning from the monitoring activities in CLNR has been distilled into a recommended monitoring strategy for BAU. More details and the rationale for this strategy are given in section 7 of the report and are summarised below.

Data, information and knowledge

The CLNR project has looked primarily at voltage and power flow, with a limited analysis of power quality.

Monitoring provides data on network status, at the places and times on the network that measurements have been made. However, this data has no intrinsic value without further processing. What is actually required is knowledge of network status, now and in the future (what is meant by future will be discussed further below).

For power flow, DNOs need to know what's about to be overloaded. For voltage, DNOs need to know where, what is delivered to customers is about to go outside limits. The approach to both is so similar that:

- For design purposes, generally the same load flow run of the same network model with the same data is used to assess both power flow and voltage sufficiency
- For control purposes in the CLNR project, using a real-time state estimation and optimisation controller, the same run of the same model with the same data was used to assess both power flow and voltage simultaneously

Power flow (demand) and voltage can be measured at various places at various times. This is data.

Modelling activities can provide Information:

- Measured values of power flow and voltage can be used in a load flow model of the network to produce time-resolved profiles of power flow (demand profiles) and time-resolved voltage profiles at many points on the network, not just those that have been monitored
- These calculated demand profiles and voltage profiles can be used to produce generally applicable profiles for given conditions, for example for winter and summer periods, weekday, weekend day etc. This is information (there has been data processing, taken averages, chosen representative periods, etc.)
- The calculated demand profile at various points on the network defines the power that the circuits are, and will be, required to carry at various defined times, hence the required capacity at those points

We need additional information in order to create the required knowledge e.g:

- The statutory voltage limits for supply of power to customers
- Capacity of the circuit to carry power
- Longer-term change in demand (for planning purposes this could be derived from customer data, or network power flow data processed in a different way)
- Possible network topology changes, which might be required to accommodate circuit outages due to maintenance or faults (for control purposes...probably defined from scenario planning)
- Other information, depending on the knowledge that is required

In the UK, engineering recommendations P15, P17 and P27 are generally used to define the capacity of electricity distribution network assets to carry power. In this report we use the term 'static ratings' for these quantities. Other aspects of the CLNR project have assessed the suitability of static ratings for Overhead Lines, Cables and Transformers and have explored alternative methods to determine actual circuit capacity.

By comparing the demand profiles with the capacity of circuits to carry power, we can know what's about to be overloaded. Also by comparing the voltage profile with the statutory voltage limits we can know what's about to produce a voltage excursion.

These are fundamental principles that apply to control, design and planning of a distribution network. These fundamental principles can also be expanded to include other things that DNOs need to know which are outside of the scope of CLNR, e.g. Fault Level.

There are similarities in the approach which can be used by control, design and planning functions to create knowledge of potential overloads and voltage excursions, albeit that the functions are necessarily interested in the same knowledge over very different timescales.

Depending upon the value of the risk of overload or voltage excursion (i.e. the probability of overload or voltage excursion multiplied by its consequence in terms of safety, regulatory penalties, cost of remediation etc.), the following approaches may be adopted:

- In simple, well understood situations, use deterministic limits and provide policy guidance (this is the default position in many cases today)
- Where the situation is too complex for management using limits, or management using limits would result in an unacceptable cost, then mathematically reduce the problem, describe using simple rules and provide guidance
- Where the situation is (or is believed to be) too complex for management using rules, or management using rules would result in an unacceptable cost, then use load flow modelling

Note that irrespective of which of these approaches is adopted, the underlying philosophy is the same. i.e. generate information from data. Combine information to produce knowledge and act on that knowledge. Clearly, cost is an important factor when deciding what and how to measure or model. It is uneconomic to implement low latency monitoring of everything everywhere.

Note that in this report, a distinction is drawn between Measuring (i.e. using a sensor to produce a value that can be read or stored locally) and Monitoring (i.e. communicating a measured value at regular intervals to a central location).

Application of this approach leads to the following recommended monitoring strategy for BAU.

11.4. Recommended monitoring strategy

- Endeavour to identify the lowest cost route to acquiring knowledge, which is needed to ensure that a distribution network can fulfil its purpose whilst operating within its physical, regulatory and legal constraints
- Relatively low time resolution data with high latency for planning purposes can be augmented by higher time resolution data on specific circuits for design purposes. Higher time resolution and low latency data is required for control purposes. For example, the characteristic thermal time constant of overhead line conductors typically used for distribution networks range from approximately four minutes (Almond) to 17-minutes (Elm). A control system requires measurements at intervals which are of the order of the characteristic time constant, or less, if it is being used to avoid thermal overload of the conductor
- Where it is more cost effective, modelling can be used to produce information from monitoring data in preference to installing more monitoring equipment. For example, half-hourly demand profiles are sufficient for planning purposes. These demand profiles can be used in a suitable load flow model of the network to calculate voltage profiles. The voltage profiles can be used to identify circuits with potential voltage issues and produce alerts. These circuits can then be studied in more detail, which might require additional monitoring of a broader range of quantities with higher time resolution. 'Modelled' alerts could be compared with real alerts from monitors (e.g. smart meters) as a means of verifying / validating the model or to identify further model refinement

Hence:

- Where you can afford to measure something directly and both a) need to and b) can afford to monitor the measurement value with low latency, monitor continuously
- Supplement measurements with outputs from a representative model which takes measurement values as inputs, providing that this is more cost effective than making more measurements and is sufficiently accurate
- Where you can afford to measure something directly and either a) don't need to or b) can not afford to monitor the measured value with low latency (immediately?), set a trigger level(s) and transfer information only when the trigger(s) occur(s)
- Where you can not afford to measure everything directly, or model everything all the time, simplify the problem to define some suitable proxy and set a trigger level on that

11.5. Summary of monitoring requirements for HV and LV planning purposes

Measurement of:

- Half-hourly or better averages of bi-directional / four quadrant real and reactive power for each phase of each transformer at primary substations (note that 10-minute or lower time averages are required for control purposes)
- Half-hourly or better averages of bi-directional / four quadrant real and reactive power for each phase of all feeders at primary substations (note that 10-minute or lower time averages are required for control purposes)
- Half-hourly average voltage of busbar at primary substations (note that 10-minute or lower time averages are required for control purposes)
- Half-hourly average bi-directional / four quadrant real power of each phase of each feeder at secondary substations
- Half-hourly average voltage of LV busbar at secondary substations

The accuracy of voltage and current measurements should preferably be 0.5%. It is also useful, but not essential, to have higher time resolution voltage information at the LV busbar and at LV feeder end. Ten-minute average data would be ideal, however this is unlikely to be cost effective. The number of times at a customer's premises that voltage has crossed a defined threshold (set within the statutory voltage limits) within a defined period could provide sufficient early warning of potential voltage excursions within timescales suitable for planning activities to respond to the potential excursion. The time at which such excursions occurred would also be useful.

LV customer smart meters will be able to provide half-hourly customer demand data. This could be aggregated to produce demand data for the majority of individual LV circuits. LV customer smart meters will also be able to provide time data when voltage crosses pre-defined thresholds, which would be useful to determine if the cause of the threshold crossing is known or whether higher time resolution monitoring of the feeder is required. LV customer smart meters will also be able to provide time of voltage excursion.

11.6. Summary of monitoring requirements for HV and LV design purposes

Measurement of:

- Half-hourly or better averages of bi-directional / four quadrant real and reactive power for each phase of each transformer at primary substations (note that 10-minute or lower time averages are required for control purposes)
- Half-hourly or better averages of bi-directional / four quadrant real and reactive power for each phase of all feeders at primary substations (note that 10-minute or lower time averages are required for control purposes)
- Half-hourly average voltage of busbar at primary substations (note that 10-minute or lower time averages are required for control purposes)
- Half-hourly average bi-directional / four quadrant real power of each phase of all feeders at secondary substations
- Half-hourly average voltage of LV busbar at secondary substations
- Ten-minute average bi-directional / four quadrant real and reactive power of each phase of feeders of interest at secondary substations
- Ten-minute averages of voltage, real and reactive power at key points of each phase of feeders of interest
- It is also useful to measure Total Harmonic Distortion (THD) to indicate the presence or otherwise of actual or potential power quality issues

The accuracy of voltage and current measurements should preferably be 0.5%. We propose 10-minute average measurements should be made to IEC 62053 Class 0.5 S. Where power quality issues are known or suspected to be an issue (e.g. customer reporting flicker, significant proportion of feeder power supplied by inverter connected generation) then in addition measurement of:

- Current Harmonic Distortion: Maximum, minimum and average over each 10-minute period for all harmonics up to 50th order + value for Total Harmonic Distortion
- Voltage Harmonic Distortion: Maximum, minimum and average over each 10-minute period for all harmonics up to 50th order + value for Total Harmonic Distortion

In order to implement bespoke circuit ratings:

Asset Type	Measure	Monitor
Overhead Line	Conductor resistance per unit length @ 20°C Temperature coefficient of resistance of conductor Conductor diameter Span length Conductor type Design temperature Time constant of conductor	Load profile Wind speed and possibly direction (not required if using P27 approach) Time period depends on the time constant of the conductor. e.g. for Almond t~4 minutes, whereas for Elm t~17 minutes Accuracy <2%
Cable	Cable size and type, installation, configuration (cable laying formation) Soil ambient temperature Soil thermal resistivity	Half-hourly load profile Accuracy <2%
Transformer	Mass of transformer, windings and oil Losses at no load and rated load Difference between average oil temperature and hot spot temperature Type of cooling mechanism (e.g. fans)	Half-hourly load profile if transformer thermal time constant is one hour or more Oil temperature (if winding hot spot not available) Winding temperature indicator–analogue model for ambient temperature

Table 9: Key inputs to thermal rating calculations

11.7. Summary of requirements for HV and LV control purposes

This includes measurement for local autonomous control (e.g. voltage regulation) and automatic network management (ANM) schemes.

