A Review and Synthesis of the Outcomes from Low Carbon Networks Fund Projects

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Contents

Executive Summary

Background

The Low Carbon Networks Fund (LCNF) was established by Ofgem in 2009 with an objective *to "help Distribution Network Operators (DNOs) understand how they provide security of supply at value for money and facilitate transition to the low carbon economy"* [1]. The £500m fund operated in a tiered format, funding small scale projects as Tier 1 and running a Tier 2 annual competitive process to fund a smaller number of large projects. By 31st March 2015, forty Tier 1 projects and twenty-three Tier 2 projects had been approved with project budgets totalling £29.5m and £220.3m respectively. The LCNF governance arrangements [1] state that projects should focus on the trialling of: new equipment (more specifically, that unproven in GB), novel arrangements or applications of existing equipment, novel operational practices, or novel commercial arrangements. Tier 1 projects were specifically required to have a Technology Readiness Level (TRL) between 5 and 8. TRL 9 was excluded, as projects with this TRL were thought to be too low risk and offer limited scope for new knowledge to be generated. TRLs were not specifically mentioned in the governance arrangements for Tier 2 projects; however, it was stated that projects should be neither at the R&D stage nor involve the widespread deployment of proven technology or practices. Instead, the methods being trialled should be "untested at the scale and circumstance in which the DNO wishes it to be deployed and that consequently new learning will result from the project" [1].

The requirement that learning gained from projects could be disseminated was a key feature of the LCNF. In the application process for Tier 1 and Tier 2 projects, DNOs were asked to demonstrate that the projects would generate knowledge which did not exist before the proposed trials. Tier 2 bids also had to provide a robust methodology to capture and disseminate the learning [1]. As a mechanism to reward well managed Tier 2 projects, a Successful Delivery Reward was available up to the value of the DNO's 10% contribution of a project's costs. The Successful Delivery Reward Criteria (SDRC) were required to be linked to project milestones, target outputs and learning dissemination activities.

The motivation for the review reported here was a recognition that significant learning and data had been generated from a large volume of project activity but, with so many individual reports published, that it was difficult for outside observers to identify clear messages with respect to the innovations investigated under the programme. Moreover, there was a variation in the way outcomes had been reported, published and disseminated. Evaluation of the findings is essential if lessons are to be learned and the results of such trials are to enable appropriate changes to standard practice in the operation, planning, management and regulation of the electricity system and inform related policies. The evaluation and synthesis of the outcomes is also important in helping to define the scale, scope and focus of future innovation, research and development projects. This review is therefore intended to identify, categorise and synthesise the learning outcomes published by LCNF projects up to December 2015.

Assessment of project outcomes

A register of LCNF projects has been developed that, for each project, categorises both the context of the work and the innovations that were being investigated, i.e. the 'why' and the 'how' of each project. The categories were used to create a 'heat map' of LCNF project activity and from this a set of 'learning topics' was derived as a basis for synthesis of outcomes (Figure 1). The main learning for each is summarised in the following sections.

The reporting of LCNF learning by DNOs contains a strong focus on the diffusion of an innovation into business as usual (BAU). LCNF project close-down reports require DNOs to provide details on project replication (including BAU costs) and planned implementation of the innovation. However, a motivation for a project investigating a particular, potentially beneficial, innovation to be given LCNF support is that its long-term benefits to electricity users are still uncertain. As LCNF projects may be trialling innovations from

TRL 5 upwards, the project is not guaranteed to move the innovation to TRL 9 where it is ready for BAU implementation. The purpose of the LCNF project is to gain knowledge about the innovation and reduce uncertainty about its prospects of ever being a cost-effective TRL 9 innovation and how to get there.

As a consequence of the above, the approach adopted in this review considers whether a project has generated robust evidence on whether the innovation can be considered as a BAU option ready for appropriate deployment when required or whether the innovation has, in fact, insufficient benefit and should not be regarded as a viable option by the DNO. For each synthesis theme, a range of innovations has been identified and assessed in terms of evidence for, or against, BAU according to the scale shown in Figure 2. This approach does not use the BAU score ascribed to the trialled innovations as the basis for judging the 'success' of a project. Judged purely on BAU readiness, projects providing outcomes with scores of -4, -3, +3 or +4 can be regarded as successful in that they have provided robust evidence. However, projects might deliver BAU scores around 0 for two main reasons: trials failed to deliver strong evidence due to inadequate experimental design, unforeseen problems in the LCNF project's implementation or poor dissemination of findings; or the innovation being tested turned out to have unanticipated issues that would require further work to resolve. The learning from this latter category, in particular, is still useful – the issues would probably not have been revealed without the LNCF work, the TRL may nevertheless have been advanced and important learning can be gained on whether additional work to further advance the TRL, ultimately to TRL 9, is justified relative to the benefits the innovation promises to bring.

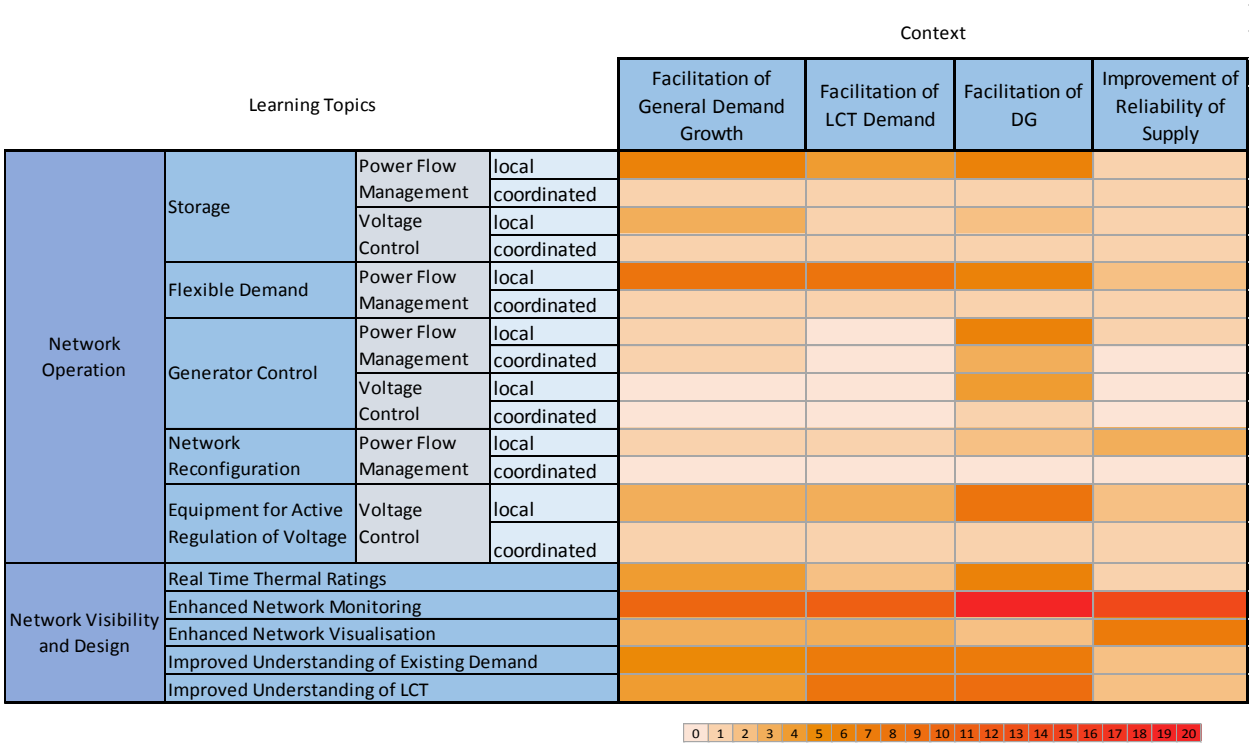


Figure 1: Heat Map of LCNF Project Activity

The detailed BAU assessments of the main report are summarised for each of the synthesis themes presented in the following section. A median value and range of scores is provided for each innovation to represent the overall BAU position across all the DNOs. The median BAU score is represented by the location on the BAU scale of the coloured bar. The width of the coloured bar represents the relative amount of project activity in this area and the width of the high-low line indicates the range of scores across the relevant projects.

Strong Evidence Against		Indications Against		Inconclusive	Indications For		Strong Evidence For	
-4	-3	-2	-1	0	1	2	3	4

Figure 2: BAU Scoring Chart

Summary of Learning Synthesis and BAU potential

Battery Energy Storage

LCNF projects have produced a significant body of field experience in the procurement, installation and operation of battery storage for power flow management and voltage control on distribution networks. In general, projects have focussed on two types of storage deployment: large scale batteries (>500kW) that are connected to the primary network and distributed smaller scale storage connected at secondary substations or low voltage (LV) feeders. Although technical proof of concept for peak shaving and reactive power import/export has been demonstrated, many technical challenges have been encountered and recorded in the published learning outputs. Commercial, regulatory and legal barriers have been identified; however, solutions to these barriers are yet to be found. The overall picture for battery storage is one of early exploration and identification of barriers that future work must overcome. Batteries (particularly at large scale) appear unlikely to be widely deployed by DNOs without significant reduction in costs and major efforts to clarify the regulatory and legal aspects. The BAU summary is shown in Table 1 below.

Key Learning:

- Technical proof of concept for power flow management and voltage support applications has been demonstrated by multiple projects.
- The technology is still evolving and field experience has been valuable to uncover the difference between theoretical (modelled) and practical operation characteristics.
- Round trip efficiencies as low as 40% have been observed[1].
- Auxiliary power requirements are a significant factor in reduced efficiency performance.
- Charge/discharge characteristics can vary significantly between units of the same technology.
- Accurately measuring and modelling State of Charge has been problematic in practice and is a major challenge for battery life cycle management.
- Where business case analysis is provided by the projects, costs are currently unjustifiable when only DNO network reinforcement deferral is considered; where multiple hypothetical revenue streams are considered, a positive cost-benefit analysis (CBA) is sometimes achieved.
- Large scale battery storage may be an attractive, flexible solution for DNOs if it can be contracted from 3rd parties; however, a viable business case for 3rd parties remains to be demonstrated.
- Small scale distributed storage may become an attractive solution as technical understanding and control methods develop; however, costs are still prohibitive.

Recommendations:

- Given the reported technical, commercial and regulatory challenges with large-scale storage, DNO innovation efforts should not focus on DNO owned and deployed storage, but on supporting the necessary industry developments and commercial model evolution that allow DNOs to tender, on a technology neutral basis, for flexibility services.
- An exception to the above is smaller-scale distributed storage deployed at secondary substations and LV feeders. Further evidence on the value such storage can provide through voltage support,

[1] Although a direct comparison with expected (manufacturer rated) efficiency is not provided in most cases, the general trend is that although battery charge/discharge efficiencies are claimed to be upwards of 80%, the full round-trip efficiency including parasitic power requirements is often significantly less.

peak shifting and phase balancing functionality – combined with tracking of market developments and cost reductions – is needed to allow robust business case analysis.

- Understanding the most appropriate approaches to the control of smaller scale distributed storage (e.g. real-time versus forecast and schedule, or local versus coordinated) should remain a research and innovation priority.

Learning Topic	Innovation	BAU Score (-4 to 4)
Storage for Power Flow Management and Voltage Control	Large Scale Batteries	
	Distributed Small Scale Batteries	

Table 1: Summary of BAU Scores for Storage Innovations

Flexible Demand

The LCNF projects have tested several methods of harnessing demand flexibility for power flow management purposes. Control methods have either been scheduled indirect control (tariffs) or have been event-driven direct control where the demand resource has been dispatched with respect to a single, locally measured constraint (e.g. substation load). Efforts have primarily focussed on the technical and commercial aspects of controlling Industrial and Commercial (I&C) demand. Time of Use tariffs for residential customers and control of new low carbon technology (LCT) load such as electric vehicle charging and heat pumps have also been tested. The BAU summary is shown in Table 2 below.

Key Learning:

- Voltage reduction to achieve general demand reduction has been demonstrated successfully; all DNOs should consider the application of this as a BAU option.
- The C2C project's solution for managed flexible connection of I&C demand should also be considered as a BAU option by all DNOs.
- On-demand dispatch of I&C demand (call-off contracts) has been successfully trialled and should be progressed to a BAU option by all DNOs. Challenges remain to reduce uncertainty around reliability, CBA and acceptable risk for post-fault flexible demand.
- Residential Time of Use tariffs have shown limited potential in the LCNF trials. Although some peak reduction was achieved, the solution was deemed unlikely to provide sufficient benefit to avoid network reinforcement.
- Residential direct demand control trials also achieved limited network benefits.
- As trialled in LCNF projects, residential flexible demand is unlikely to be a solution deployed by DNOs although if rolled out by suppliers, DNOs may derive some benefit.
- LCT direct control has shown good potential; however, trials are for relatively small numbers and the technology is at early stages of development.

Recommendations:

- Further collaborative efforts to establish best practice in voltage reduction and the potential for offering frequency response should be undertaken by the DNO community.
- Further dissemination of the C2C method should be undertaken with all DNOs formally assessing its potential for their network areas.
- Collaborative efforts to establish industry best practice for I&C flexible demand should be undertaken addressing:
    - the geographical nature of flexible demand requirement;

- the best methods of contracting flexible demand; and
- improved understanding of reliability and appropriate planning methods.

- Data-sets from the LCNF I&C trials should be consolidated in order to provide further insight to appropriate methods of accounting for flexible demand within industry security of supply standards and to identify further work required to improve the understanding of risk for post-fault flexible demand.
- New methods of harnessing the potential of residential demand response should remain an innovation priority in parallel with efforts to establish the necessary frameworks with suppliers to enable DNOs to access this resource.
- LCT direct control should remain an innovation priority, developing the technical and commercial understanding of such solutions, in addition to the development of appropriate planning tools in readiness for significant LCT adoption.

Learning Topic	Innovation	BAU Score (-4 to 4)
Flexible Demand for Power Flow Management	Voltage Optimisation	
	Industrial & Commercial Managed Connections	
	Industrial & Commercial Call Off Contracts	
	Residential Time of Use Tariffs	
	Residential Appliance Control	
	Residential LCT Control	
	Community Engagement	

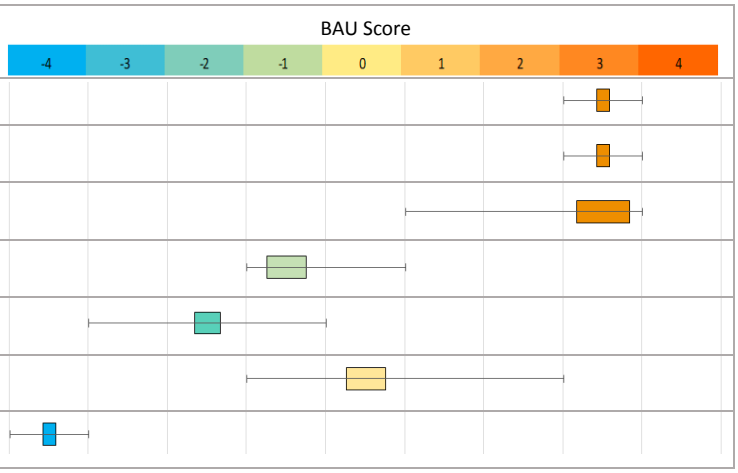


Table 2: Summary of BAU Scores for Flexible Demand Innovations

Generator Control

Several LCNF projects have effectively demonstrated the benefits of controlling Distributed Generation (DG, i.e. generation embedded within a distribution network). For the most part, these projects closely replicate the Active Network Management (ANM) solution developed by Scottish and Southern Energy Power Distribution under previous innovation funding, although some additional learning has been generated. The Scottish Power Energy Networks project, Accelerating Renewable Connections (ARC), has yet to close and report fully at the time of writing but has the potential to provide learning on new approaches to ANM that include the impact of local demand behind the critical network export constraint. The BAU summary is shown in Table 3 below.

Key Learning:

- Active Network Management for DG connections should be a BAU option for all DNOs.
- The ANM solution has matured; extensive experience has been garnered and shared.
- DNOs have collaborated to produce an ANM best practice guide.
- Templates of commercial documents[2], planning tools and stakeholder engagement and information tools are now well-developed.

[2] Standardised connection agreements, offer letters, terms and conditions, etc.

- The deployments are predominately stand-alone, local solutions based on measurement of pre-identified constraints, with control of generator output based on a Last in First Out commercial model.
- Pro-rata commercial models were trialled successfully and found to offer improved efficiency in maximising connected generation for specific constraint scenarios.
- Pro-rata was found to be suitable for reverse power flow constraints on grid substations; however, it was deemed technically unsuitable for more complicated situations with multiple constraints.
- Contracting with an aggregator for temporary installation of DG, i.e. seasonal deployment such as of diesel generators during the winter, was found to be technically and commercially unviable.
- The understanding of DG contribution to security of supply has been progressed and new data produced that can inform review of ETR130/131 guidance documents and the current review of Engineering Recommendation P2/6.

Recommendations:

- Detailed analysis of the ANM route to BAU and the role of innovation funding at different stages in the process should be undertaken to inform future innovation project direction and policy for the development of other promising technologies.
- ANM solutions that account for and utilise load 'behind the meter' should be an ongoing innovation focus (depending on results from SPEN's ARC project).
- Alternative technical and commercial solutions and the transition to more coordinated, integrated wide area control should remain an innovation priority.
- There is the opportunity for a collaborative effort that utilises all relevant data from numerous LCNF projects (and other DG projects) to provide further insight into DG contribution to security of supply and to update ETR 130/131.

Learning Topic	Innovation	BAU Score (-4 to 4)
Generator Control for Power Flow Management and Voltage Control	Actively Managed DG Connections	
	Seasonal Generation Deployment	

Table 3: Summary of BAU Scores for Generator Control Innovations

Network Reconfiguration

Although tested by comparatively few LCNF projects, learning has been produced regarding methods to alter the network's operating configuration on a permanent or dynamic basis for power flow management purposes. Methods include creating a 33kV ring by closing the normally open point between two feeders, enhanced control of 11kV switches to dynamically transfer load between primary substations and new automation and protection for LV networks. The BAU summary is shown in Table 4 below.

Key Learning:

- In the cases assessed, interconnection at 33kV has been shown to have insufficient benefit to justify deployment.
- Interconnection between 11kV substations has been shown to have significant potential for cost-effective release of network capacity by the Flexible Network Connections project; however, some contrary evidence is provided by the FALCON project.
- Justification for interconnection and automation at LV has yet to be proven; however, significant projects in this area are yet to close and report fully.

- ‘Smart Fuse’ technology for LV networks has shown significant potential and should be considered as a BAU option.

Recommendations:

- Further work on 11kV interconnection should be carried out to enhance the evidence base and confirm the potential of the solution as a BAU option for all DNOs.

Learning Topic	Innovation	BAU Score (-4 to 4)
Network Configuration for Power Flow Management and Protection	33kV Interconnection	
	11kV Interconnection	
	LV Interconnection	
	LV Smart Fuse	

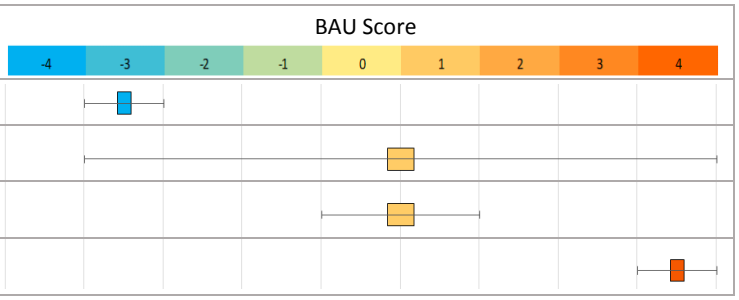


Table 4: Summary of BAU Scores for Network Reconfiguration Innovations

Equipment for Active Regulation of Voltage

Transformers, voltage regulators and reactive power compensation equipment are well understood technologies in the context of voltage management of power systems. Several LCNF projects have pursued innovation in the way these technologies are deployed on distribution networks in Britain and in the methods of control utilised. Trials have tested the benefits of enhanced automatic voltage control at primary substations, on-load tap change (OLTC) transformers for secondary substations, voltage regulators, capacitors and distribution static synchronous compensators (D-STATCOM). The BAU summary is shown in Table 5 below.

Key Learning:

- Voltage reduction at primary substations has been demonstrated as an effective method of releasing ‘headroom’ capacity that might also, depending on the nature of the load, potentially reduce energy consumption. This should be considered as a BAU option by all DNOs (revision of grid code stipulations may be required).
- Suggested approaches to voltage reduction vary between DNOs:
  - a permanent reduction of 1%;
  - seasonal reduction up to 3%;
  - local control by Load Drop Compensation up to 3%;
  - coordinated control by a wide area control scheme.
- Dynamic control of voltage reduction has been noted to open the possibility of DNO provision of balancing services to National Grid.
- Enhancing automatic voltage control (AVC) functionality for primary substations via relay upgrade, additional control capability and enabling remote configuration, allows improved local control and is a key enabler for area coordinated voltage control.
- Deployment of secondary substation OLTC has been shown to release significant ‘legroom’; however, there is debate on whether a positive CBA can be built versus LV re-cabling[3].

[3] Although some additional footprint requirements were noted in the trial installations, secondary OLTC transformer sizes have not been highlighted as a barrier to deployment by these projects.

- High voltage (HV) Automatic Voltage Regulators (AVRs) are a useful enabling technology for flexible networks.
- D-STATCOM devices have demonstrated effective voltage control; however, issues are reported around costs and practical aspects of implementation.
- Results indicate the coordinated control of multiple voltage management devices across the network enables full value (increased network capacity) to be realised; however, this has only been partially demonstrated and is deemed difficult and too complex at present.
- The deployment of many controllable devices at all voltage levels requires coordination via area control schemes. The previous statement on complexity and necessity of such schemes, plus outputs on voltage management strategy by projects, indicate that although some of this voltage control equipment may be deployed in isolated, case-specific circumstances, limited additional control will be deployed beyond primary substations in the foreseeable future.

Recommendations:

- There is an opportunity for further knowledge sharing and collaborative efforts to establish best practice for voltage reduction. This should include further detailed technical work on associated issues including trends in the voltage dependency of loads, circulating currents and relay hunting.
- Additional to any upgrades required to deliver voltage reduction, enhanced voltage control functionality for primary substations should be considered as a standard deployment as a key enabler for future voltage control strategies.
- Innovation work should focus on proving/improving the business case of secondary substation OLTC against LV reinforcement.
- There is an opportunity for further knowledge sharing and collaborative efforts to establish best practice for HV Automatic Voltage Regulator applications.
- Further innovation in respect of voltage regulation should focus on the required coordination and control architectures (boundaries between local and centralised control, and coordinated management of thermal and voltage constraints) rather than being approached solely from an equipment testing perspective.

Learning Topic	Innovation	BAU Score (-4 to 4)
Equipment for Active Regulation of Voltage	Voltage Reduction	
	Primary Substation Enhanced AVC	
	Secondary substation OLTC	
	Voltage Regulators	
	Switched Capacitors	
	D-STATCOM	

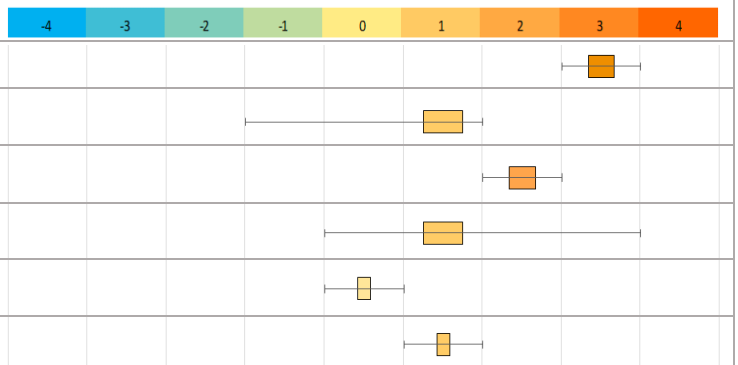


Table 5: Summary of BAU Scores for Equipment for Active Regulation of Voltage

Real Time Thermal Ratings

The LCNF projects have produced a significant amount of learning on methods for real-time thermal ratings of overhead lines, underground cables and transformers at all voltage levels. There appears to be a strong body of evidence that real-time thermal ratings (RTTR) offer significant benefit for overhead lines at 33kV and above, particularly in conjunction with ANM of DG. However, the project findings are not consistent in

this, with one project ruling out the solution due to perceived risks around sheltering[4]. The evidence suggests RTTR for 11kV overhead lines is more challenging and further work would be required to make the solution sufficiently reliable. RTTR for primary substation transformers has also demonstrated the ability to unlock significant capacity. For other types of asset RTTR the learning is at an early stage and further work is required to improve the evidence base. The BAU summary is shown in Table 6 below.

Key Learning:

- Results reveal that, in general, static ratings are not always as conservative as had been commonly assumed and RTTR can be less than the static rating more often than expected by the existing standards.
- There are conflicting statements on the need for dynamic ratings; deployments of monitoring to calculate enhanced static ratings have been proposed as sufficient.
- RTTR for 132kV and 33kV overhead lines is well tested by LCNF projects.
- Average uplift for 33kV OHL is in the order of 10-15%.
- There are conflicting conclusions on the issue of sheltering for 33kV OHL RTTR.
- 33kV OHL RTTR or enhanced ratings can unlock capacity and should move to BAU, particularly with ANM for DG connections.
- RTTR for primary transformers was shown to enable 30% increase in peak loading above nameplate by modelling in one project; however, trials were limited to 10% by other asset capacity issues. Other projects had less conclusive results; however, in general, results suggest an uplift of 10% is achievable.
- RTTR for 11kV OHL, underground cables and distribution transformers requires further work – some benefits have been observed, but issues such as rapid variability and improved thermal modelling need to be addressed.

Recommendations:

- There is an opportunity for further knowledge sharing and collaboration to establish industry best practice on 33kV OHL RTTR.
- Learning and experiences from across the projects on RTTR for 11kV OHL, underground cables and transformers should be further reviewed and consolidated, with a view to establishing the most appropriate further innovation work for RTTR or bespoke enhanced ratings of these assets.

Learning Topic	Innovation	BAU Score (-4 to 4)
Real Time Thermal Ratings (RTTR)	33kV Overhead Line RTTR	
	11kV Overhead Line RTTR	
	Underground Cable RTTR	
	Underground Cable RTTR	

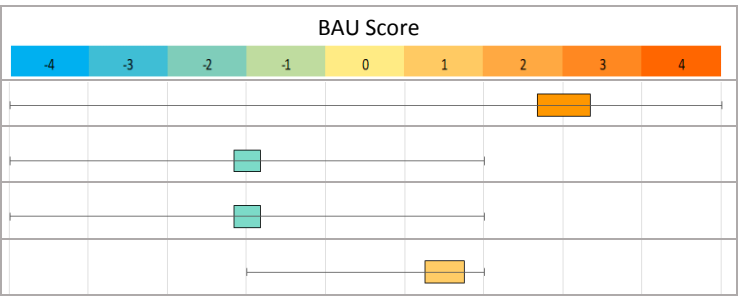


Table 6: Summary of BAU Scores for Real Time Thermal Ratings Innovations

Enhanced Network Monitoring

The most prominent activity amongst the LCNF projects has been the deployment of network monitoring to 11kV feeders, secondary substations and LV feeders, motivated as an enabler for other innovation (e.g. visibility for more active network operation) or to reduce uncertainty associated with LCT deployment (e.g.