For real-time active management, we propose monitoring of: Voltage measurement accuracy to IEC 62053 Class 0.5 S; Current measurement accuracy to IEC 62053 Class 0.5S.

- For Primary sites (6.6kV, 11kV or 20kV)
  - Voltage, V > 100V step change updated in less than 15-seconds
- For Secondary sites 400V
  - Voltage, V > 1V step change updated in less than 15-seconds
- For all sites
  - Amps,I > 5A step change updated in less than 15-seconds
  - Real power, P > 5kW step change updated in less than 15-seconds
  - Reactive power, Q > 5kVar step change updated in less than 15-seconds
  - Ampacity, A > 5A step change updated in less than 15-seconds

Changes in measured values at a monitoring point which are lower than these indicated values would not be transferred to the control system. The control system would use the most recent previously transferred value in lieu of an updated value.

An advantage of this approach is that it minimises the time required to transfer and process monitoring data, by only transferring those measurements that have changed materially. This minimises system update latency for measurement that are changing fastest. Measurements that are not changing quickly do not require low latency. This approach will increase the responsiveness and accuracy of the control system.

To achieve the full benefits of this approach would require a change from the control system polling RTUs (i.e. pre-emptive scheduling) to a message driven (interrupt-driven) system architecture. This is in line with most modern computer operating systems.

For RTTR on transformers, overhead lines and cables, measurement of the following quantities is recommended. Some of these quantities only require a representative measurement rather than continuous monitoring, which significantly reduces implementation cost of RTTR.

Secondary substations typically have CTs in place for a mechanical maximum demand indicator (MDI). These can be used for a more sophisticated monitoring device satisfying the above requirements (for Planning, design or control purposes), provided that a device can be procured at a sufficiently low price to deliver benefit (a target cost is calculated elsewhere in this document). The marginal cost of shifting from existing CTs to Metering CTs is not high, at least for new equipment.

Asset Type	Measure	Monitor
Overhead Line	Conductor resistance per unit length @ 20°C Temperature coefficient of resistance of conductor Conductor diameter Span length Conductor type Design temperature Time constant of conductor	Current Wind speed and direction Conductor temperature Time period depends on the time constant of the conductor e.g. for Almond t~4 mins, whereas for Elm t~17 mins Accuracy <2%
Cable	Cable size and type, installation, configuration (cable laying formation) Soil ambient temperature Soil thermal resistivity	Half-hourly load profile Accuracy <2%
Transformer	Mass of transformer, windings and oil Losses at no load and rated load Difference between average oil temperature and hot spot temperature Type of cooling mechanism (e.g. fans)	Half-hourly load profile if transformer thermal time constant is one hour or more Oil temperature (if winding hot spot not available) WTI - Winding hot spot temperature (Primaries) Ambient temperature

Table 10: Key inputs to thermal rating calculations

11.8. Monitoring communications

System measurements were made for two purposes:

- To provide data for control systems
- To provide visibility of the network, independent of the control system, sufficient to allow detailed analysis of the efficacy of the methods deployed

GPRS was found to be insufficiently reliable to be used for providing data to control systems. Instead ADSL links were used which were found to be sufficiently reliable.

GPRS links using single provider SIMS were found to be intermittent, insufficiently resilient to provide visibility of the network, even though the requirements (e.g. data latency) were not as onerous as required for control. The GPRS / GSM communication links to monitoring devices were upgraded to a roaming SIM which gave acceptable reliability.

There is a trade-off between monitoring periodicity and practical limitations of communication media (including cost of communications and data processing). Control systems require low latency data which requires high performance communication circuits.

A practical solution which satisfied both of these opposing constraints was identified, tested and used successfully which both minimised data latency and minimised bandwidth requirements. Low latency (15-seconds) data was communicated to the control system only if material changes in the measured quantities occurred.

Conversely, as data for planning and design purposes can be provided with high latency, a highly reliable communication circuit is not required, provided that there is sufficient local storage to buffer data when the communication link is not functional. Providing there are sufficiently frequent, planned regular visits to assets being monitored for other purposes (e.g. periodic inspection) then manual data collection might be a viable option.

Costs

IT and communications costs added 49% to the capital cost of the monitoring equipment. Installation, commissioning and integration etc. added a further 22%. The total cost of a working monitoring system was therefore 171% of the capital cost of the equipment.

There were additional costs resulting from first use of this system, including one-off procurement, contract, systems design, acceptance testing etc. These costs are unlikely to be as high a proportion of system cost for a larger scale BAU system, should a similar system be implemented. These activities added a further 61% of the capital cost of the equipment.

In total, the cost of the monitoring system, comprising more than 150 monitoring points performing more than three million measurements per day, was £850k, of which £336k was the capital cost of the monitoring equipment. It should be noted that the principal use of much of this monitoring equipment was for the purposes of advanced network control.

The maximum cost for a secondary substation monitor to provide data for planning purposes, if all secondary substations were to be monitored instead of using smart meter data, is £78. This figure excludes the cost of CTs on the LV Board for the incoming supply (as these will already be fitted), providing that they are sufficiently accurate. The figure is based on the value to DNOs for planning purposes from smart meters, over RIIO-ED1 and RIIO-ED2 which is reported in the ENA Analysis of smart meter benefits. It is unlikely that a case can be made for ubiquitous secondary substation monitoring for planning purposes.

However, the cost of a temporary secondary substation monitoring device which could be deployed many times to identify true headroom and hence defer reinforcement of LV feeders for one or more years is likely to be significantly lower than the present value of the deferred reinforcement expenditure made possible by the use of the monitor.

Practical issues

Initially GPRS communications were intended to be used but were found to be insufficiently reliable. A combination of ADSL and roaming SIM GPRS provided sufficient reliability, dependent upon usage of the data. See the section on findings from the CLNR project in this executive summary for more details.

Significant enabling works were required to ensure that the data monitoring equipment could be installed and operate successfully and reliably. This included site surveys, site designs, security improvements, IT security upgrades, and working with local authorities to allow better communication coverage via GPRS antennae.

Each site presented different site-specific and data communication challenges. Giving due consideration to these challenges at design stage greatly reduced the amount of 'Monitoring' specific enabling requirements". For example the addition of an extra power socket or an additional duct were considered at the design phase.

The engineering works associated with the systems design, acceptance testing, redesign, commissioning and debugging of this first of a kind product required a significant amount of technical thinking and development time, not only in the design phases and debugging phase of the monitoring system, but also configuring the input outputs to align with the control system.

There are unknown challenges when integrating disparate systems that only surface during the 'doing' stage of integration work. The integration of the new control system, the remote control systems, the network technology and the existing infrastructure at each site included, for example, configuration of the inputs, outputs and modification of digital registers, routing cables between equipment and controllers and the configuration of auxiliary supplies.

We also need somewhere to store all this data, which we might divide into two groups:

- Monitoring for off-line analysis
- Monitoring of the operation of active network management control schemes

Where we collect data purely for off-line analysis, we will need some form of data warehouse. Some distributors already have a single system which collects data from SCADA, customer metering and transmission interface metering. This will get more involved with widespread half-hourly smart metering.

We will bring key analogues associated with the control scheme, e.g. set-points issued, back to core SCADA. This not only provides the control engineer with visibility of what the control scheme is doing, it allows us to use existing data archive facilities to record what the control scheme has done, for off-line analysis. As outlined above, that analysis drives the data we store, so we need to be sure we bring back enough to help work out why the control scheme made its decisions. This becomes significantly more complex when using state estimation and optimisation, so we may then need to use a separate engineering console to track the detailed operation of the system.

Findings from other projects

The following projects have published closedown reports which included details of monitoring:

Project	Lead DNO	Shorthand for this report
Demonstrating the benefits of monitoring LV network with embedded PV panels and EV charging points	SSEPD	SSEPD1
Assessing Substation Measuring Equipment	WPD / UKPN	UKPN1
LV Network Templates	WPD	WPD1
Network Management on the Isles of Scilly	WPD	WPD2
Ashton Hayes Smart Village	SPEN	SPEN1
Hook Norton Low Carbon Community Smart Grid	WPD	WPD3
Low Voltage Network Solutions	ENWL	ENWL1

Table 11: Other monitoring projects

The following conclusions can be drawn from the closedown reports:

- The efficacy of monitoring devices which do not require an outage for installation has been proven
- The GridKey monitoring device appears to be the preferred monitoring device. It was used in projects by four out of the five DNOs that have issued closedown reports on projects that reported on monitoring
- Ten-minute monitoring intervals were adopted by most of the projects
  - Hourly data is adequate for current, real and reactive power measurement
  - For evaluating network performance, 10-minute sampling intervals should be adopted to avoid underestimating voltage impacts
  - There is no significant benefit in adopting shorter sampling intervals, unless input to operational control systems is required
- 0.5% accuracy is preferred for monitoring purposes and can be achieved using CTs. Flexible Rogowski coil sensors have an accuracy of around 2%. However the GridKey rigid Rogowski coil has an accuracy of 0.5%
- The preferred monitoring configuration was to measure voltage at the substation busbar and currents of each phase of every LV feeder at the substation
- The Electricity North West Ltd project 'Low Voltage Network Solutions' developed a special cable joint which incorporated the GridKey sensor, for the purposes of monitoring down an LV feeder
- Communication systems are inherently unreliable although UHF radio is sufficiently reliable for real-time use, all other systems require local storage to avoid loss of data when the communication channel is not available
  - It appears that higher bandwidth and lower latency communication systems are inherently less reliable than lower bandwidth and higher latency communication systems
  - Of the systems used, PLC is the least reliable medium, GPRS is more reliable than PLC and unlicensed radio is more reliable than GPRS
  - GPRS communication is improved by using roaming SIMs and aerial extensions

Note that none of these projects reported the use of ADSL communication links, which were found in CLNR to be reliable and high bandwidth.

Quantities monitored

All of these projects monitored Secondary Substations.

- All measured 3-phase busbar voltage and 3-phase current. SPEN1 and WPD3 measured current on transformer tails only. The others measured current on all LV feeders
- WPD1 and SPEN1 and ENWL1 also measured voltage at feeder end. In addition ENWL1 measured voltage and current mid-feeder and neutral current at all points where current was measured
- WPD1 and WPD3 also monitored customer's premises
- None of these projects have reported monitoring at HV
- The monitors instantaneously calculated the following reported quantities (some monitors were also capable of calculating other quantities that were not reported):
  - Real Power: All projects except WPD2
  - Reactive Power: All projects except WPD1 and WPD2
  - Power Factor: UKPN1, SPEN1, WPD3 and ENWL1
  - THD: SSEPD1, UKPN1 and ENWL1

Voltage and current measurement accuracy:

- To IEC 62053, Class 0.5 S accuracy: WPD1, WPD2, SPEN1, ENWL1
- ±0.5%: SSEPD1
- WPD3 did not quote an accuracy of measurement
- NPL measured the accuracy of a number of units in the lab for UKPN1 high level findings from this assessment were:
  - Flexible Rogowski coil sensors have an accuracy in the region of 2%
  - Sensors by Current (~0.1%) and Locamation (~0.2%) were the most accurate. Gridkey (~0.5%) showed good performance;
  - the accuracy quoted in this study is % of nominal applied current. Figures quoted are for currents between 5% and 100% of FSD. Accuracy was significantly worse than these figures at 1% FSD
- Overall assessment of UKPN1 was:
  - GMC i-Prosys and Gridkey products gained an overall rating of excellent. Both offered advanced monitoring functionality, were easy to install, low relative cost and Plug and Play. Gridkey had better accuracy but hard to access internal electronics, whilst the i-Prosys metrology unit was bulky

Measurement periodicity:

- The intrinsic measurement periodicity of the monitoring instruments was not quoted in any of the reports except UKPN1. This showed a variation from 100mS to one minute. Harmonic measurements to 30th harmonic was reported by SSEPD1 which requires t<0.33mS
- Most projects reported the periodicity of 'measurement samples'. It is assumed that these are averages over the reported sample periodicity of measurements made at the intrinsic measurement periodicity of the instrument used
- Ten-minute measurement intervals are reported by all projects that reported a measurement interval, with the exception of WPD3, which used 15-minute intervals
- ENWL1 found that:
  - Hourly data is adequate for current, real and reactive power measurement
  - For evaluating network performance, 10-minute sampling intervals should be adopted to avoid underestimating voltage impacts
  - There is no significant benefit in adopting shorter sampling intervals, unless input to operational control systems is required

Data transmission periodicity:

- All projects reported different data transmission periods. There does not appear to be a consensus
- Some projects reported that real-time data could be streamed or polled, however there wasn't evidence that this mode of operation was extensively used in the projects
- Some used daily or weekly data upload with local storage, others used half-hourly upload (inferred from the text, it might be that half-hourly data was uploaded less frequently)
- WPD3 used 15-minute periods
- ENWL1 initially used one minute intervals but changed to 10-minute intervals during the project because of issues with the data collection system

Communications

- All projects found that all communication systems were unreliable. Some projects found that a relatively small proportion of monitoring sites produced data over sufficiently long periods to be useable
- In terms of reliability UHF Radio > Unlicensed Radio > GPRS > PLC
- Data storage is essential to avoid data loss due to loss of communications
- In terms of bandwidth and latency PLC > GPRS > Unlicensed Radio > UHF Radio
- It appears that higher bandwidth and lower latency communication systems are inherently less reliable
- GPRS communication is improved by using roaming SIMs and aerial extensions

The findings from these projects support the recommendations that are made in this document, e.g. recommended measurement accuracy and monitoring intervals for different purposes. Where these projects have considered aspects that were considered in CLNR, the outputs of the projects reflect the findings of CLNR. CLNR has gone further than these projects in terms of the types of monitoring locations and use of the monitoring data. For example CLNR monitored at HV and some EHV as well as LV.

In common with the other projects, CLNR found that the reliability of GPRS was improved by using roaming SIMs but still remained unreliable. CLNR took this further and identified that GPRS with local storage is sufficient to provide data for planning or design purposes but is insufficiently reliable to be used for control purposes. None of these projects reported the use of ADSL communication links, which were found in CLNR to provide sufficiently reliable, high bandwidth links for control purposes.

12. FUTURE-PROOFING

12.1. Customers

Introduction

Northern Powergrid's Well Justified Business Plan assumes that the key change in customer practices through RIIO-ED1 (i.e. to 2023) will be the widespread adoption of solar PV. Looking further ahead, into RIIO-ED2 and beyond, it is likely that:

- There will also be increasing volumes of commercial customers with roof-top PV, which will have a similar effect on the network as domestic PV
- EV and HP will exacerbate the winter early evening peak, and perhaps reduce the scope to shift demand (or let assets cool down) overnight; and
- Micro-CHP will trim the early evening peak, but export before breakfast

Other than micro-CHP, these are all potential network killers where clusters of customers choose them. Heat pumps are potentially the most challenging, as we don't really know how they'll behave in a really cold winter, and we have no obvious tools other than conventional reinforcement. Electric vehicles are likely next in line, as customers seem to use them in a way that contributes directly to the existing winter evening peak, and we have not yet found the means to encourage customers to charge overnight, mitigating the impact.

Customers' behaviour in the future is highly uncertain. We don't know how many customers will take up solar PV, heat pumps, or electric vehicles: we don't know how big those units will be, nor do we know how much we can influence EV charging patterns.

Therefore, rather than trying to build a power system (and particularly LVNs) to suit a given scenario, it is more useful to assess what capability we have in existing networks, and also after some modest reinforcement. We can then reduce the design challenge to a simple question of what breaks first, i.e. are we likely to face thermal issue before voltage, or vice versa.

This is consistent with the CLNR philosophy of finding generic solutions to generic problems, so we stand ready to serve our customers as they adopt these new technologies.

Load-drop / generation-rise compensation

For load-drop / voltage-rise compensation, the limiting factor is not the rise on generation-rich feeders, but the drop on load-rich feeders. If we consider load-drop / voltage-rise compensation as something permissive, allowing more generation onto the system when conditions permit, we can also see that the limit of voltage rise compensation is the degree to which we can lower target voltages while still staying above the lower voltage limit on demand-rich feeders.

That is, to safeguard existing customers, we can not drop system volts below the statutory limit. Let's assume that we have one group of customers below an OLTC who still have significant load (import) when another group has significant generation (export); and that the generation is solar PV and we're concerned over sunny summer afternoons. If that first load-rich group is made up of I&C customers, they'll still be taking a substantial proportion of their peak demand even on sunny summer afternoons: some such customers, if they have large air-conditioning loads, may even show their peak demand on sunny summer afternoons. The feeders to those customers will therefore still show a significant voltage drop, which means we can drop the OLTC target voltage only by a limited degree, to avoid falling below the lower statutory limit.

The CLNR test bed networks are reasonably uniform: Rise Carr doesn't feed rural customers, and Denwick has very few industrial / commercial customers. Therefore, we have picked another pair of primaries which do have a more divergent mix of customers, specifically Reservoir (Bedlington, south-east Northumberland) and Northallerton (Ryedale, North Yorkshire). Considering present network and customer demand, we find summer daytime voltage drops, combined across HV and LV, for credible outages, up to 6%.