[4] The effect of local geography sheltering sections of the line from wind and hence creating 'hot-spots' that are not accounted for in the particular RTTR methodology used.

visibility for improved planning). All DNOs have been active in this area and have developed their capability to extend enhanced network monitoring across their networks. Several early LCNF projects specifically addressed the technical challenge of monitoring lower voltage networks as their core objective. The consensus from the LCNF learning outcomes is that enhanced monitoring is an option that will be deployed as requirements arise. The BAU summary is shown in Table 7 below.

Key Learning:

- The ability to deploy enhanced monitoring across the network should now be a BAU process for all DNOs.
- There is no strong business case for enhanced permanent monitoring alone; it is an enabler for other innovation or to remove uncertainty caused by LCT penetration.
- Detailed recommendations on network monitoring requirements and best practice have been made by several projects.
- In respect of strategies for staged deployment of network monitoring and optimal use of network data, approaches and recommendations vary between DNOs.
- A variety of communication network solutions have been trialled with results displaying a range of performance and reliability across the different technologies.

Recommendations:

- Collaborative efforts should be undertaken by the DNO community to consolidate the various findings and establish industry best practice for network monitoring technology and communication network solutions.
- Collaborative efforts should be undertaken by the DNO community to consolidate strategy recommendations and establish best practice on network monitoring strategy.

Learning Topic	Innovation	BAU Score (-4 to 4)
Enhanced Network Monitoring	11kV Feeder Monitoring	
	Secondary Substation Monitoring	
	LV Feeder Monitoring	
	Utilising Smart Meter Data	

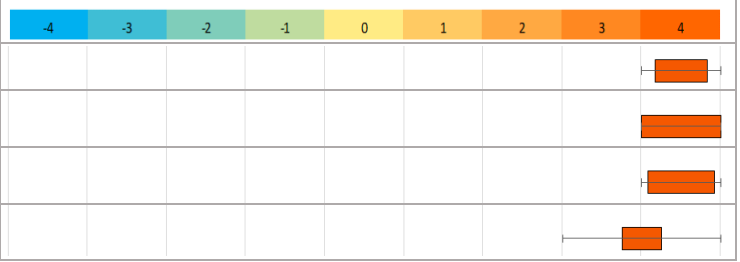


Table 7: Summary of BAU Scores for Enhanced Network Monitoring Innovations

Enhanced Network Visualisation

Data acquisition in LCNF projects has been undertaken in many cases as a one-off exercise in order to support testing and validation of new solutions. In other cases, the gathering, processing, presentation and utilisation of data is a core feature of the innovation. Where the data is brought back to a centralised location (control room) new tools and systems have been developed that allow the analysis and visualisation of the data. These may be linked to the existing Network Management System or may be stand alone. Work in this area centres around building capability to build detailed network models of 11kV and LV network areas that can then be populated by data, either in near real-time for distribution state estimation that in turn enables control decisions, or retrospectively for longer term planning studies. The BAU summary is shown in Table 8 below.

Key Learning:

- Capabilities for detailed modelling of distribution networks, down to the customer point of connection, have been developed and many different load flow packages with varying functionality have been utilised.

- Detailed modelling has encountered many challenges including: accuracy of asset records, translation of asset records into suitable data formats, integration of new tools into existing systems and databases, and availability of suitable commercial packages for new analysis requirements.
- Distribution System State Estimation (DSSE) has been tested – further work is required to improve functionality and improve accuracy.
- New data analytics tools have been developed that integrate monitoring data with existing GIS and asset management systems.

Recommendations:

- Collective experience on distribution network modelling tools should be established with a comparative analysis of functionality and data and integration challenges.
- DSSE is a requirement for area control systems and should remain an innovation priority area.
- There is opportunity for further knowledge sharing to fully demonstrate prototype visualisation tools and communicate potential applications and benefits.

Learning Topic	Innovation	BAU Score (-4 -3 -2 -1 0 1 2 3 4)
Enhanced Network Visualisation	11kV and LV Network Modelling	
	Data Analytics Tools	
	Distribution System State Estimation	

Table 8: Summary of BAU Scores for Enhanced Network Visualisation Innovations

Improved Understanding of Existing Demand

Many projects have gathered data in order to update the current industry understanding of demand for use in investment planning. By gaining access to large quantities of smart meter data, either by partnering with early electricity supply company deployments or by deploying project specific metering to represent expected future smart meter functionality, projects have explored the ways in which smart meter data can be used by DNOs. The majority of activity has been on updating existing planning methods with new design assumptions ('after diversity maximum demand' – ADMD – values or profiles), rather than developing entirely new planning methods based on more advanced analysis of load. The BAU summary is shown in Table 9 below.

Key Learning:

- New ADMD values, customer categorisations and DEBUT[5] planning profiles are now available along with enhanced LV substation load profiling; however, methods and recommendations vary between projects.
- The improved understanding of load from several projects indicates that additional capacity can be released under existing planning methods and policy; however, results vary between projects.
- Although an updated understanding of load has obvious value, for the most part the new load profiles follow expected patterns and look very similar to legacy profiles. More advanced, probabilistic methods of modelling and forecasting load have had limited attention – advanced planning techniques are likely to be required but are in very early stages of development.
- The focus of LCNF project activity indicates that a main application DNOs see for smart meter data is the periodic updating of load profiles for current planning and design methods.

[5] DEBUT is planning software used by a number of DNOs.

- Several projects have deployed 'End Point Monitoring' to simulate access to smart meter data for operational purposes.
- There appears to be a risk that either DNO value from more dynamic access to smart meter data is proven but not permitted by current policy/functionality and hence duplicate metering is required; or DNO value from more dynamic access to smart meter data is not properly explored as DNOs believe current policy/functionality will not enable it to be realised anyway.

Recommendations:

- There is an opportunity to bring together the data sets and new insights related to load and planning in order to establish new industry standards and ensure all DNOs are able to fully exploit existing network capacity.
- Whilst current planning and design methods can be usefully updated by LCNF insights, the use of initial LCNF work on new planning and design methods should be an innovation priority going forward, assessing the benefits of utilising extensive quantities of data for more complex probabilistic planning and design, in place of deterministic methods.
- The use of 'End Point' data for operational purposes should remain an innovation priority in order to establish any benefits and demonstrate either a business case for DNO owned metering additional to smart meters or to highlight the need for augmented DNO access to smart meters.

Learning Topic	Innovation	BAU Score (-4 -3 -2 -1 0 1 2 3 4)
Improved Understanding of Existing Demand	New Planning Assumptions for Substation Load	
	New Planning Assumptions for Residential Load	

Table 9: Summary of BAU Scores for Innovations on Improved Understanding of Existing Demand

Improved Understanding of LCT

Projects have investigated the characteristics of LCT loads such as Electric Vehicles and Heat Pumps, as well as investigating the characteristics of residential PV generation. This includes developing ways to represent this new load and generation that exists 'behind the meter' within existing planning tools and also developing new planning methods for LCT. The BAU summary is shown in Table 10 below.

Key Learning:

- New ADMD values and planning profiles are now available for EV, heat pumps and solar PV.
- Findings on LCT ADMD and planning profiles are from relatively small sample sets – further work to characterise LCT demand for robust planning will be necessary as deployments increase.
- A consensus appears to be building on residential PV output diversity and updates to planning policy that can release immediate capacity.

Recommendations:

- Insight into LCT demand and impact is limited by lack of practical experience due to current low penetration levels. Continually updating understanding of LCT and incorporating it into planning and design methods should remain a priority for the DNOs.
- Further collaboration should take place to establish a consensus on appropriate PV connection policy that should become BAU for the sector in the immediate future.

Learning Topic	Innovation	BAU Score -4 -3 -2 -1 0 1 2 3 4
Improved Understanding of LCT	New Planning Assumptions for Electric Vehicles and Heat Pumps	
	New Planning Assumptions for Residential PV	

Table 10: Summary of BAU Scores for Innovations on Improved Understanding of LCT

Conclusions

The learning from LCNF projects undoubtedly leaves the DNOs in Britain with a better understanding of the challenges and potential solutions for networks during the low carbon transition.

A challenge arising from the quantity of learning generated is its accessibility to other DNOs and the wider stakeholder community. Successful consolidation of the learning is essential to advance viable solutions and undertake further work in the most efficient manner. This review and synthesis project accomplishes a first stage of this process. For full value to be taken from the LCNF learning, we would recommend that detailed work to consolidate, contrast and compare learning across projects is undertaken for targeted topics in order to fully establish remaining gaps in knowledge and to inform further innovation work. For each of the synthesis themes identified we have provided a set of detailed recommendations to this effect.

A key requirement set by Ofgem for the use of LCNF money was that learning should be shared. In reviewing the reports produced by the LCNF projects we have found variation in the quality of evidence reported. There are numerous potential reasons for this; however, in general, we observe a focus on 'successful demonstration', i.e. that a project has demonstrated all the elements that were promised. This is in contrast to a focus on whether a project has generated robust evidence that the innovations have been, can be or should be moved up the scale of TRLs (or, conversely, should be pursued no further). Although mostly positioned as upper TRL demonstrator projects, Tier 2 projects often contained significant amounts of development work. We observe an absence of clear definitions for the TRL of each innovation trialled within a Tier 2 project and the absence of a learning and dissemination methodology that accounts for the range of TRLs, and crucially, allows for learning by failure. Although our assessment of evidence for or against BAU adoption has not been conducted as a judgement of project success, it has been influenced by the way learning has been reported. If a project has not produced evidence of sufficient quality and it is difficult to determine a clear movement on the TRL scale, then evidence on BAU adoption remains highly uncertain. This is a very different end result from where a project has produced good quality learning that still leaves significant uncertainty and need for further work before the innovation can be regarded as a viable BAU option with a TRL of 9.

We believe that rewards for success should recognise the relative risk and uncertainty involved in developing ideas and trialling innovations at different TRLs and should place an appropriate balance of emphasis between: good project management; the quality of evidence produced and conclusions on how a TRL has been progressed; what TRL an innovation has reached; and whether investment is justified in seeking further TRL progress.

Notwithstanding the above comments, our conclusion is that much useful knowledge has been generated by the projects supported by the LCNF. In those terms, the LCNF has been valuable. We believe that it is essential that DNOs continue to consider and evaluate novel technologies and methods that can be applied in planning or operation of their networks and benefit network users and now build on the LCNF learning to develop innovation strategies that are based on a coherent vision of future distribution system operation.

This review has not been concerned with whether the particular regulatory mechanism put in place for the support of innovation has been necessary or appropriate but rather with a consolidation of the learning that has been achieved with respect to the innovations that have been investigated. However, the volume of

research, development and demonstration (R,D&D) activity led by the DNOs under LCNF and the relative lack of it in the years following liberalisation of the electricity supply industry in Britain and before the introduction of LCNF and its predecessor, the Innovation Funding Incentive (IFI), suggest that, without these schemes, established 'business as usual' would have remained unchallenged and the necessary DNO R,D&D to facilitate the Low Carbon Transition is, in our view, likely to have been stagnant at best and non-existent at worst. Compared with the situation before IFI and LCNF, the DNOs are considerably more active in R,D&D and open to innovation. Moreover, we are confident that, collectively, they will now be much better at scoping, managing and reporting R,D&D than they were. Furthermore, the communities from which the DNOs' project partners have been drawn should now be much better equipped to support them. Both the increased level of engagement with R,D&D and improvements in the way the DNOs do it could be regarded as indicative of LCNF being a successful scheme.

As we have found from our review, there are a number of areas in which further R,D&D is required to inform potential innovation. It has not been our intention in this review to assess or comment on whether further regulatory support mechanisms for R,D&D are required to facilitate or encourage this. However, the history of distribution network licensee engagement with R&D before the introduction of specific support mechanisms suggests that they are.

1 Introduction

1.1 Background

Recent research indicates that annual expenditure by distribution network operators (DNOs) on research and development (R&D) was almost £12 million in 1989/90, around the time of liberalisation of the electricity supply industry in Britain [2]. This fell to just £1 million by 2003/4 but, following the introduction of the Innovation Funding Incentive (IFI), recovered to just over £12 million in 2007/8.

In August 2009 Ofgem established the £500m Low Carbon Networks Fund (LCNF) as a financial catalyst for innovation within the electricity and distribution price control arrangements running from 1st April 2010 to 31st March 2015. The stated objective of the LCN Fund was *to help DNOs understand how they provide security of supply at value for money and facilitate transition to the low carbon economy* [1]. The forecast take up of low-carbon technologies (LCT) such as electric vehicles, heat pumps and distributed renewable generation are expected to place a significant burden on distribution networks and innovation in areas such as demand side management, enhanced control and the use of smart meter data is likely to be essential to minimise the cost of facilitating this transition.

The fund operated in a tiered format, funding small scale projects as Tier 1, and running a Tier 2 annual competitive process to fund a smaller number of large 'flagship' projects. The LCNF Governance arrangements [1] state that projects should focus on the trialling of: new equipment (more specifically, that unproven in GB), novel arrangements or applications of existing equipment, novel operational practices, or novel commercial arrangements. Tier 1 projects were specifically required to have a Technology Readiness Level (TRL) between 5 and 8. TRL 9 was excluded, as projects with this TRL were thought to be too low risk and offer limited scope for new knowledge to be generated. TRLs were not specifically mentioned in the governance for Tier 2 projects. However, the requirements for Tier 2 projects stated the projects should be neither at the R&D stage nor involve the widespread deployment of proven technology or practices. Instead, the methods being trialled should be "untested at the scale and circumstance in which the DNO wishes it to be deployed and that consequently new learning will result from the project".