This shows that, at these two primary substations, we could drop the OLTC target voltage by 6% at times of low demand. However, it seems prudent to drop the OLTC target voltage only so far as we need to accommodate typical customer behaviour.

Our business planning assumption is that by 2050 solar PV take-up will reach a level equivalent to 20% of customers having a 2.5kW installation. If we assume a 90% diversity of output and a summer minimum demand of 0.3kW per connected customer, as we have found in CLNR, this gives us a net export of (20%*2.5*90%)-0.3 = 0.15kW per total connected customer.

To test the sensitivities, let's assume that 25% of customers install a 3.0kW panel, with the same 90% diversity of output but a lower summer minimum demand of 0.25kW per connected customer, which gives us a net export of (25%*3.0*90%)-0.25 = 0.525kW per total connected customer. This confirms that the potential impact is highly volatile.

CLNR LV DVSFs are typically 4 to 7%/kW, suggesting a voltage rise of around 1% for our base planning case and 2.1 to 3.7% for the sensitivity case. We'd also need to allow for voltage rise on the HV network between these LV networks and their nearest point of voltage control, typically a primary substation. As there will be non-domestic load to soak up the export on those feeders, the voltage rise on the HV will be less than on the LV, giving us a base case total rise around 1.0 to 1.5% and a sensitivity case around 3 to 5%. Taking a cautious view, while still covering much of the uncertainty revealed by the sensitivity case, suggests setting up load-drop compensation to give a 3% bias on target voltage, broadly equivalent to the first stage of voltage reduction[25]:

- Set the (no-load) target voltage to 4% below what would just avoid breaching statutory maximum at zero load, e.g. 10.8kV with 102.5% ruling tap
- To avoid going back every year, set the LDC to bias the target voltage by that same 4% (to just avoid stat max) if the load were 10% above the present maximum

For the purposes of this exercise, we will assume that all this 3% is available to urban networks, and that only 2% is available to rural networks, assuming that there is a material HV rise only on the longer rural networks.

[25] Standard practice for many years has been the provision of emergency demand reduction facilities by distributors, to help the transmission system operator cope with unexpected loss of generation margin. To effect demand reduction without customer disconnection, major substations are routinely fitted with the facility to reduce voltage in two or three steps of 3% each.

Low voltage network (LVN) capability

Taking the existing default values for voltage drop (4% rural, 6% urban) and the proposed default values for voltage rise (2% rural, 3% urban) discussed in the preceding section, and the confirmed ratings for LV cables, we have assessed a sample of LVNs to assess their capability to support customers doing new and different things.

We have looked at real networks:

- Wooler Ramsey, on the CLNR Denwick test bed network
- Darlington Melrose, on the CLNR Rise Carr test bed network
- Osmotherley Central, on the Northallerton network

For the rural networks, the default 4% voltage drop limit is generally reached before power flow limits, at loads between 1.6 and 3.2 kVA per customer. If we could accept the same default 6% voltage drop as for urban networks, then voltage and power flow limits would be reached at around the same time, at loads between 2.4 and 4.8 kVA per customer. This is a 50% uplift across the board.

The default 2% voltage rise limit would permit net export of the order of 0.8-1.6 kVA per customer, which is broadly equivalent to half the customers having 3kW installations, which is well above the average take-up we expect. Improving voltage regulation would allow us to accept generation up to the thermal limit of a net export of the order of 2.4 to 4.8 kVA per customer, which covers most plug and play scenarios.

Overlaying with modern standard 300mm^2 waveform releases more voltage headroom than thermal, so voltage drop and power flow limits would be reached at around the same time, at loads of around 3 to 4 kVA per customer. With the default 2% voltage rise limit, permissible net export increases to around 1.5 to 2.0 kVA per customer. The stronger study networks don't benefit from this solution.

At the extreme ends of these scenarios, some secondary transformers might need to be replaced to match the power flow capacity released in the LV mains.

For the urban networks, power flow limits are reached just before the default 6% voltage drop limit, at loads between 2.6 and 3.8 kVA per customer.

The default 3% voltage rise limit would permit net export of the order of 1.3 to 2.0 kVA per customer, which is broadly equivalent to two thirds of customers having 3kW installations, which is well above the average take-up rate we expect. Improving voltage regulation to allow a 6% rise would allow us to accept generation up to the thermal limit of a net export of the order of 2.6 to 3.8 kVA per customer, which covers most plug and play scenarios.

Overlaying with 300mm^2 waveform releases more voltage headroom than thermal, so voltage drop ceases to be an issue. Voltage rise remains a potential issue for PV clusters at the default 3% limit.

Conclusions

From this set of network scenarios, it seems that:

- There is capacity to accept some more load on most existing networks
- With a default 3% load-drop compensation, we can accommodate generation roughly equal to 50% of customers each having 3kW PV on existing rural networks, and 66% of customers each having 3kW PV on existing urban networks. This is well above the average level for the domestic solar PV we expect to connect even by 2050 (20% of customers having a 2.5kW installation)
- If we overlay cables to address thermal issues, this also releases voltage headroom, which is valuable for voltage rise in all areas and voltage drop in rural areas: voltage drop in urban areas is rarely an issue
- In rural areas, improving voltage regulation allows us to accommodate 50% more load and 200% more generation, but we will not often need it; and
- In urban areas, improving voltage regulation allows us to accommodate 100% more generation, but we will not often need it

We can map this to potential customer scenarios:

- With clusters where generation (eg PV) is above 1.5kW/customer on rural networks or 2kW/customer on urban networks, up to the plug and play limit of all customers having just under 4kW each, we reach voltage limits before thermal. We would need to release another 3% in urban areas and up to 9% in rural areas

For existing urban networks, we might often be able to release this headroom by cable overlay. If the local transformer is not otherwise a candidate for replacement, cable overlay may be more economical than rebuilding the local substation to accept an on-load tap-changer, and also provides capacity for further load growth.

On existing rural networks, the amount of voltage regulation required leads to installing HV regulators. This also unlocks existing thermal capacity otherwise constrained by voltage issues;

- For high load scenarios, we'll generally reach thermal limits before voltage on urban networks, which leads to cable overlay. This will also release voltage headroom for generation

On rural networks, high loads breach voltage limits before thermal, and cable overlay yields only limited benefit. This leads to installing HV regulators, which will also release voltage headroom for generation.

12.2. Technology

12.2.1 Future smarter substations

The benefits of adding smartness to existing substations as a matter of routine are unclear.

However, it would be prudent to make the following small changes to our specifications to make our new-build substations smart ready:

- We may need to easily change distribution transformers for bigger units and/or OLTC, which may move away from the present convention of a UDE and back towards cable-coupled units. This could yield additional advantages in opening up the option of corrugated-tank transformers
- The required tapping range for a secondary OLTC is relatively modest. In the absence of customers who disrupt voltage profile on the HV network, we need to provide only a 3% buck to accommodate as much PV as the thermal capacity of the LV cables permits; and
- If deploying transformer RTTR in earnest, we may need bigger bushings/OLTC/cable loops, because these ancillaries will be the limiting factor if we get more out of the main tank

12.2.2 Future smarter feeders

If we seek to exploit the full potential of OHL real-time or dynamic ratings, we may need to over-size cable sections on the feeder route, and perhaps switchgear (or at least CTs).

13. LOSSES

All networks consume energy as a consequence of transporting energy. Gas networks consume energy to drive compressors; electric networks consume energy to charge dielectric and magnetic circuits, and in conductor resistance.

The amount of leakage in electric networks compared to gas or water networks is negligible; only corona loss can be said to escape the conductor.

Copper losses follow the square of the current, so small increases in demand give bigger increases in losses. Deferring reinforcement means we place a higher demand on a given asset, so copper losses will rise; iron losses will remain fixed. Even if the peak demand remains unchanged, perhaps through the use of real power response services, the rest of the load curve will rise, so copper losses across the year will rise.

This is a specific case of the general principle that smarter solutions reduce one-off costs but increase annual costs.

“Copper losses follow the square of the current, so small increases in demand give bigger increases in losses. Deferring reinforcement means we place a higher demand on a given asset, so copper losses will rise; iron losses will remain fixed. Even if the peak demand remains unchanged, perhaps through the use of real power response services, the rest of the load curve will rise, so copper losses across the year will rise.

14. CONCLUSIONS

This section summarises previous work to outline the steps which a distribution system designer might follow in more effectively addressing emerging network constraints. It makes no predictions as to future customer behaviour but has regard to future changes and thereby does make reasonable provision for flexible future networks.

14.1. Design demands

We have calculated new values for the coefficients used in the standard industry model, as laid down in ENA ACE reports 49 and 105. These show that the contribution of domestic customers to system maximum demand falls from 1.58kW to 0.91kW.

We have applied the same method to characterise new customer choices, specifically solar PV, electric vehicles and heat pumps. Broadly speaking, the first comes in at about 90% of aggregate declared capacity per PV installation, less about 0.3kW domestic summer minimum demand per connected customer with or without PV, and the last two double the winter domestic demand curve.

We also propose to reduce the credit for the contribution of wind generation to system security to reflect our findings. For the key three-hour timeslot, we suggest a contribution of 14% rather than 24%.

14.2. Merit order - thermal

This section considers each solution in turn, and then draws conclusions on a merit order.

Better monitoring will confirm whether or not there is an issue. If we measure the right things and apply them to the right model we can provide a bespoke rating assessment which should release capacity in itself.

RTTR is not a solution in itself. It is a necessary prerequisite for the active control of real power across the network, but does not itself change the capability of the network. We can not hang an FMCTech monitor on a line and claim that the line now has a higher rating (although, after a year or so, studying the data might allow the design rating to be revised).

We can always make DSR/GSR (used for general network support[26]) viable by pricing it at slightly less than the cost of the other solutions. The question then becomes how much capacity customers will make available at that price. CLNR results show that there is scope to engage customers across the spectrum, although there is still some work to do to stimulate the development of that market. Therefore, it's always worth trying to engage some customers to defer major reinforcement.

Looking forward, this generalisation might also be applied to EES, particularly if we consider it as a service for which we might tender rather than as an asset we would own. That is, if the load curve has a distinct peak over a few hours, as most customer groups do, then we can issue a tender for a generic real power response service: we would remain largely indifferent as to whether our service providers used stand-by generation, energy storage, genuine load reduction, or some combination thereof.

When tendering for real power response, we should recognise that different providers will have different characteristics. It is therefore appropriate to break the required response down into shaped blocks (e.g. shoulders and core, or into 2x2hr blocks rather than 1x4hr block) to bring more providers into the market.

We should recognise that, with area control, a real power response service can address multiple issues and therefore deliver multiple benefits. As we're initially looking at applying this to the primary system, we can afford to invest in a case-specific analysis of present and likely future constraints.

All real power response services require some form of controller, to call for that response as the relevant asset(s) approach their thermal limits. Where there is only one constraint on a given section of network, even if there are multiple service providers, a smart RTU near that constraint is the simplest and cheapest solution. Where there are tiered constraints on a given section of network, some form of area controller becomes viable.

The control loop may be driven from limits that are either pre-set or calculated in real-time, i.e. RTTR. If we're looking to secure load, then RTTR releases no more capacity than pre-set limits, but it can reduce the call for real power response services. RTTR comes into its own when associated with non-firm connections, which are outside the scope of CLNR.

Where we apply real power response to an asset with a cyclic rating then, for planning purposes, we will need to recalculate the planning cyclic rating to reflect the new, flatter load curve.

Reactive power response is generally of little benefit for thermal issues, as the networks run close to unity power factor.

Where a real power response service is unavailable, we're left with conventional reinforcement or, where the thermal issue is associated with LVN unbalance (e.g. for PV), unbundling looped services and rebalancing the demand across all available phases.

14.3. Merit order - voltage

Turning to voltage, better monitoring and modelling will again confirm whether or not there is an issue.

CLNR has also shown that better control of existing assets can yield significant headroom, particularly for solar PV, as previously discussed. Specifically, it is proposed here that we apply existing line-drop compensation features to drop the target voltage by 3% at times of low load.

Where the combined effect of this better control of existing assets and any reinforcement required for thermal constraints is insufficient, for example where PV is clustered, additional measures will be required, the first of which should be a bespoke study for LDC settings on that network.

CLNR shows that the discussion on a real power response service for thermal constraints also applies here, so it is always a solution that should be considered for voltage constraints as well.

For voltage control, we should also consider reactive power services. Many generators can control their reactive power within limits without installing additional equipment, making this a cost-effective solution:

- Medium embedded generators are bound by the Grid Code. Amongst other provisions, allows the host distributor to require the generator to operate in P-V mode. This is varying the reactive power to control the voltage, with a neutral mid-point voltage and a VAr/V slope defined by the distributor
- Small embedded generators, above a de minimis threshold, can run at a fixed but controllable power factor. Changing the power factor as requested by the distributor is already in many connection agreements and, within the capability of the generators' existing plant, would be a reasonable change to older, existing connection agreements

Where the voltage issue is associated with LVN unbalance (e.g. for PV), it can be addressed by unbundling looped services and rebalancing the demand across all available phases. This will also address power quality issues and postpone future thermal issues.

After this, we need to add more voltage control resources. CLNR has confirmed that constraints emerge because the setting on any single device has to be a compromise for all the customers it serves: clever control schemes have only a limited ability to find a better setting, and come into their own when there are multiple resources whose settings can be coordinated. The big gains come from providing a new voltage control resource to manage divergent sections of network: this not only releases capacity for that local section but also, by reducing the degree of compromise required of existing resources, releases capacity there as well.

Capacitors have advantages and disadvantages compared to regulators:

- Capacitors can only buck, not boost. This works well for load-rich networks, and could in theory be made to work if re-engineering generation-rich networks. In practice, as we foresee issues arising mainly due to voltage rise, and incremental solutions are generally most economical, the ability to buck has some value
- Capacitors move the voltage at their connected busbar, so they manage volts both upstream and downstream
- When over-compensating to reach their target voltage, capacitors can drive VArs back up through the primary transformers, as we have often seen on the CLNR test-bed networks. While all customers behave the same, so all voltage control devices are moving in similar directions, this is not an issue. However, as customers become more diverse, creating excess voltage rise in another part of the network could become a problem

Previous analysis suggests that rural networks will see more widespread voltage issues than urban networks, and the former will also see voltage issues for load as well as generation. This tends towards HV regulators better to manage larger groups of rural customers and HV / LV OLTC to manage clusters of urban customers.

Where adding HV / LV OLTC is considered, it should be costed against LV cable overlay. Unless there is a simultaneous need to replace the existing HV / LV transformer, it will often be cheaper to reduce LV network impedance. This also creates more thermal headroom for future growth scenarios.

By contrast, adding HV regulators to rural networks also unlocks existing thermal capacity on existing networks generally constrained by voltage drop and rise.

Once we have more active control devices, whether non-network (e.g. controllable DG) or network, their benefit can be optimised through a coordinating area control system. This may require amending some agreements, for example moving Medium generators from P-V mode to responding to MW and MVAr set-points issued from the control system.

[26] It is assumed here that the principle of constrained non-firm interruptible connections, which has not been tested in CLNR, is well proven and familiar to the reader

All this can be summarised as:

Identify the issues

- Model the system to identify potential capability gaps
- Where necessary, monitor to validate the model

For thermal issues:

- Where cost-effective, carry out a bespoke thermal rating study, e.g:
  - Transformer thermal tests
  - Soil thermal resistivity tests
  - Wind speed measuring/modelling
- Invite tenders for DSM (DSR, GSR and EES), priced against deferring the lowest cost conventional alternative
- Where multiple DSM resources exist, capable of addressing multiple series power flow constraints, deploy an area coordinating control scheme
- Reinforce where required to close the remaining capability gap

For any remaining voltage issues

- Apply default 3% load-drop / generation-rise compensation setting on all active voltage control devices
- Carry out bespoke voltage setting analysis for:
  - Increased load-drop / voltage-rise compensation settings
  - Tighter dead-bands
- Where contracts permit, direct controllable DG to operate with bespoke reactive power settings (e.g. P-V mode)
- Where contracts permit, direct controllable DG to operate with bespoke real power settings (e.g. trimming real output to avoid breaching a defined upper voltage limit at the terminals)
- Invite tenders for a DSM (here, for both real and reactive power, to address voltage issues), priced against deferring the conventional alternative
- Deploy as many additional control devices as required, with bespoke analysis of settings:
  - In urban areas, OLTC at the local substation serving the affected cluster, but compare to the cost of LV cable overlay
  - In rural areas, HV regulators
- Deploy area control to coordinate the set-points of voltage control devices (including constrained DG)
- Reinforce where required to close the remaining capability gap

15. FURTHER WORK

15.1. ESQCR drafting

There are some quirks of the drafting of ESQCR which have always needed review, but which CLNR highlights, specifically:

- The absolute nature of the voltage limits
- The absolute sufficiency requirement of regulation 3; and
- The requirement of regulation 17 that the height above ground of any overhead line, at the maximum likely temperature of that line, shall not be less than that specified in the regulations

CLNR has reinforced the growing consensus that absolute voltage limits and unpredictable customer demand are not consistent. It would be more practical to endorse the BS EN 50160 approach, that during each period of one week 95% of the 10-minute mean r.m.s. values of the supply voltage shall be within the range of Un ± 10%; and all 10-minute mean r.m.s. values of the supply voltage shall be within the range of Un + 10% / - 15%.

For overhead lines, the maximum temperature depends upon load and weather conditions, neither of which can be predicted perfectly. Therefore, we need to agree a practical basis on which to assess what we mean by 'likely' conditions and therefore what would be 'sufficient'.

15.2. Commercial arrangements

Reflecting back to the CLNR-L145 Commercial Arrangements report:

- There is benefit for distributors in working with suppliers and aggregators to stimulate demand side participation across all customer groups, particularly for customers with electric vehicles ahead of mass roll-out
- Facilitating the development of ToU tariffs requires a consistent approach to pricing capacity, whether generation, transmission or distribution

15.3. More granular data

The project has produced large amounts of (highly disaggregated) HV and LV monitoring data on a very fine time scale. This provides the inputs to update understanding of how the rules used for network design (ADMD per customer etc.) work in practice, and how long-term averaged data (e.g. 30-minute maximum demand) relates to short-term loading as the number of customers varies. This will be especially important for any assets on the network which have short overload periods (e.g. OHL, maybe solid state inverter systems), and also to what data is needed to decide when the LV network is really overloaded.