The requirement that learning gained from projects could be disseminated was a key feature of the LCNF. In the application process for Tier 1 and Tier 2 projects, DNOs were asked to demonstrate that the projects would generate knowledge which did not exist before the proposed trials. Tier 2 bids also had to provide a robust methodology to capture and disseminate the learning [1].

In designing the LCNF, Ofgem sought to simulate the risk and reward that innovation offers to unregulated companies. To represent risk, DNOs were required to provide 10% of the total project cost as a mandatory contribution. The other 90% of project costs were recoverable from their customers. As a mechanism to reward well managed Tier 2 projects, a Successful Delivery Reward up to the value of the DNOs 10% contribution was available. At the application stage, Tier 2 projects were obliged to set out Successful Delivery Reward Criteria (SDRC) and on project completion an application for discretionary funding could be made based on compliance with the SDRC. The SDRC were required to be linked to project milestones, target outputs and learning dissemination activities.

By 31st March 2015, forty Tier 1 projects and twenty-three Tier 2 projects had been approved with project budgets totalling £29.5m and £220.3m respectively. The breakdown of projects by DNO is shown in Table 11.

DNO	Projects	Project Budgets £m
Tier 2		
Electricity North West (ENWL)	4	29.1
Northern Powergrid (NPG)	1	31.0
Scottish Power Energy Networks (SPEN)	2	11.0
Scottish and Southern Energy Power Distribution (SSEPD)	4	37.9
UK Power Networks (UKPN)	6	61.0
Wester Power Distribution (WPD)	6	50.2
		220.3
Tier 1		
Electricity North West (ENWL)	8	9.2
Northern Powergrid (NPG)	1	2.9
Scottish Power Energy Networks (SPEN)	6	2.3
Scottish and Southern Energy Power Distribution (SSEPD)	9	5.0
UK Power Networks (UKPN)	4	4.5
Wester Power Distribution (WPD)	13	5.7
		29.5

Table 11: LCNF Approved Project Budgets per DNO

The motivation for the review reported here was a recognition that significant learning and data had been generated from a large volume of project activity. Many individual reports were published making it difficult for outside observers to identify clear messages from the programme as a whole. Moreover, there was variability in the way outcomes had been reported, published and disseminated.

The LCNF is just one of a number of programmes, using distribution customers' money, or using public funds, that have demonstrated or trialled smarter systems for power networks. Evaluation of the findings is essential if lessons are to be learned and the results of such trials are to enable appropriate changes to standard practice in the operation, planning, management and regulation of the electricity system and to inform related policies. HubNet and the UK Energy Research Centre (UKERC), which commissioned this work, believed that the business, research and policy communities would benefit from a categorisation and synthesis of the learning to inform future activities and research.

1.2 Approach and Report Structure

The objective of this review was to identify, categorise and synthesise the learning outcomes published by LCNF projects and has been motivated by the following questions:

- What has motivated LCNF project activity?
- What are the key topics around which investigations have centred and learning has been achieved?
- To what extent are the trialled innovations ready for business as usual (BAU)?
- To what extent has the LCNF been successful in encouraging innovation activity?

In December 2015, Ofgem started a consultation that [3] asked "*to what extent do you consider that the LCN Fund has succeeded?*" Respondents highlighted that LCNF success is often defined in terms of the diffusion of the trialled innovation into BAU [4, 5] and suggested that the nature of the Successful Delivery Reward Criteria and the expectation that business plans for the RIIO (Revenue = Incentives + Innovation +

Outputs) ED1 price control period[6] would include savings from smart grid innovation are possible reasons for this interpretation. It was also noted that the transfer of trialled innovations into BAU is only likely to be fully apparent over the course of the ED1 price control period, rather than from interpretation of LCNF project outputs themselves. Detailed analysis of the LCNF as a regulatory mechanism for the support of innovation has been conducted elsewhere [6] and is not included within the main scope of this report; however, based on the understanding gained during the process of this review, some reflections on the LCNF as a programme are provided in Section 11.

The stated objective of the LCNF was, *"to help Distribution Network Operators (DNOs) understand how they provide security of supply at value for money and facilitate transition to the low carbon economy" [1]*. Achieving such an understanding requires projects that generate appropriate learning to inform on the technical viability and cost-effectiveness of innovative technology solutions or business processes. The approach taken in this report is to review and synthesise the learning produced by projects and assess the evidence generated in terms of its contribution to a robust business case for, or against, adopting the innovation as BAU.

Based on the above rationale, the project involved the following tasks:

1. Develop a suitable framework to identify and categorize innovation and learning outcomes.
2. Identify suitable themes for synthesis of learning outcomes.
3. Develop a suitable method to assess the quality of evidence published by each LCNF project with respect to prospects for Business As Usual adoption of an innovation.
4. Produce a review and synthesis of learning outcomes.

As many LCNF projects were still underway during the period of this review and the evidence base represented something of a moving target, a cut-off date of 31st December 2015 was applied for review of closed projects. Although projects that were not closed prior to this date have been mentioned where appropriate, any subsequently published close down reports or learning material have not been considered. Similarly, although an analysis of transfer to Business As Usual would benefit from a detailed review of RIIO ED1 submissions, this has not been included in the scope of this work. Where appropriate, DNO references to ED1 have been included; however, no formal review of ED1 submissions has taken place here.

Section 2 describes the work undertaken with respect to tasks 1-3 and the synthesis of learning outcomes (task 4) is described in Sections 3 to 9. The main findings are set out in Section 10, reflections on LCNF reporting in Section 11, and conclusions in Section 12.

[6] The RIIO-ED1 price control set the outputs that the electricity DNOs need to deliver for their consumers and the associated revenues they are allowed to collect for the eight-year period from 1 April 2015 to 31 March 2023. For further information, see https://www.ofgem.gov.uk/network-regulation-riio-model/riio-ed1-price-control

2 Project Categorisation and Analysis

All Tier 2 and Tier 1 projects were examined to establish the availability and format of learning outcomes, which was found to vary significantly between projects. Some projects have dedicated websites with comprehensive project libraries whereas others rely on the Ofgem[7] or ENA[8] websites to publish outputs and may be limited to project management update reports and close down reports. (Tier 1 projects primarily take the latter approach). Learning may be explicitly published as an industry recommendation, a learning paper or data set. Alternatively, learning may be embedded within progress reports. Following this initial review, a process of project categorization was carried out.

2.1 Categorising Projects

The high level descriptors for all 64 Tier 1 and 2 projects were reviewed in terms of stated overall objectives, the innovations being investigated and intended outcomes. The LCNF Project submission documents to Ofgem tend to describe a high level problem, or general focus, that defines the type of activities undertaken. Subsequently a set of category headings were derived and arranged under the groupings: Context, and Learning Topic.

2.1.1 Context

The context, or motivation, of a project is a description of ***why*** a project has been undertaken. A number of particular contexts within which innovations were sought, or business areas in which it was felt that improvements could be made were identified:

- Facilitation of **general demand growth**
- Facilitation of **new low carbon demand:** electric vehicles (EV) and heat pumps (HP)
- Facilitation of **distributed generation (DG)**: wind, hydroelectricity, photovoltaics (PV) and combined heat and power (CHP)
- Improvement of **reliability of supply**

2.1.2 Learning Topics

The Learning Topics are the innovative interventions proposed by projects. These are the ***what*** or ***how*** of the project and are grouped under the following high level headings:

Network Visibility and Design: capturing and using data to understand the network state better, provide better information for investment planning or to support another innovation.

Network Operation: innovation in control, operation of existing assets and the deployment and use of new assets for the purposes of Power Flow Management (PFM), Voltage Control (VC) and Protection.

Learning in the above areas of Network Visibility, Design and Operation also often includes related learning on: updated policies and standards, new commercial arrangements, and new system operation arrangements (interacting with the Transmission System Operator or devolving control to 3rd parties).

2.2 Analysis of Project Activity

A spreadsheet register of projects was created that captured the basic project details for all LCNF registered projects (Figure 3). Further analysis of project activities then revealed a number of common themes under the above headings.

[7] https://www.ofgem.gov.uk/electricity/distribution-networks/network-innovation/low-carbon-networks-fund
[8] http://www.smarternetworks.org/

Learning Topic

Context

Title	DNO	Budget (£m)	Tier	Start Date	End Date	Progress	Close Down Report Issued	Voltage Level
Trial Evaluation of Domestic Demand Management Solutions (DDMS)	SSEPD	0.28	Tier1	Sep 10	Aug 12	100%	Yes	LV
Distribution Network Visibility	UKPN	0.25	Tier1	Sep 10	Nov 13	100%	Yes	HV/LV
Interconnection of WPD and NGC SCADA systems	WPD	0.078	Tier1	Nov 10	Dec 12	100%	Yes	EHV/HV/LV
The 'Bidoyng' Smart Fuse	ENWL	0.44	Tier1	Dec 10	Dec 14	100%	Yes	LV
Customer Led Network Revolution	NPG	31	Tier2	Dec 10	Dec 14	100%	yes	HV/LV
Low Carbon London	UKPN	28	Tier2	Dec 10	Dec 14	100%	yes	HV/LV
LV Network Templates	WPD	7.8	Tier2	Dec 10	Jul 14	100%	yes	LV

Figure 3: Register of LCNF Projects

Innovations for Network Operation

- **Storage**
- **Flexible Demand**
- **Generator Control**
- **Network Configuration**
- **Equipment for Active Regulation of Voltage**

Each of the themes under this heading can be grouped under their core technical functions of Power Flow Management and Voltage Control. However, it is also possible to synthesise the learning according to the type of technology trialled, the kind of control used and associated developments in Commercial Arrangements and Policies and Standards.

Innovations for Network Visibility and Design

- **Real Time Thermal Ratings**
- **Enhanced Network Monitoring**
- **Enhanced Network Visualisation**
- **Enhanced Understanding of Existing Demand**
- **Enhanced Understanding of LCT**

Activity in this area concerns obtaining and utilising network data to establish the network's parameters and state and the influences of parties or equipment connected to the network. Project activity on Real Time Thermal Ratings, fundamentally concerned with determining what the safe limit to thermal loading of a network branch is at a given moment in time, is substantial and has therefore been treated as a unique synthesis theme. Based on the activities of the reviewed projects, the term 'network data' refers to electrical measurements representing the voltage and current at different points across the distribution network, smart meter data, and electrical measurements of the devices behind a customer's meter that impact the level of demand on (or export to) the Low Voltage network.

Figure 4 represents a 'heat map' of the learning topics and project context with activity intensity as measured by the number of projects that involve the particular combination of context and theme[9].

[9] No attempt was made to produce a 'heat map' of activity intensity as represented by project expenditure. This was because many projects involved more than one motivation and more than one innovation and, based on published information, it was generally not possible to determine how much money was being invested in each.

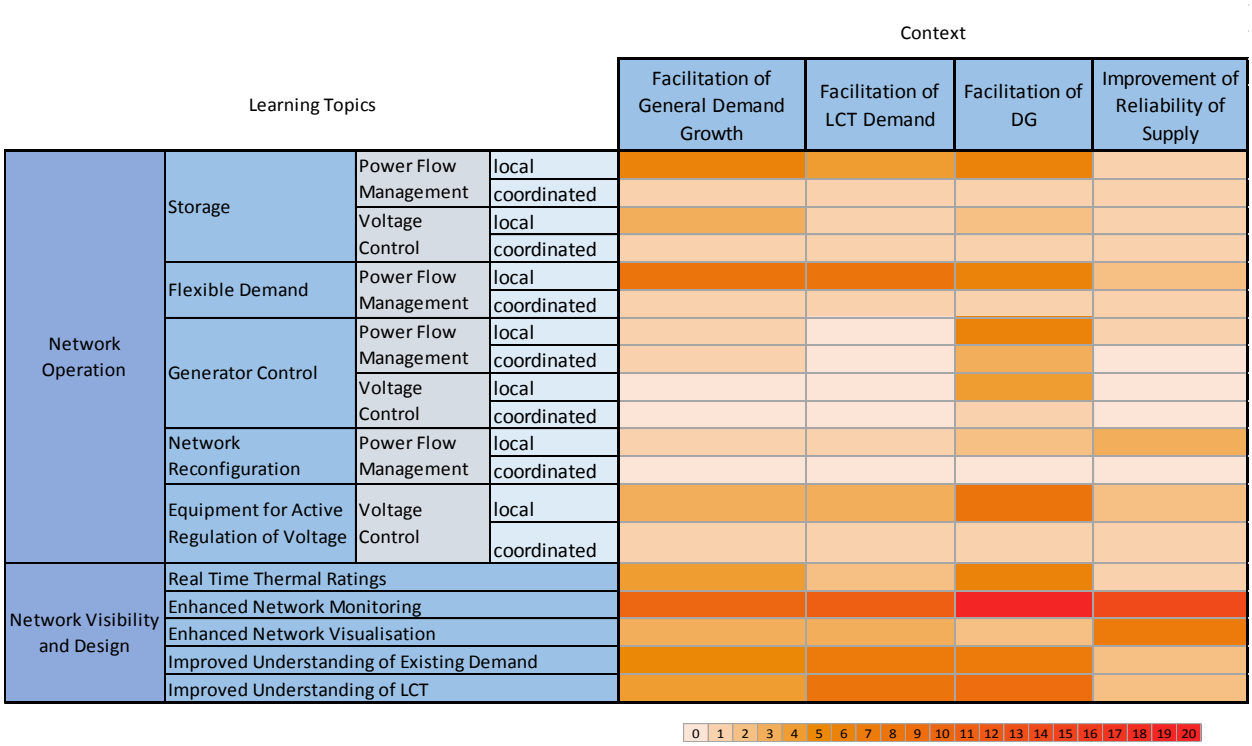


Figure 4: Heat Map of LCNF Project Activity

Figure 5 and Figure 6 provide additional insight into the numbers of projects that addressed each context and learning. The most prevalent context is the facilitation of DG connection to distribution networks. Traditional DNO priorities of facilitating general demand growth and improving reliability of supply receive similar amounts of attention to each other. Facilitation of Low Carbon demand was the least prevalent context.