This may lead to changes in monitoring standards.

15.4. Area control compare and contrast

Across CLNR and other projects, area control schemes which differ in their detailed design have been deployed. As these initial projects are closed out, there is value in comparing implementation / maintenance costs against the benefits yielded.

15.5. Customer demand

We need to understand what maximum demand heat pumps could credibly make upon the network.

We need to work out ways to persuade customers with electric vehicles to charge them off-peak.

15.6. Asset thermal rating

For cable bespoke ratings, CLNR has shown that ground conditions can vary widely in a relatively compact area, i.e. within the Rise Carr network. To inform bespoke (and even new generic) cable ratings, we need better information on soil thermal resistivity, so we need to dig some more holes.

For OHL RTTR, further work is required to generalise the CLNR exceedance curves for other conductor sizes.

APPENDIX 1: VOLTAGE CONTROL POLICY

Let's refer everything back to a 230V base. The statutory limits are +10%, -6%, allowing us from 216.2 to 253.0V.

If we control this using an on-load tap-changer, as is generally the case, we need to recognise that the voltage control relay has a dead-band which reflects the fact that the tap-changer moves in discrete steps; we also need to allow for errors in measuring voltage at the point of control. Typically, we would allow 2% either end, allowing us 220.8 to 248.4: this is a 12% range.

We need to allocate this permissible voltage range across our customers. Until recently, almost all our customers imported power from our networks, rather than exporting onto it. We could therefore efficiently and economically allocate all of the voltage range to the voltage drop caused by import. This allowed us to set OLTC target voltages at the very top of the range, i.e. 248.4V, so we could be confident in not exceeding the upper voltage limit even for close-in customers at times of low load, and so we could use all that headroom for import.

All networks have some impedance and therefore some voltage drop (or rise). Conventionally, we control voltage at the interface between EHV and HV networks, so the 12% drop available was allocated across HV and LV networks, out to the point of delivery to the end customer. For urban networks, this is typically split evenly between the two networks, so we have a 6% drop (from the target voltage of 248.4V to 234.6V equivalent) on the HV network and a further 6% drop (from that 234.6V to our lower limit of 220.8V) on the LV network. For rural networks, we expect longer runs at HV and shorter runs at LV, so we allow a 8% drop (from the target voltage of 248.4V to 230.0V equivalent) on the HV network and a further 4% drop (from that 230.0V to our lower limit of 220.8V) on the LV network.

As more of our customers export power back onto the network, it becomes efficient and economical to allocate some of the permissible voltage range to the voltage rise caused by that export. Present practice at Northern Powergrid, supported by the outcomes of WPD's LV Network Templates project, is to reduce OLTC target voltage by 1%, broadly equivalent to a move from 248.4V to 246.1V (which equates to 11.1kV for 11,000/433V transformers on 102.5% tap). This allows a small headroom for generation, but in consequence reduces the permissible voltage drop across the HV and LV networks. Broadly speaking, we allocate the same 6% drop to urban HV networks (taking us from this new target voltage of 246.1V down to 232.3V), meaning that we have only 5% available for voltage drop on an urban LV network (from that 232.3V to our lower limit of 220.8V). In practice, this causes a negligible volume of voltage issues for our customers.

Trials and additional studies show we can reduce target voltage by up to 6%. This benefit depends on the mix of customers: for example, if we considered only regular domestic customers, we could reduce the target voltage by 9%; by contrast, city centres dominated by air conditioning barely change all year.

As shown in CLNR_DEI-149, we need to find a compromise setting for the mix of customers we see. If we consider LDC as permissive, then the maximum voltage drop allowed is driven by the customer group with the highest load at the time. This is driven more by the number of control devices we have than the complexity of the control scheme: as long as we have a suitable reference point, a well-calibrated LDC scheme can deliver almost all the benefits of a coordinated controller.

If we accept a variable change in target voltage of up to 3% according to load, we can move away from the default 1% reduction (246.1V equivalent), and instead apply target voltages between the upper permissible limit (248.4V equivalent) and 3% below it (241.5 equivalent). This means we get back the full 12% permissible voltage drop (248.4 to 220.8), to help accommodate new loads as customers take up heat pumps and electric vehicles, and we can also extend the voltage headroom for PV from 1% to 3%.

This translates into typical settings of:

- 11,000 / 433V, 102.5%: 10.8kV no-load target voltage, with a LDC setting of 4% relative to present maximum demand + 10%, giving an effective target voltage range of 10.9-11.2kV
- 20,000 / 433V, 102.5%: 19.5kV no-load target voltage, with a LDC setting of 4% relative to present maximum demand + 10%, giving an effective target voltage range of 19.7-20.3kV

Where this 3% headroom for generation is insufficient, or where we have voltage drop issues due to load, a bespoke analysis is required. Where we have a particularly generation-rich network, and we have issues only with voltage rise and not with voltage drop, the designer shall assess dropping a tap on the secondary transformer, e.g. from 102.5% to 105%. Broadly, this gives voltage limits for that LVN of a 6% rise and 3% drop rather than the generic 3% rise and 6% drop.

If this is insufficient, the designer shall assess whether the load-drop compensation settings can be made more aggressive without compromising statutory limits.

If this is insufficient, then additional voltage control resources shall be deployed. The designer shall assess the outlying part of the network which diverges most from the average, and fit a secondary OLTC in urban areas or an additional HV regulator in rural areas.

APPENDIX 2: THERMAL RATINGS POLICY

For default ratings, the existing engineering recommendations P15 (transformers), P17 (cables) and P27 (overhead lines) shall be used, with the following variations:

a. ER P15 shall be applied to any CMR transformer, not just those with a primary voltage of 132kV

b. For substations supplying summer peaking loads, a cooling air temperature of 30°C shall be assumed

c. For cables supplying winter peaking loads, a soil thermal resistivity of 1.5 W/K-m shall be assumed

d. For cables supplying summer peaking loads, a soil temperature of 20°C and a soil thermal resistivity of 2.0 W/K-m shall be assumed

For bespoke enhanced ratings:

a. For cables, soil samples shall be taken every kilometre, to establish the drying-out curve and hence predict thermal resistivity. This shall be used to replace the default values discussed above to select the appropriate P17 correction factor

b. The thermal characteristics of the transformer shall be modelled by on-site temperature rise tests in accordance with IEC 60076

c. Wind speed measurements shall be taken from a site within 20km, reduced to 10% to reflect the effects of sheltering, unless site-specific measurements are available

d. Demand curves shall be taken from SCADA records, for similar customers where no specific record exists (e.g. for new connections)

e. Standard non-proprietary time-series models (e.g. CP 1010, IEC 354, IEC 60076 or CIGRE technical bulletins) shall be used to estimate the peak demand which can be carried without exceeding rated hot spot:
   - For transformers, limiting hot spots of 130°C for sub-transmission transformers and 140°C for primary transformers shall be used
   - For overhead lines, excursions lasing less than the thermal time constant may be ignored

For full real-time thermal ratings:

a. Standard non-proprietary time-series models (e.g. CP 1010, IEC 354, IEC 60076 or CIGRE technical bulletins) shall be used

b. For transformers, only load current and the temperature of the cooling air are required

c. For overhead lines, only wind speed is required. This may be taken from a site within 20km, with values reduced to 10% to reflect the effects of sheltering. As it can be difficult to define in advance the most sheltered span, and because radio communication is unreliable, measurement at the primary is preferred to measurement from remote sites

APPENDIX 3: DEMAND SIDE MANAGEMENT POLICY

Purpose

This section lays out our policy on Demand Side Management (DSM) based on the findings of the CLNR project and other LCNF projects. DSM is a broad term 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. Examples of DSM include but are not limited to:

- Demand side response (DSR)
- Energy efficiency / reduction
- Energy storage services (could be thermal storage, EES, etc.)
- Distributed generation
- Dynamic pricing
  - Time-of-use (ToU)
  - Location of use (LoU)
- Increased or flexible demand devices (electric vehicles and heat pumps)

Philosophy

DSM can potentially offer significant economic and environmental advantages to the conventional BAU solutions currently deployed to overcome network constraints.

It can be contracted annually (allowing it to be turned off if not required in future years), which is particularly advantageous in the current era of annual load reduction. It is often environmentally beneficial (as DSR causes little or no impact on the environment) and it provides a financial benefit to customers. For these reasons it is our policy that during RIIO-ED1, DSM should always be the first solution considered when a network constraint is identified and it should be selected as long as it is available in sufficient quantities to guarantee delivery and is cost neutral to the next most economical solution. With further refinement of our understanding and application of DSM through RIIO-ED1 it should be possible to identify a more firm economic and technical understanding of the benefits and application of DSM and this philosophy will therefore be expected to evolve.