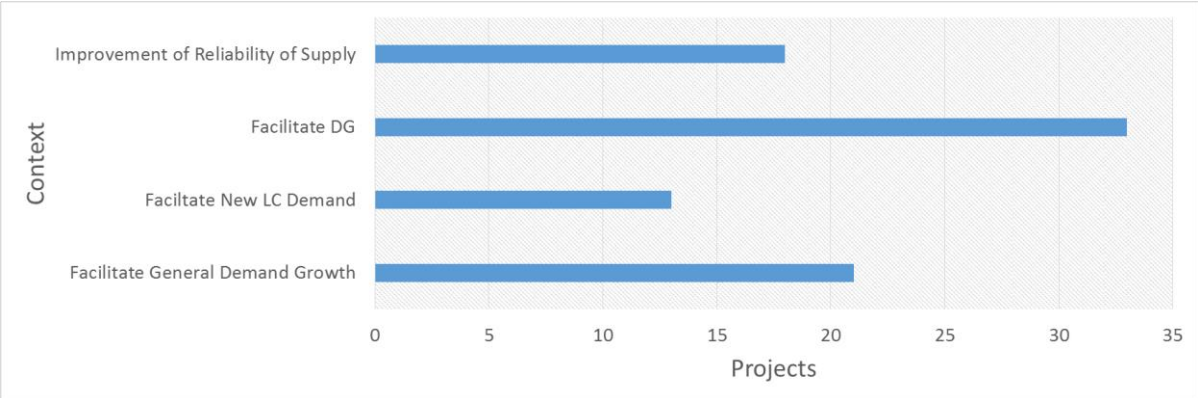


Figure 5: Occurrence of Contexts in Projects

In Figure 6, Network Monitoring is clearly the dominant area of innovation activity. This implies that DNOs perceived a need to progress from the existing method of operating distribution networks which relies on established design assumptions and requires very little visibility of the state of the network to having extended observability of the network and its real-time state relative to limits. In addition, many innovations, not least for control of the network, rely on some form of network monitoring. Localised Power

Flow Management using Storage and Flexible Demand, and localised Voltage Control using Equipment for Active Regulation of Voltage are the most prevalent innovations related to network operation. Methods of coordinated control have been addressed by only a few projects (although it is noted that these involved some large, significant deployments).

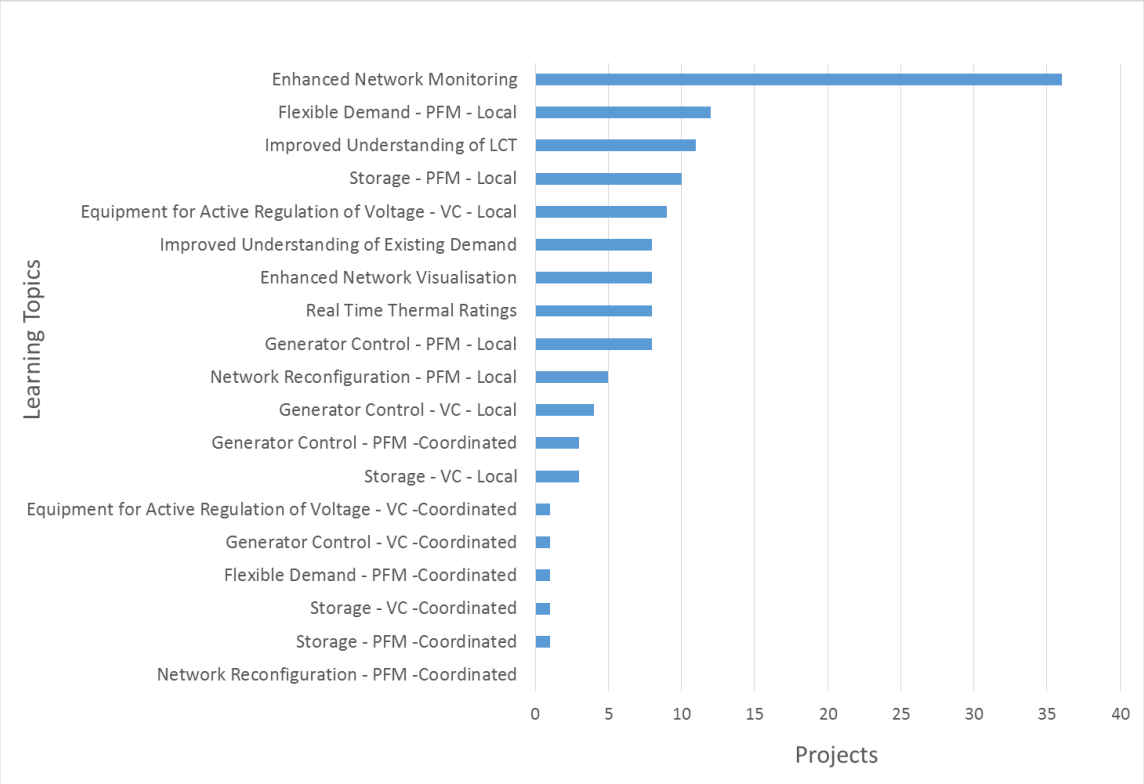


Figure 6: Occurrence of Learning Topics in Projects

2.3 Assessing Progress to Business as Usual

The reporting of LCNF learning by DNOs contains a strong focus on the diffusion of an innovation into business as usual (BAU). LCNF project close-down reports require DNOs to provide details on project replication (including anticipated BAU costs) and planned implementation of the innovation. However, a motivation for a project investigating a particular, potentially beneficial, innovation to be given LCNF support is that its long-term net benefits to electricity users are still uncertain. As LCNF projects may be trialling innovations from TRL 5 upwards, the project is not guaranteed to move the innovation to TRL 9 where it is ready for BAU implementation. Furthermore, even an innovation that has reached TRL 9 and has a positive cost-benefit might not be adopted in the short-term because the background conditions do not yet require it. An example of this is some technology or method to accommodate large numbers of electric vehicles (EVs) being charged on the network but where the current number of EVs is too small to require it. The purpose of the LCNF project is to gain knowledge about the innovation and reduce uncertainty about its prospects of ever being a cost-effective TRL 9 innovation and how to get there. The overall impression that 'successful' LCNF projects are those that progress innovation into BAU has also been noted in responses to a consultation started by Ofgem in December 2015 [4, 5, 7].

The approach adopted in this review considers whether a project has generated robust evidence on whether the innovation can be considered as a BAU option ready for appropriate deployment when required or whether the innovation has, in fact, insufficient benefit and should not be regarded as a viable option by the DNO. For each synthesis theme, the identified range of innovations has been assessed in terms of evidence for, or against, BAU according to the scale shown in Figure 7.

Strong Evidence Against	-4	The DNO reports a strong conclusion that the innovation is ineffective or the costs are excessive relative to the benefit. The DNO explicitly states no intention to revisit the trialled innovation.
	-3	The DNO concludes that the costs of the innovation are excessive relative to the benefit. The DNO does not explicitly rule out revisiting the trialled innovation or notes that future technical or commercial developments may lead the innovation to be re-examined.
Indications Against	-2	The results as presented in DNO reports appear to indicate that the costs of the innovation are excessive relative to the benefit; however, some uncertainty remains around the benefits and costs.
	-1	The results as presented in DNO reports appear to indicate some possible benefits though, insofar as the DNO has conducted a cost-benefit analysis, costs seem to outweigh the benefits; major uncertainty still exists around the potential benefits and expected costs.
Inconclusive	0	The results as presented in DNO reports lack clear evidence for or against BAU adoption or the DNO reaches no clear conclusions on the innovation. However, the work conducted may provide some lessons for further research requirements to provide suitable evidence.
Indications For	1	The results as presented in DNO reports appear to indicate the potential for a reasonable level of benefit which, insofar as the DNO has conducted a cost-benefit analysis, are expected to exceed costs; however, major uncertainty still exists around the potential benefits and expected costs.
	2	The results as presented in DNO reports indicate a good level of benefit relative to expected costs; however, some uncertainty remains around the benefits and costs, some work is still to be done to make the innovation ready for deployment or the conditions under which the innovation would be justified are yet to arise.
Strong Evidence For	3	The DNO concludes that the solution is technically and commercially ready for deployment and benefits clearly justify the costs. However, some further work is required on developing deployment capability and integrating the innovation into existing systems and processes. The DNO indicates some deployment towards the end of ED1.
	4	The DNO concludes that the solution is technically and commercially ready for deployment and the benefits clearly justify the costs. Few barriers are noted. The DNO has indicated significant deployment in ED1.

Figure 7: Framework for Assessing Business as Usual

The approach used does not use the BAU score ascribed to the trialled innovations as the basis for judging the 'success' of a project. Judged purely on BAU readiness, projects providing outcomes with scores of -4, -3, +3 or +4 can be regarded as successful in that they have provided robust evidence. However, projects might deliver BAU scores around 0 for one or both of two main reasons:

1. trials failed to deliver strong evidence due to inadequate experimental design, unforeseen problems in the LCNF project's implementation or poor dissemination of findings; or
2. the innovation being tested turned out to have unanticipated issues that would require further work to resolve.

The learning from the latter category, in particular, is still useful – the issues would probably not have been revealed without the LNCF work, the TRL may nevertheless have been advanced and important learning can be gained on whether additional work to further advance the TRL, ultimately to TRL 9, is justified relative to the benefits the innovation promises to bring.

3 Synthesis of Learning on Battery Energy Storage

The heat map analysis identifies a high level of activity around the use of storage for power flow management and voltage management and also in the commercial and policy aspects of DNO deployed storage. The storage technologies tested are all electrical battery storage.

The review considered:

- What storage technologies have been deployed?
- What levels of efficiency and reliability have been observed?
- What applications of storage have been tested and what level of value to the network was demonstrated?
- What has been learnt on the commercial, regulatory and legal aspects of DNO deployed storage?
- How close to BAU are the different storage technologies?

The storage projects reviewed in this section are shown in Table 12.

Title	DNO	Budget (£m)	Tier	Start Date	End Date
Demonstrating the benefits of short-term discharge energy storage on an 11kV distribution network	UKPN	0.23	1	Jun-10	Jan-14
Smarter Network Storage	UKPN	13.2	2	Dec-12	Dec-16
1MW Battery, Shetland	SSEPD	1.0	1	Sep-10	Dec-13
Orkney Energy Storage Park	SSEPD	0.25	1	Oct-11	Oct-12
New Thames Valley Vision	SSEPD	22.8	2	Dec-11	Mar-17
LV Network Connected Energy Storage	SSEPD	0.3	1	Jan-12	Mar-14
Trial of Orkney Energy Storage Park	SSEPD	1.5	1	Jun-12	Mar-15
Customer Led Network Revolution	NPG	31.0	2	Dec-10	Dec-14
FALCON	WPD	12.4	2	Dec-11	Sep-15
BRISTOL	WPD	2.2	2	Dec-11	Jan-16

Table 12: LCNF Projects featuring Storage

3.1 Project Details

The projects listed in Table 12 are reviewed in the following sections. An overview of the main features of these projects is also provided in Table 38 in Appendix A.

3.1.1 UK POWER NETWORKS

3.1.1.1 Overview of Projects

UKPN undertook a Tier 1 technical proof of concept project titled Demonstrating the Benefits of Short-Term Discharge Energy Storage on an 11kV Distribution Network [8]. A Lithium-Ion, 600kW/200kWh battery was deployed and tested for local operation of Voltage Control and Power Flow Management functionality. The battery energy storage system (BESS) was connected at the normally open point of connection of two 11kV feeders in a network area containing a 2.5MW wind farm connection. Technical proof of concept of peak shaving and voltage control was demonstrated, as was the ability to decrease curtailment of the wind generator. The project focus was primarily on technical applications rather than building a business case; however, the project reports replication costs as an estimated £1.9m capital with £42.5k annual maintenance costs.

A Tier 2 project, Smarter Network Storage (SNS), is trialling a large scale battery installation (6MW/10MWh) at a primary substation that is approaching full capacity. The project aims to explore multiple benefit and revenue streams in order to improve the business case for storage. The commercial arrangements have been established via a contract with a supplier for route to market for imported/exported electricity and a contract with an aggregator for route to market for balancing services. At the time of this review, SNS was still in the integration and testing stage and was yet to publish full results and learning outcomes. A detailed interim report on the implications/experience of deploying BESS as a network asset is available [9].