> “It is our policy that during RIIO-ED1, DSM should always be the first solution considered when a network constraint is identified and it should be selected as long as it is available in sufficient quantities to guarantee delivery and is cost neutral to the next most economical solution.

Background

The findings from the CLNR project and other studies have confirmed that DSR, GSR and EES (real) all have the same effect. Our own DSR paper shows that ‘DSR’ is often really GSR, as customers offer up generators otherwise used for stand-by power, rather than offering up reductions in underlying consumption. Therefore we identify DSR, GSR and EES as all being options of different types of real power dispatch which deliver the same network benefit.

It is assumed here that DSM is equivalent, as:

- When seeking day-in day-out response from customers as a whole, we’d set tariffs to reflect the avoided cost of other solutions
- We treat storage on the same basis as customer response, i.e. a contracted service rather than owning it ourselves; and
- When seeking an on-demand response to a particular constraint (or set of tiered constraints), we’d set a ceiling at the equivalent cost of other solutions when tendering. To ensure that customers as a whole benefit from the most efficient solution, we would:
  - Pay as bid, so that customers don’t over-pay; and
  - Apply the ceiling to average cost, so that if the aggregate cost of the DSR scheme is less than reinforcement, we’d go for DSR

For on-demand response, the key cost component is the ‘insurance policy’ element because, in practice, we’d rarely call for the response. That cost component is the availability charge within STOR-like contracts; for storage, we’d expect that charge to reflect the capital cost. No matter how the response is provided, the energy component of cost will be small because of the infrequent nature of the requirement for such a response.

Delivering DSM

Potentially, we can access EES, DSR and GSR, and we should not rule any out. These three mechanisms can effectively be considered to be similar and the guidance for delivering DSM options is laid out in essence in the two following DSR documents:

- CLNR-L160 DSR Application Guide
- CLNR-L145 Commercial Arrangements

However, it should be borne in mind that both the costs and delivery mechanisms for DSM should be expected to evolve over time, not only as our understanding increases but also as the volume of contracts potentially increases, in all of the following areas:

IT and monitoring requirements

The building block for a DSM infrastructure is the smart RTU as developed for the CLNR project, running:

- Thermal modelling
- Thermal management
- DSR management

This can be expanded into coordinated control where multiple series constraints, which might usefully access the same DSR resource, arise.

Identifying DSM providers

Another learning point from the CLNR project is that DNOs are currently in the early stages of using DSM and are therefore not as good at sourcing DSM as they will eventually become. It is expected that in most cases early DSM will come from aggregators, although some relationships have already been built with individual companies. Further alternatives should not be ruled out and if cost effective options are identified, these should also be identified for the application guide.

Availability factors

A final learning point is the development of F-factors for DSM to replicate those already available for GSR. It should be recognised that these F-factors are still in development and future learning should be expected and again should be transferred into the application guide.

Merit order

Finally, as the market for DSM increases instances may arise where more DSM is available than is required to satisfy the need. In this instance we would adopt the following merit order for DSM:

- Least cost
- If equal cost – DSR first then EES, lastly GSR (based on environmental factors)
- Diversity

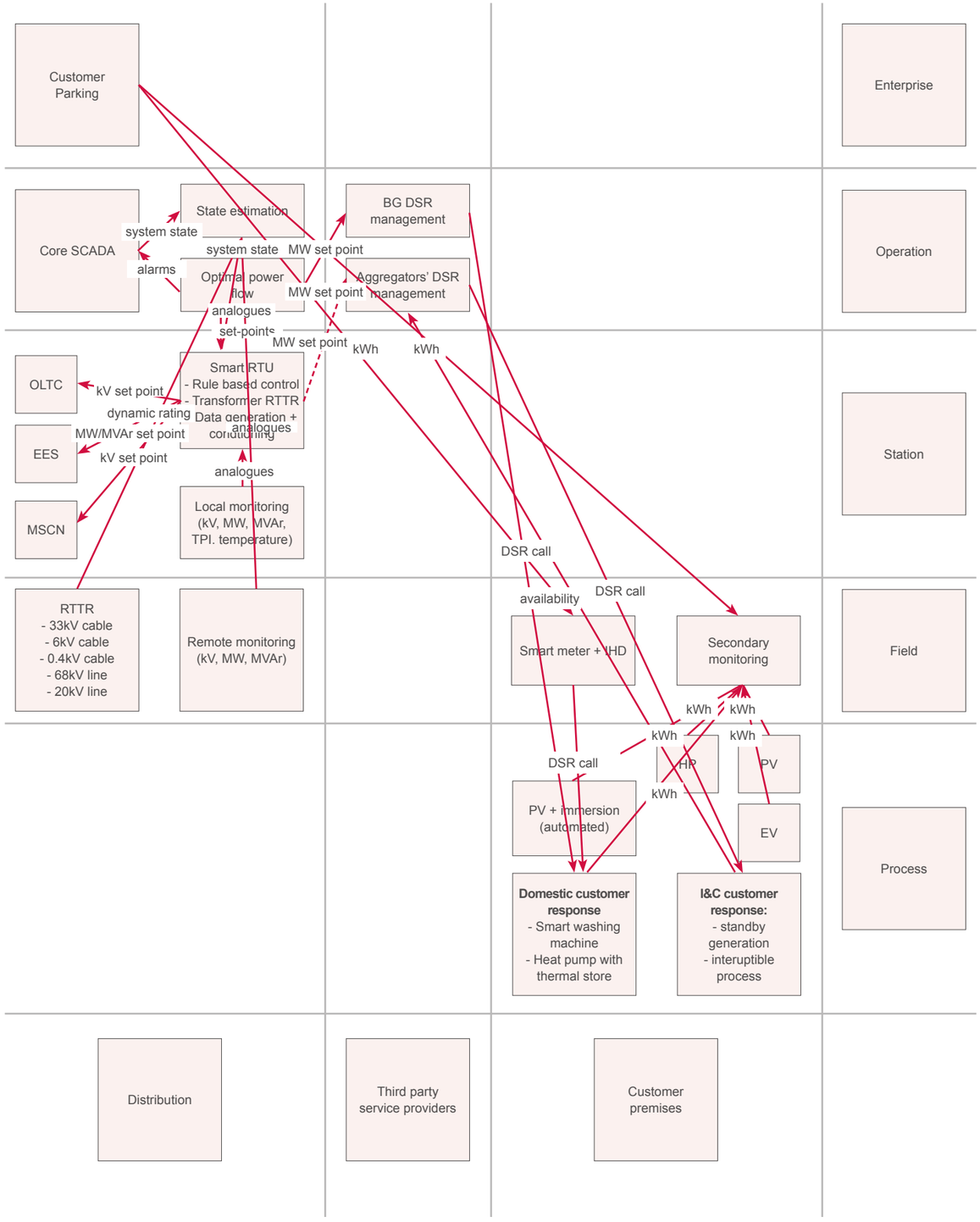
Note that different forms of DSM are likely to have different availability factors and this will need to be factored in to the cost calculation.

Developing the market for DSM

The approach outlined above provides a first step approach to determining the price to offer the marketplace for DSM. This marketplace for the provision DSM to DNOs is in its infancy. It should be expected that, with further experience, current uncertainties as to availability and reliability of DSM as well as acceptable market pricing will become better understood. Following this approach for DSM over the RIIO-ED1 cycle, we expect to maximise the number of DSM opportunities identified within the region and gain experience to allow us to provide benefits to the customer and the environment and to further improve the efficiency and understanding of DSM, towards ED2 and beyond. This should allow us to maximise the financial benefit of DSM into ED2 and also produce a keener pricing strategy.

Developing partnership approaches with other DNOs and with National Grid will help increase both the speed of learning and the development of contacts for DSM; these relationships (and others as appropriate) should be actively sought.