A detailed discussion and set of recommendations have been produced on the regulatory and legal framework [10]. The issues (bullet list) and recommendations (numbered list) set out are:

- The default treatment of storage as a subset of generation creates uncertainty, hence:
    1. Define storage as a distinct activity.
    2. Include storage within the licensing framework.
    3. Inclusion of an exemption for small-scale installations.
    4. Develop a transition plan.
- Unbundling requirements add uncertainty, and needs separation of licensed network and non-network activities for energy storage under DNO-led models.
- Application and operation of storage assets is affected by the need to ensure that competition in generation and supply is not distorted, hence:
    5. Promote contestability in provision of storage.
    6. Ensure non-distortion of competition.
    7. Confirm interpretation of application of *de minimis* business restrictions under proposed arrangements.
    8. Develop arrangements for treatment of storage investment within price controls.
- Treatment of import as end consumption under climate change, renewable and low carbon supplier charges increase operating costs for storage operators.
    9. Clarify definition of end-user consumption to exclude injections into storage.
- Distribution charging methodologies could be inconsistent and impact the charges for storage owners
    10. Reconsider whether current charging methodologies are appropriate for storage.
- Optimised connections and distribution charging agreements for storage (and other flexibility) are needed to support wide adoption.
    11. DNOs to continue to develop optimised connection and distribution charging agreements for storage (and other flexibility).
- Categorisation of storage installations into intermittent or non-intermittent tariffs under CDCM connections impact the network charges for operators.
    12. Agreed framework for categorising storage installations into intermittent or non-intermittent resources under CDCM connections.
- Reactive power capability of energy storage systems and other power electronics grid interfaced energy resources is not recognised.
    13. Consider appropriate reactive power support mechanisms.

3.1.1.2 Key Learning

The key learning published in the reporting referenced in this section is set out below.

Learning published by the Tier1 demonstration project:

- Testing indicated that auxiliary power requirements were significant and contributed to reduced round-trip efficiencies (observed minimum of 78%).
- Significant downtime issues due to malfunction of electrical and environmental protection systems were also experienced.
- Financial analysis of the project highlighted up to £70/day lost on difference between import/export revenue.
- The project noted that establishing multiple technical benefits and revenue streams is essential to move towards a commercially viable model, and that industry-wide work was required on the regulatory framework for DNO owned and operated storage. These issues provided the motivation for the subsequent Tier 2 project Smarter Network Storage.

Learning published by SNS:

- Housing storage of MW scale is a challenge. There is no clear best option between a building-based or containerised solution.
- Deploying storage is more rapid than network reinforcement. The storage facility was installed and ready to support the network within approximately 12 months.
- Persistent technical issues encountered were: the presence of high frequency circulating currents, errors in the communications between inverters and battery controllers, and errors between the batteries and BMS units themselves as a result of EMC interference and susceptibility across the different systems.
- For building-based installations, earthing for high frequency currents is a key design issue.
- Electro-magnetic compatibility testing should also be prioritised before deployment.

3.1.1.3 BAU Assessment

<u>Large Scale Batteries</u>

UKPN projects have focussed on larger scale (>500kw) batteries; trialling Power Flow Management and Voltage Control with a local control scheme. The early Tier 1 trial demonstrated technical benefits but did not consider the wider business case. The Smarter Network Storage trials have highlighted many commercial, regulatory and legal barriers. Costs appear extremely high and technical issues have been numerous. Although still yet to publish full findings, it seems likely that the Smarter Network Storage project will produce evidence that large scale batteries can be installed and operated successfully for some technical benefit; however, further technical trials may be needed to reduce uncertainty and build confidence. Given the cost of the project and the published list of issues and recommendations regarding the regulatory and legal framework; the indications are that many hurdles remain to be overcome to build a positive business case for DNO owned and operated storage at this scale. **BAU Score: -1.**

3.1.2 SSEPD

SSEPD have undertaken deployment of large scale battery storage in both Shetland and Orkney. They also have the New Thames Valley Vision (NTVV) project which includes a deployment of 25 small scale storage units on the low voltage network. As a pre-cursor to the NTVV project, a Tier 1 project undertook a small deployment of LV connected storage.

The Shetland project initially deployed a 1MW Sodium Sulphur (NAS) battery; however, this was replaced with a 1MW/3MWh Valve Regulated Lead Acid battery due to safety concerns. The battery has been integrated to the Northern Isles New Energy Solutions (NINES) project and is controlled by the NINES Active Network Management (ANM) system for system operational purposes on the islanded Shetland network. As a non LCNF project, NINES learning outcomes are not reported or published in the same manner and a full review has not been possible for this work; however, the initial Tier 1 project on the battery testing has been reported [11].

The Orkney project aimed to explore the possibility of contracting network services from a storage provider and was split into two phases. Phase 1 [12] focussed on creating the new commercial contracts required and identifying an Energy Storage Provider (ESP) to partner before moving to deployment in Phase 2 [13]. The objective of the project was to explore the viability of an ESP providing a contracted service for constraint management whilst also being free to pursue any other viable revenue streams. The contract was based on daily availability periods and weighted to times of year when constraints were likely to be most prevalent.

A 2MW/500kWh Lithium Ion BESS was integrated with the existing ANM scheme managing generation constraints on the island. This meant that when it indicated availability it could be dispatched by the ANM scheme as an alternative to generator curtailment. When unavailable (either by pursuing alternative revenue or for technical reasons) the BESS was managed as any other generator connection in that its import/export could be curtailed based on the constrained state of the network and its position in the ANM priority queue.

Although the DNO did not have a capital budget for battery purchase, the original project budget included £982k for Contract Billing – i.e. payment to the ESP during the project lifespan.

The Tier 1 project, Low Voltage Connected Batteries [14], was a technical proof of concept that trialled three single phase 25kVA/25kWh BESS in a Low Carbon Housing Estate containing PV and EV installations. The technical applications of real power dispatch for peak shaving and voltage manipulation, and reactive power dispatch for voltage manipulation, were tested successfully.

The New Thames Valley Vision project is deploying 25 BESS on low voltage networks around the Bracknell area [15]. The project is still in progress so published learning outcomes are limited at the time of this review. The units are modular but the tested configuration is a three phase connection of a 36 kVA Power Electronics Unit and 37.5kWh of battery storage. The units are to be controlled in a coordinated fashion based on load forecasting and modelling techniques developed in other strands of the project. The objective is to improve LV network thermal and voltage conditions, enabling LCT penetration via phase balancing, peak shaving and voltage manipulation. Commercially, the units are a DNO asset employed for network operation. Commentary on any regulatory and legal barriers along with a cost benefit analysis (CBA) for deploying storage versus conventional solutions should be expected from this project. The project budget indicates approximately £1.5m for BESS deployment, hence current storage costs are likely to be a barrier as per other project findings.

3.1.2.1 Key Learning

The key learning published in the reporting referenced in this section is set out below.

Learning from the Shetland project:

- Results for testing of the lead acid battery indicate that the technical ability to provide three 1MW hour long discharges during system peak has been proven
- Testing has shown a 75% full round trip efficiency, and approximate replication costs are quoted as £960k.

Learning from the Orkney project:

- The main outcome from this project was that the ESP only billed £270k during the project and did not pursue any other revenue streams. The stated reason was that to do so was ‘un-economic’ for this particular battery deployment.

- A putative business case was modelled by consultants and demonstrated a positive net revenue could be achieved if several significant assumptions were made on improved revenue and reduced costs.

Learning from the Low Voltage Connected Batteries project:

- The project noted that reactive power dispatch had minimal effect due to the highly resistive nature of the LV network.
- Efficiency was observed as 80-88% for static schedules and 68% - 72% for dynamic operation (set points).
- A simple cost analysis observed that with capital cost of the BESS units at £65,000 each and making some assumptions on lifecycle costs, the total cost of the storage solution would be in the order of 2.5 times the cost of an equivalent cable overlay.

3.1.2.2 BAU Assessment

Large Scale Batteries

The Northern Isles projects trialled larger scale batteries for Power Flow Management with local control and produced an evidence set that indicates operation within ANM for constrained wind is technically feasible. However the results indicate that the commercial proposition for a 3rd party to provide this service is not attractive. **BAU Score: -1**.

Small Scale Batteries

Distributed, small scale batteries have been trialled in a Tier 1 project and are under trial in the NTVV project at the time of this review. The Tier 1 project trialled both Power Flow Management and Voltage Control under local control. Learning on the coordinated operation of small scale storage for Power Flow Management and Voltage Control at LV, along with detailed examination of the business case for this solution versus asset upgrades, is expected from NTVV and would present a valuable addition to the knowledge base. However, for this review, the BAU assessment is made on the Tier 1 project findings. **BAU Score: -1.**

3.1.3 NORTHERN POWERGRID

Northern Powergrid deployed six BESS units of varying scale as part of their Customer Led Network Revolution project (CLNR) [16]. The units were tested both in local mode and within an area control scheme.

A trial of large scale batteries deployed a 2,500kVA/5,000kWh BESS connected at the 6kV busbar of a 23MVA primary substation in order to offload (peak shave) the primary transformer and incoming EHV feeders. Reactive power capabilities were also tested for voltage support and loss reduction.

The trial conducted specific experiments related to power flow management (PFM) and voltage control. For power flow management, the approach taken was to test the field performance of the BESS unit to allow validated modelling of the network with and without BESS and then to model the benefit of the BESS in increasing the N-1 capacity of the substation for future LCT connection scenarios [17]. For the trial a virtual maximum current rating for the transformer was used for the BESS set point. A breach of this value triggered BESS discharge. The voltage control experiment incorporated the BESS into the coordinated area control of CLNR's Grand Unified Scheme (GUS) [18]. The published trial data is for a one day demonstration of the area control scheme coordinating the BESS and Automatic Voltage Control (AVC) settings of the primary transformer. In the trial, responding to the system state estimator flagging an over voltage violation in the downstream network, the area control requests a reduction in target voltage from the primary AVC. AVC target voltage range was limited artificially, forcing the area control to call for a reactive power service from the BESS. The BESS absorbs reactive power, reducing voltage to the target level.

In a trial of distributed small scale storage, two 100kVA/200kWh BESS were installed at secondary substations and three 50kVA/100kWh ESS were installed on LV feeders and tested for PFM and voltage support applications [16].

A trial of local PFM involved a 100kVA/200kWh BESS responding to a transformer thermal limit and pre-set SOC limits [19]. Trial results from one day's operation were published. To test coordinated operation, 100KVa and 50KVA units were incorporated into the area control scheme described previously [20]. Trial results from one day's operation are published. In response to a simulated thermal constraint on a known OHL weak point, the area control calculated a required real power absorption from the combined EES resource and dispatched accordingly.

In a further trial, a 50KVA unit was installed and tested on an LV feeder with known high PV penetration [21]. Operation was in local voltage control mode. The voltage control method is based on local measurements and pre calculated voltage sensitivity factors. Published results are for one day of trial. Strict voltage limits (1.0425 pu and 1.025 pu) were applied to test BESS operation.

The technical results from CLNR demonstrate that large and small scale BESS can be deployed successfully at substations and feeders across the HV and LV distribution networks. Peak shaving and voltage control functionality in both local and coordinated mode have been demonstrated under the limited conditions of the trial scenarios. The benefit to network operation has been assessed by modelling extrapolation that assess LCT hosting capacity. Using BESS for power flow management can increase LCT hosting capacity, however, the test networks had a large base LCT hosting capacity so the need for BESS deployment is unclear from this trial. The trials demonstrated a basic scenario of BESS operated in coordination with other voltage control equipment.

Commercial arrangements were not explored in detail by CLNR and analysis of the business case for electrical storage was not a feature of these trials. The practical experiences of procurement, installation, operation and maintenance of BESS have been published. Practical limitations have been highlighted relating to size and noise of the units. In addition the project concluded that existing state-of-charge algorithms are unreliable and that battery ageing and lifespan is not well understood. It was noted that storage should be deployed at lower voltages in order to maximise the realisable benefit to the network – i.e. contributing to upgrade deferral of both a local secondary substation and the area primary substation.

The final position reached by the project with respect to storage was that the preferred deployment model was via a 3rd party provider who (it is thought) can unlock additional value chains and faces fewer regulatory hurdles. CLNR concludes storage should be considered as effectively a flexibility resource that would be a tendered/contracted for in the same way and face the same CBA as a flexible demand service [22].

3.1.3.1 Key Learning

The key learning published in the reporting referenced in this section is set out below.

Large scale BESS:

- Performance:
  - Round-trip Efficiency (excluding parasitic losses) was found to be 83.2%.
  - Average Parasitic Load was measured as 29.5 kW.
  - Round-trip efficiency including parasitic losses, assuming one charge/discharge cycle per day, was found to be 69.0%.
- Power flow management:
  - The BESS could not respond to all thermal excursions due to insufficient State of Charge (SOC).

    - Major differences were observed between measured SOC (obtained from battery terminal voltage measurement) and calculated SOC.
    - Modelling indicated that in the case of air source heat pumps (ASHP) and EVs, the additional headroom provided by this BESS could accommodate an extra 497 and 1591 units respectively (baseline of 7453 ASHP and 20171 EV).
- Voltage Control:
    - Voltage change due to importing real/ reactive power is greater than that of exporting real or reactive power.
    - Reactive power is more effective for controlling voltage even in rural HV networks.
    - In an local voltage control mode of a primary busbar, which neglects the voltage at the end of HV feeders, the numbers of LCTs that can be accommodated is limited by the thermal rating of the transformer.
    - The coordinated use of BESS and AVC can reduce tap operations. Initial investigation indicates that doubling the capacity of the energy storage can result in a 5% reduction in tap change operations.

Small scale BESS:

- Performance:
    - Round Trip Efficiency (excluding parasitic losses) was found to be 86.4% for 100kVA batteries and 83.6 % for 50kVA batteries.
    - Average Parasitic Load was measured as 2.50 kW for 100kVA batteries and 1.77kW for 50kVA batteries.
    - Round Trip Efficiency including parasitic losses, assuming one charge/discharge cycle per day, was found to be 56.3% for 100kVA batteries and 41.2% for 50kVA batteries.
- Local PFM:
    - The results demonstrated that the BESS resolved the majority of thermal excursions.
    - Analysis indicated that using measured terminal battery voltage to calculate SOC in the real control environment introduced errors and ESS behaviour deviated from expected modelled behaviour.
    - Modelling shows that the network can accommodate very high penetrations of EV, HP and PV without BESS. Extrapolation indicates that adding BESS increases the hosting capacity; however, given the base case, the value of this is not clear. Additional hosting capacity is loosely proportional to the additional ESS capacity.
- Coordinated PFM:
    - The results demonstrate the BESS alleviating the majority of excursions; however, as the state estimation only samples in 10-minute periods, some excursions are not dealt with.
    - Trial results were not as fully effective as simulated results due to the SOC calculation issue.
- Voltage Control:
    - Trial results show that real and reactive power import and export manages to maintain voltage within the artificial limits for the majority of the day long trial period.
    - Some differences exist between real and simulated results, these are attributed to SOC modelling issues.
    - Modelling indicates that huge penetrations of LCT can be accommodated on this network without battery support. Extrapolation indicates that BESS can slightly increase hosting capacity. It is concluded that voltage is primarily influenced by the transformer voltage rather than network loading.

3.1.3.2 BAU Assessment

CLNR project evidence does not support a strong BAU conclusion either way for both large scale and small scale BESS because commercial, regulatory and legal aspects were not examined. Technical proof of concept has been achieved, and evidence suggest successful operation; however, the results do not allow strong conclusions on the level of benefit that can be achieved. **BAU Score: 1.**

3.1.4 WESTERN POWER DISTRIBUTION

WPD have deployed LV scale storage in the FALCON project and domestic/SME scale storage in the BRISTOL project. Results from BRISTOL were still to be fully published at the time of this review.

As part of a suite of network interventions trialled in FALCON, five BESS (50kW/100kWh sodium-nickel) were deployed at secondary substations on a single 11kV feeder [23]. This work was primarily a technical trial. A CBA for deploying storage versus conventional solutions was not found. Project budget indicates approximately £1.7m for BESS deployment.

The units were tested in local mode for peak shaving at their connected secondary substation and in a coordinated mode for peak shaving at the area primary substation. The functionality was demonstrated effectively. However, practical experiences highlighted issues around charge and discharge characteristics that varied between units, complexities in accurately measuring and modelling battery SOC, re-calibration procedures, and battery life-cycle management. These issues with availability and energy level uncertainty hindered most effective use of the BESS.

Understanding the available energy in the control room is key to effectively managing the batteries on the Network. This creates a challenge and further research and work is necessary on these systems in order for them to be considered as a reliable source of energy on the UK grid system [23](page 63).

3.1.4.1 Key Learning

The key learning published in the reporting referenced in this section is set out below.

Small scale storage:

- Repeatable, effective peak-shaving has been demonstrated.
- The trialled method of operation would only activate BESS during a few weeks of the year (peak load periods) leaving them redundant for the remaining time.
- Good understanding of peak size and duration (as it varies throughout the year) along with accurate understanding of true SOC levels is required for effective peak-shaving at individual substations.
- These requirements are amplified for coordinated use for peak-shaving at 11kV and issues around managing SOC and battery life-cycle management are exacerbated.
- Audible noise was also a concern with the equipment and its locations. Work with the manufacturer led to modified inductors being fitted to the converters which reduced audible noise

3.1.4.2 BAU Assessment

<u>Small Scale Batteries</u>

The FALCON project evidence for small scale batteries does not support a strong BAU conclusion. Commercial, regulatory and legal aspects were not examined. Trials have demonstrated some potential network benefits through peak shaving; however, they have also revealed several significant technical issues that require further investigation and improved understanding. **BAU Score: -1.**

3.2 Discussion

The LCNF projects provide a significant body of field experience in the procurement, installation and operation of battery storage for distribution networks. Although technical proof of concept for power flow management and voltage control functionality has been demonstrated, many technical challenges have been encountered and recorded in the published learning outputs. Commercial, regulatory and legal barriers have been well scoped; however, solutions to these barriers are yet to be found. The overall picture for battery storage is one of early exploration and identification of barriers that future work must overcome. Batteries (particularly at large scale) appear unlikely to be deployed by DNOs without significant reduction in costs and major efforts to clarify the regulatory and legal aspects. In retrospect, it is also worth asking how much of this learning could have been established without the massive capital cost of physically deploying large scale storage in the field.

In general, projects have either focussed on two models of storage deployment:

- Large sale storage (>500kW) that is connected at the higher voltage levels. Projects trialling this technology addressed the technical benefits for Power Flow Management and Voltage Control but often focussed on the commercial, legal and regulatory aspects, and the additional revenue streams required to build a positive business case.
- Distributed smaller scale storage connected at secondary substations or LV feeders. Projects trialling this technology focussed primarily on the technical aspects of Power Flow Management and Voltage Control to support network operation and defer asset upgrades.

<u>Applications of storage</u>

The applications of storage are summarised in Table 13 below.

Power Flow Management	Local	UKPN, NPG and SSEPD trialled large (MW) BESS with local control. Proof of concept PFM functionality was verified for peak-shaving at primary substations and for reducing wind generation curtailment on constrained networks. NPG, SSEPD and WPD have trialled distributed, smaller scale BESS connected at LV. Proof of concept PFM functionality for peak shaving of secondary substations was verified.
	Coordinated	NPG and WPD trialled coordinated control of small scale BESS connected at LV. Proof of concept PFM functionality to alleviate constraints on the higher voltage network was verified. SSEPD trials of coordinated LV BESS are yet to be published.
Voltage Control	Local	UKPN trialled voltage control for large scale BESS at 11kV. Proof of concept functionality for voltage control via reactive power import/export was verified. NPG and SSEPD trialled small scale BESS at LV. Proof of concept functionality for voltage control via real power import/export was verified.
	Coordinated	NPG trialled the control of large scale BESS reactive power import/export in coordination with control of primary transformer tap settings. Proof of concept functionality was verified.

Table 13: Summary of Battery Storage Applications

Storage Technologies Deployed

All storage tested in these projects has been battery electrical energy storage. The majority have been Lithium Ion technology.

Levels of efficiency and reliability

Observed efficiency has varied greatly and the effect of parasitic load has been shown to have a significant impact. Measuring and modelling SOC accurately has proved to be a significant challenge. Understanding of battery technology has clearly been advanced by these projects; however, the technical challenges appear to have been greater than anticipated in most cases. Actual behaviour has varied significantly from modelled behaviour.

Commercial, regulatory and legal aspects

The commercial, regulatory and legal issues surrounding DNO deployment of storage have been a significant aspect of these projects. The primary learning output from the LCNF projects has been to drive forward a detailed understanding of these issues and potential solutions rather than to solve them. Although technical benefits have been demonstrated, a clear business case that justifies the current cost of storage has not been demonstrated.

3.3 BAU Overview

The battery energy storage projects reviewed in this section cover a range of products and applications of storage. The BAU assessment described in the preceding sections is mapped against the Learning Topic Categories and is summarised in Figure 8. The overall picture is one of inconclusive evidence, tending towards a case against BAU deployment of storage due to costs, technical challenges and regulatory and legal barriers. The technology does still hold attraction as a controllable source of flexibility (particularly for smaller scale batteries) and further work addressing the challenges could still build a future case for storage deployment.

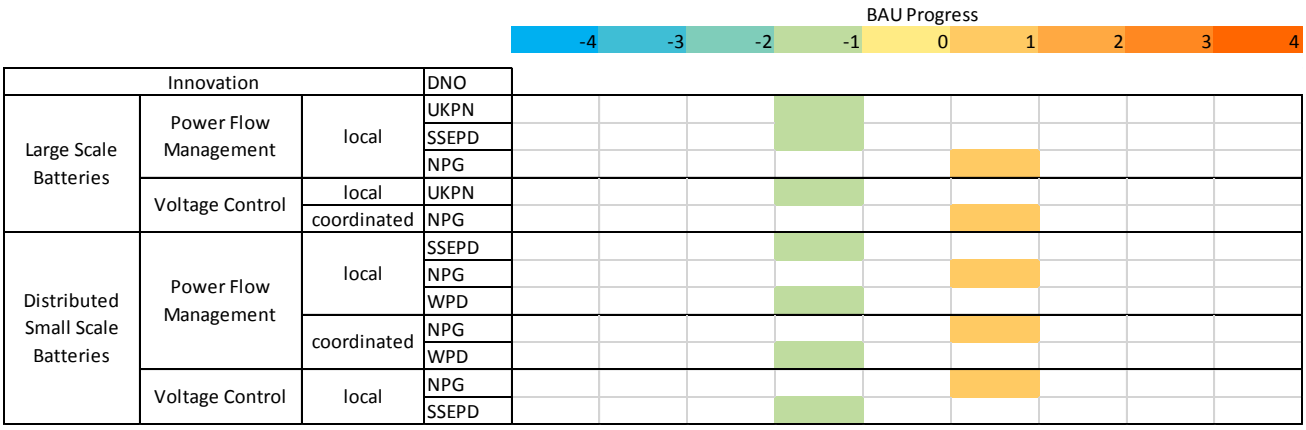


Figure 8: Storage BAU Assessment

3.4 Synthesis of Learning

The synthesis of learning and associated recommendations derived from the review in this section are set out below.

Learning:

- Technical proof of concept for power flow management and voltage support applications has been demonstrated by multiple projects.

- The technology is still evolving and field experience has been valuable to uncover the difference between theoretical (modelled) and practical operation characteristics.
- Round trip efficiencies as low as 40% have been observed[10].
- Auxiliary power requirements are a significant factor in reduced efficiency performance.
- Charge/discharge characteristics can vary significantly between units of the same technology.
- Accurately measuring and modelling State of Charge has been problematic in practice and is a major challenge for battery life cycle management.
- Where business case analysis is provided by the projects, costs are currently unjustifiable when only DNO network reinforcement deferral is considered; where multiple hypothetical revenue streams are considered, a positive cost-benefit analysis (CBA) is sometimes achieved.
- Large scale battery storage may be an attractive, flexible solution for DNOs if it can be contracted from 3rd parties; however, a viable business case for 3rd parties remains to be demonstrated.
- Small scale distributed storage may become an attractive solution as technical understanding and control methods develop; however, costs are still prohibitive.

Recommendations:

- Given the reported technical, commercial and regulatory challenges with large-scale storage, DNO innovation efforts should not focus on DNO owned and deployed storage, but on supporting the necessary industry developments and commercial model evolution that allow DNOs to tender, on a technology neutral basis, for flexibility services.
- An exception to the above is smaller-scale distributed storage deployed at secondary substations and LV feeders. Further evidence on the value such storage can provide through voltage support, peak shifting and phase balancing functionality – combined with tracking of market developments and cost reductions – is needed to allow robust business case analysis.
- Understanding the most appropriate approaches to the control of smaller scale distributed storage (e.g. real-time versus forecast and schedule, or local versus coordinated) should remain a research and innovation priority.

[10] Although a direct comparison with expected (manufacturer rated) efficiency is not provided in most cases, the general trend is that although battery charge/discharge efficiencies are claimed to be upwards of 80%, the full round-trip efficiency including parasitic power requirements is often significantly less.

4 Synthesis of Learning on Flexible Demand

4.1 Introduction

The heat map analysis identifies a high level of activity around the use of Flexible Demand for power flow management and also in the commercial and policy aspects of DNO deployed Flexible Demand.

The review considered:

- What are the variants of Flexible Demand tested?
- For those variants, what has been learned on the level of demand reduction/shift and associated reliability?
- How close to BAU are the tested variants?

The Flexible Demand projects identified for review are shown in Table 14.

Title	DNO	Budget (£m)	Tier	Start Date	End Date
Customer Led Network Revolution	NPG	31.00	2	Dec 10	Dec 14
Low Carbon London	UKPN	28.00	2	Dec 10	Dec 14
Trial Evaluation of Domestic Demand Management Solutions (DDMS)	SSEPD	0.28	1	Sep 10	Aug 12
Honeywell I&C ADR - Demonstrating the Functionality of Automated Demand Response	SSEPD	0.26	1	Jun 11	Aug 12
New Thames Valley Vision	SSEPD	22.80	2	Dec 11	Mar 17
Innovation Squared	SSEPD	4.20	2	Dec 12	Dec 15
FALCON	WPD	12.40	2	Dec 11	Sep 15
BRISTOL	WPD	2.20	2	Dec 11	Jan 16
Community Energy Action	WPD	0.30	1	Oct 12	Mar 15
Capacity to Customers	ENWL	9.10	2	Dec 11	Mar 15
Customer Load Active System Services	ENWL	7.17	2	Dec 12	Sep 15

Table 14: Flexible Demand Projects

4.1.1 Flexible Demand Taxonomy

LCNF projects use a variety of terminology when referring to demand flexibility. Demand Side Management (DSM), Demand Side Response (DSR), Demand Response (DR), Active Demand (AD) are all present in the LCNF reporting literature. The term DSR has been most widely used; however, there is inconsistency in terminology that can often be contradictory and varies between (and even within) projects.

A common approach in the literature [24-27] is to split demand influencing activity into those targeting a general, total demand reduction via energy efficiency type initiatives; and those that seek to shift demand and alter the shape of demand curves. It is mainly within the second category that definitions and terminology become muddied with the type of demand influence varying in the nature of its planning, time horizon, scheduling, method of actuation, reliability, commercial arrangement and so on. For some, DSR is a response to a dynamic signal that may be given at short notice whereas tariff influenced behaviour is separate subset of DSM. For others, DSR is all types of response based on any of: pricing signals, call-off requests for load shed (under contractual arrangements), or automated control.