APPENDIX 4: SCHEMATIC OF THE CLNR SYSTEM



APPENDIX 5: RELATED DOCUMENTS

Subject Area	Detailed Paper		Optimal Solutions Report - Section References
Domestic and Business Load Profiles	CLNR-L010	Initial load and generation profiles from CLNR monitoring trials	Design Demands The Contribution of Generation to System Security
	CLNR-L011	Dataset to accompany CLNR-L010	
	CLNR-L185	Review of the Distribution Network Planning and Design Standards for the Future Low Carbon Electricity System (including recommendation for ETR130)	
	CLNR-L217	After Diversity Maximum Demand (ADMD) Report	
	CLNR-L246	Developing the smarter grid: the role of domestic and small and medium sized enterprise customers	
Demand Side Response	CLNR-L014	Initial Report on CLNR Industrial and Commercial Demand Side Response Trials	Real Power Despatch (Thermal) Real Power Despatch (Voltage)
	CLNR-L098	Report on CLNR Industrial and Commercial Demand Side Response Trials	
	CLNR-L160	Application Guide: CLNR Demand Side Response Trials	
	CLNR-L258	DSR Ceiling Price Calculator	
	CLNR-L247	Developing the smarter grid: the role of industrial and commercial and distributed generation customers	
Thermal Rating	CLNR-L263	A Review of Engineering Recommendations P15, P17 and P27 (Transformers, Cables and Overhead Lines)	Enhanced Thermal Ratings
Voltage Control	CLNR-L257	Voltage Control Policy: Proposals for a Voltage Control Policy from CLNR Learning	Over-/Under-Voltage
Approach to the Trials	CLNR-L221	CLNR Learning Credits System	Method
	CLNR-L220	Overview of Network Flexibility Trial Design for CLNR	
	CLNR-L023	CIRED 2013: Programmatic smart grid trial design, development and analysis methodology (CIRED paper #0938)	
Post-Trial VEEEG Reports (produced by Newcastle University)	CLNR-L116	CLNR Trial Analysis: I&C Demand Side Response and GUS Voltage Control	Real Power Despatch (Voltage)
	CLNR-L117	CLNR Trial Analysis: I&C DSR for Powerflow Management	Real Power Despatch (Thermal)
	CLNR-L118	CLNR Trial Analysis: Electrical Energy Storage (100kVA/200kWh) Powerflow Management	Real Power Despatch (Thermal)
	CLNR-L119	CLNR Trial Analysis: EES1 and EAVC1 with GUS Voltage Control	Combinations (Voltage)
	CLNR-L120	CLNR Trial Analysis: EES2 and EES3 + GUS Powerflow Management	Real Power Despatch (Thermal)
	CLNR-L121	CLNR Trial Analysis: Electrical Energy Storage (2.5MVA/5MWh) Powerflow Management	Real Power Despatch (Thermal)
	CLNR-L122	CLNR Trial Analysis: EES3 Autonomous Voltage Control	Shunt Reactive Compensation (Voltage) Real Power Despatch (Voltage)
	CLNR-L124	CLNR Trial Analysis: HV Regulator Autonomous and Single and GUS Voltage Control	Coordinated Control
	CLNR-L125	CLNR Trial Analysis: Capacitor Bank Autonomous and Single + GUS Voltage	Shunt Reactive Compensation (Voltage) Coordinated Control

Subject Area	Detailed Paper		Optimal Solutions Report - Section References
Post-Trial VEEEG Reports (produced by Newcastle University)	CLNR-L126	CLNR Trial Analysis: Tapchanging Secondary Transformer Automonous and GUS Voltage Control	Spur OLTC Coordinated Control
	CLNR-L127	CLNR Trial Analysis: EHV and HV for Real Time Thermal Rating Trials	Enhanced Thermal Ratings Real Power Despatch (Thermal)
	CLNR-L130	CLNR Trial Analysis: RTTR for Secondary Transformers	Enhanced Thermal Ratings Real Power Despatch (Thermal)
	CLNR-L131	CLNR Trial Analysis: Real-Time Thermal Rating for Underground Cables	Enhanced Thermal Ratings Real Power Despatch (Thermal)
	CLNR-L135	CLNR Trial Analysis: Collaborative Voltage Control on HV and LV Networks	Enhanced Voltage Control Coordinated Control
Operational Guidance	CLNR-L161	Operational Guidance and Training Requirements: Electrical Energy Storage Systems	Real Power Despatch (Thermal) Shunt Reactive Compensation (Voltage) Real Power Despatch (Voltage)
	CLNR-L157	OHL Real-Time Thermal Rating Installation Guide	Enhanced Thermal Ratings
	CLNR-L158	Operational Guidance and Training Requirements: Trials of Secondary Transformers with Integral OLTC	Spur OLTC
	CLNR-L156	Operational Guidance and Training Requirements: Grand Unified Scheme (GUS)	Coordinated Control
Network Trials Lessons Learnt Reports	CLNR-L163	Lessons Learned Report: Electrical Energy Storage	Real Power Despatch (Thermal) Shunt Reactive Compensation (Voltage) Real Power Despatch (Voltage)
	CLNR-L164	Lessons Learned Report: Real-Time Thermal Rating	Enhanced Thermal Ratings
	CLNR-L165	Lessons Learned Report: Enhanced Automatic Voltage Control	Enhanced Voltage Control Spur OLTC
	CLNR-L167	Lessons Learned Report: Grand Unified Scheme	Coordinated Control
Network Monitoring	CLNR-L232	Enhanced Network Monitoring Report	Monitoring
Power Quality	CLNR-L146	Power Quality Assessment - Impacts of Low Carbon Technologies	Power Quality

Subject Area	Detailed Paper		Optimal Solutions Report - Section References
Technical Recommendations for Purchase	CLNR-L147	Technical recommendation for the purchase of EES systems	Real Power Despatch (Thermal) Shunt Reactive Compensation (Voltage) Real Power Despatch (Voltage)
	CLNR-L149	Technical recommendation for the purchase of overhead line RTTR systems	Enhanced Thermal Ratings
	CLNR-L150	Technical recommendation for the purchase of RTTR for transformers	Enhanced Thermal Ratings
	CLNR-L151	Technical recommendation for the purchase of underground cable RTTR systems	Enhanced Thermal Ratings
	CLNR-L209	Technical recommendation for the purchase of EAVC for HV systems	Enhanced Voltage Control
	CLNR-L210	Technical recommendation for the purchase of EAVC for HV-LV systems	Enhanced Voltage Control
	CLNR-L154	Technical recommendation for the purchase of EAVC for HV-LV systems	Coordinated Control
Training Materials	CLNR-L168	Training Package: Electrical Energy Storage	Real Power Despatch (Thermal) Shunt Reactive Compensation (Voltage) Real Power Despatch (Voltage)
	CLNR-L204	Training Package: Real-Time Thermal Rating for Overhead Lines	Enhanced Thermal Ratings
	CLNR-L205	Training Package: Real-Time Thermal Rating Underground Cables	Enhanced Thermal Ratings
	CLNR-L206	Training Package: Real-Time Thermal Rating for Transformers	Enhanced Thermal Ratings
	CLNR-L170	Training Package: Enhanced Automatic Voltage Control	Enhanced Voltage Control
	CLNR-L172	Training Package: Active Network Management	Coordinated Control
	CLNR-L173	Training Package: Demand Side Response	Real Power Despatch (Thermal)
Commercial Arrangements	CLNR-L032	CLNR commercial arrangements study: review of existing commercial arrangements and emerging practice (2013)	Real Power Despatch (Thermal)
	CLNR-L145	Commercial arrangements study – Phase 2 (2014)	Real Power Despatch (Thermal)

Subject Area	Detailed Paper		Optimal Solutions Report - Section References
Cost Analysis	CLNR-L144	Cost Benefit Assessment of the Customer-Led Network Revolution Project	Conclusions
	CLNR-L256	CLNR Solutions Templates	Conclusions
	CLNR-L249	Cost Analysis Report: Electrical Energy Storage	Real Power Despatch (Thermal) Shunt Reactive Compensation (Voltage) Real Power Despatch (Voltage)
	CLNR-L250	Cost Analysis Report: Enhanced Automatic Voltage Control	Enhanced Voltage Control Spur OLTC
	CLNR-L251	Costs Analysis Report: Grand Unified Scheme (GUS)	Coordinated Control
	CLNR-L252	Costs Analysis Report: Real-Time Thermal Rating	Enhanced Thermal Ratings
Network Planning Design Tool	CLNR-L155	NPADDS Enduring Specification	
	CLNR-L255	NPADDS Prototype Functionality and Benefits Case	

APPENDIX 6: GLOSSARY

ADMD	After-Diversity Maximum Demand
ADSL	Asymmetric Digital Subscriber Line
AVC	Automatic Voltage Control
BAU	Business as Usual
CDM	Construction (Design and Management) Regulations
CLNR	Customer-Led Network Revolution
DNO	Distribution Network Operator
DNP	Distributor Network Protocol
DSM	Demand Side Management (includes DSR, GSR and EES)
DSR	Demand Side Response
DSSE	Distribution System State Estimator
DVSF	Diversified Voltage Sensitivity Factor
EAVC	Enhanced Automatic Voltage Control
EES	Electrical Energy Storage
ESQCR	Electricity Safety, Quality and Continuity Regulations
FAT	Factory Acceptance Testing
FDWH	Flexible Data Warehouse
FDVF	Feeder Diversity Voltage Factor
FPP	Flexible Plug and Play (UKPN LCNF project)
GPRS	General Packet Radio Services
GSR	Generation Side Response
GUS	Grand Unified Scheme (Control Infrastructure)
HV	High Voltage
I/O	Input/Output
ITT	Invitation To Tender
LV	Low Voltage (i.e. below 1,000V line-to-line)
LVN	LV Network
LCNF	Low Carbon Networks Fund
LDC	Load Drop Compensation
NMS	Network Management System
NPADDS	Network Planning and Design Decision Support tool
NPS	Network Product Specifications
OLTC	On-Load Tap-Changer
PV	Photovoltaic
RDC	Remote Distribution Controller
RTTR	Real-Time Thermal Ratings
RTU	Remote Terminal Unit
SAT	Site Acceptance Testing
ToU	Time-of-Use
UKPN	UK Power Networks
VCC	Volt-VAr Control
VEEEG	Validation, Extension, Extrapolation, Enhancement and Generalisation
VSF	Voltage sensitivity factor
VPN	Virtual Private Network

Customer-Led Network Revolution

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