For this review a new taxonomy has been developed (Figure 9) that adopts and adapts the work of CIGRÉ on Demand Side Integration [28]. We identify the key differentiators (from a distribution networks perspective) as:

- Scheduled flexible demand (forecast driven - based on expected operating conditions) as opposed to event-driven flexible demand (demand resource dynamically deployed in response to intraday operating conditions).
- Indirect control (signal is an incentive or encouragement, such as tariff pricing, to modify electrical load) as opposed to direct control (load can be directly turned on or off by DNO, such as control of electric heating, or DNO sends signal requesting pre-agreed turn down/up of load – i.e. 30 min advance request of I&C load reduction during availability window)

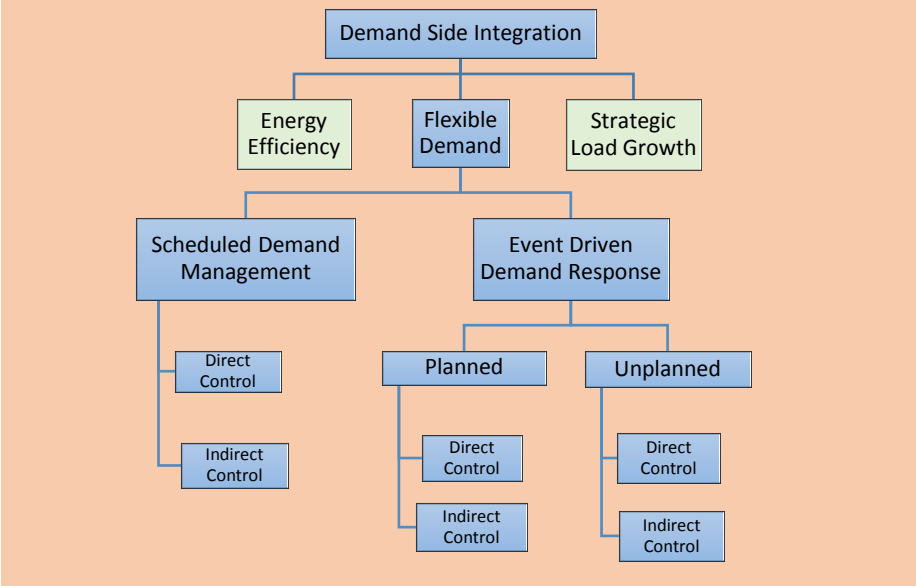


Figure 9: Demand Side Taxonomy

This taxonomy is applied to the identified Flexible Demand LCNF projects and the areas of focus are summarised in Table 15. The majority of projects have taken an event-driven direct control approach.

Title	DNO	Flexible Demand			
		Scheduled		Event-Driven	
		Direct	Indirect	Direct	Indirect
Customer Led Network Revolution	NPG		x	x	
Low Carbon London	UKPN	x	x	x	
Trial Evaluation of Domestic Demand Management Solutions (DDMS)	SSEPD	x			
New Thames Valley Vision	SSEPD			x	
Innovation Squared	SSEPD			x	
Honeywell I&C ADR - Demonstrating the Functionality of Automated Demand Response	SSEPD			x	
Capacity to Customers	ENWL			x	
CLASS	ENWL	x			
FALCON	WPD			x	
BRISTOL	WPD				
Community Energy Action	WPD		x		

Table 15: Flexible Demand Categories

4.2 Project Details

In the following sections, the flexible demand projects are reviewed, summarised and key learning identified. The projects are grouped according to the main categories identified in Table 15 above: Event-Driven Direct Control, Scheduled Direct Control and Scheduled Indirect Control.

4.2.1 NORTHERN POWER GRID

Northern Power Grid's CLNR project undertook a large programme of demand side trials, including both domestic and Industrial and Commercial (I&C) customers.

Event-driven Direct Control

Trials of event-driven, direct control, flexible demand included the dispatch of I&C customer load and dispatch of domestic washing machine and air source heat pump load.

The I&C aspect of the CLNR project focussed on a trial of technical and commercial options for procurement and call-off of flexible demand (load reduction or standby generation) from I&C customers in response to simulated periods of network stress [29]. Both aggregator and direct-contracting models were tested along with alternative signalling methods. Dispatch events were initiated by the CLNR ANM system. Although discussed in terms of general peak reduction, the trials essentially address a post fault use-case from an N-1 security of supply perspective. The trials took place over 25 weeks, included 14 customers, and consisted of 33 events. Event notification was 30 mins prior to the expected response and event duration ranged from 2-4 hours. The contractual arrangements were based on availability and utilisation payments. Analysis was based on an availability of a 4 hour windows for 83 days/year and utilisation of three calls/year for a 4 hour period.

NPG indicate in their published 'Merit Order' that flexible demand ranks highly in the set of solution options [22]. They also provide a ceiling price calculation and indicate a typical maximum price of £17.5/kW/yr, compared to approximately £30/kW/yr for the provision of Short Term Operating Reserve (STOR)[30]. The conclusion is that although the flexible demand pricing analysis compares well to yardstick reinforcement costs at HV, the price signal the DNO could offer may face competition and a framework for sharing flexible demand resources between stakeholders is required. An additional barrier is the geographically specific requirements of the DNO and the associated issues of recruitment and reliability.

CLNR Business Case Example

CLNR provide a typical HV network reinforcement example where the flexible demand requirement is 2MVA to enable a 5 year deferral. Availability required is 4 hours for 83 days/yr and probable utilisation of 2 calls/yr (75% reliability assumed).

Resulting ceiling price = £17.5k/MVA/yr.

Proposed contracts:

1) Daily Rate = £211/MW for 83 days.
2) Availability/Utilisation = £10/MW/h and £591/MW/h with breakeven at 6 calls/yr.

A domestic consumer trial involved 96 British Gas electricity consumers with smart washing machines linked to demand management software platform. The DNO initiated flexible demand events by SMS to British Gas [31] who then initiated the event through a web service provided by a company called GreenCom. Up to a

maximum of 15 interruption events could be called in any one year, between 4-8pm on weekdays. During the trial, 11 events were called between 11/3/14 and 31/3/14. Each of these events lasted for four hours, from 4pm-8pm. Customers were incentivized by £100 of vouchers for participation along with £1000 of free white goods. In the trial report, NPG states that the solution is unlikely to have much impact on distribution network planning; however, perhaps if the technology becomes widespread, it may make some contribution to national system balancing.

An additional domestic consumer trial undertook a demonstration of direct control of domestic heat pumps [31]. A trial of 8 British Gas domestic consumers with 2.7kW ASHP and 300 or 500 litre thermal store linked to a demand management software platform. Events were initiated by SMS to British Gas. Up to a maximum of 15 interruption events could be called in any one year, for a maximum of 4 hours, between 4-8pm on weekdays. Participants were offered a subsidy of £50 of vouchers on joining the trial, and a further £50 of vouchers at the end of the trial. They also received a DECC-subsidised ASHP installation, worth an average of £3,500, and a year's free broadband, worth £277. It is noted that this is a very small trial and further research is required to better understand response and methods of avoiding payback issues.

Scheduled Indirect Control

With respect to scheduled indirect control, CLNR included a demonstration of static Time of Use (ToU) tariffs for residential flexible demand [32]. New commercial arrangements were trialled that demonstrate a supplier hub arrangement which allows pass through of three-rate (distribution use of system) DUoS charge to residential consumers with smart meters. Monitoring data sets and average profiles of expected response for static ToU customer classes were produced along with guidelines for future commercial frameworks and commentary on barriers to mass uptake

The project highlights that ToU DUoS is being made available to all customers and that CLNR demonstrates how settlement can be achieved. The reporting [32] indicates that uptake would be supplier-led and identifies the wait for smart meter roll-out and the lack of supplier incentives as barriers. Assuming barriers are removed, the CLNR conclusions retain the possibility of some future use of this solution. The position seem to be that if suppliers roll out ToU there could be some benefit realised by the DNO. The business case is limited by the perceived lack of benefit to be obtained rather than costs to deploy the solutions, as reflected in the following statement "*The key costs to implementing static time of use tariffs are smart meter infrastructure, billing and IT systems, communication and customer interactions. The type of systems that would be required for the interventions trialled in CLNR are being implemented, and are therefore not regarded as additional costs. Similarly, marketing and acquisition costs for suppliers are not assumed to be any different than for other commercial products, and are not regarded as additional costs"* [33] (page 47).

4.2.1.1 Key Learning

The key learning published in the reporting referenced in this section is set out below.

Event-driven, direct control:

- I&C customers:
    - The flexible demand resources that participated were available for 50% of the agreed windows on average and had a success rate when called of 94%.
    - The reliability levels experienced during the trials means that DNOs need to over-procure to achieve the required level of network security
    - I&C Flexible Demand gives the DNO potential to defer or avoid primary network reinforcement investment – however the DNO must determine the relevant reliability factors (F factors) to ensure security of supply can be maintained.

    - The DNOs are effectively in a competitive market for flexible demand primarily with the National Grid STOR products. There may be a complementary aspect that allows joint products to add value to all stakeholders.
    - The location of flexible demand provision in specific geographic locations is necessary for DNOs but has proven to be challenging to achieve
    - The lead times from making initial contact with a customer to finalising a flexible demand contract can range from 12 to 24 months
    - It is easier to procure flexibility from standby generation than find a truly flexible load
- Domestic customers (smart washing machines)
    - Flexible Demand event signals were not received by 37% of customers on average.
    - Of the customers who received signals only 4% could be confirmed as allowing a delay to operation. For 84% of customers the machine did not run but this cannot be confirmed as response to a signal (i.e. no use may have been planned anyway).
    - From comparison of flexible customer load profiles with the baseline group, a statistically significant (reported by the project as at the 5% level) decrease in average power during the 4pm to 8pm peak window of 11 W was observed.
- Domestic heat pumps
    - A 67% response rate for interruptions.
    - On average, it appears that power consumption was reduced by approximately 1kW during the hour-long interruption, but then increased by just over 0.5kW for the hour-long period after the event.

Scheduled Indirect Control (ToU tariff):

- A mean peak reduction of between 3.2% and 12.5% for static ToU customers compared to the standard customer baseline with significant variability.
- There was no mean peak reduction on the specific half hour of peak system demand (17:30 to 18:00 on Friday 18th January 2013).
- The results of the trial indicate domestic ToU would be unlikely to provide sufficient benefit to avoid network reinforcement.
- It is noted that the recruited ToU customers were incentivized early adopters who by definition had an interest in responding to a ToU tariff.
- Customer incentives of £150 in vouchers were used for recruitment.
- A generalised benefit assessment for all stakeholders indicates a potential benefit of £23/yr/customer. The DNO share of this value is £5/yr/customer.

4.2.1.2 BAU Assessment

<u>I&C Call-Off Contracts</u>

The CLNR trials demonstrated that the use of I&C flexible demand is a technically viable and potentially cost effective option for the DNO. NPG include this option in their solution Merit Order and indicate an intention to deploy this in RIIO-ED1. **BAU Score: 3.**

<u>Residential ToU Tariffs</u>

The CLNR trials demonstrated that some benefit could be obtained through residential ToU tariffs; however, a positive CBA could not be made and barriers around the supplier relationship and to achieving sufficient reliability in geographically specific areas were identified. **BAU Score: -1.**

<u>Residential Appliance Control</u>

The CLNR trials indicated very limited benefit from the control of smart washing machines. NPG indicate that they do not expect this solution to be adopted for network purposes without significant technical and commercial development. **BAU Score: -3.**

Residential LCT Control

The CLNR Heat Pump trials in this area demonstrated potential benefits; however, the trial size was very small and no conclusive evidence can be drawn from the results. **BAU Score: 0.**

4.2.2 UK POWER NETWORKS

UKPN's LCL project undertook a large programme of demand side trials, including both domestic and I&C customers.

Trials of event-driven, direct control, flexible demand included the dispatch of I&C customer load and dispatch of EV charging load. A simulation of domestic smart appliance control was also conducted.

The I&C customer element of the LCL project was a trial of technical and commercial options for procurement and call-off of load reduction and standby generation [34]. The trial engaged mainly aggregator managed demand and generation. Dispatch signalling by phone and by ANM system were both tested. Planning tools, a CBA methodology and commercial frameworks were developed. The contractual model had an availability payment of £50-100/MW/h and utilisation payment of £200/MWh. Pre-fault (calling on demand reduction at all times required to ensure sufficient capacity exists in case of a fault) and Post-fault (only calling on demand reduction in case of a fault), were considered.

The trial results demonstrate a level of technical and commercial viability of I&C flexible demand. The foundations to allow BAU deployment appear to be established. The planning process (including security of supply considerations) has been examined and use-cases of upgrade deferral and outage management have been studied. Concerns regarding the reliability of flexible demand as a post-fault response were raised by UKPN control engineering teams, prompting further analysis of pre-fault operation; however, the increased costs were found to outweigh the benefits.

The LCL project undertook a simulation of smart appliances for demand response [35]. Data gathered through LCL network monitoring and household surveys was used to build an LV network model populated with residential customers with known appliance ownership. Modelling focussed on shifting the disaggregated wet white goods load profile to assess the impact on peak demand.

The simulation results presented confirm that the peak shaving potential of smart appliances is broadly within the range identified by previous studies, in the order of 10% for a winter weekday. This level of peak reduction can theoretically be achieved by implementing centralised optimisation of smart appliance control in a given network area. A simpler heuristic method (similar to tele-switch codes) was also tested where all appliances were sent a defer and recover schedule. No significant peak reduction was observed and cold-load pick up issues occurred. The modelling was an academic exercise demonstrating the theoretical potential of smart appliance control.

A trial of ANM for EV charging points was undertaken by LCL [36]. An ANM controller at the substation monitored capacity and issued load shed requests to an EV charge controller that monitors available 'shed-able' load at public charging points and responds to requests where possible. The technology has been proven to the extent that an ANM system could successfully shed EV loading; however, the published results demonstrate that large load sheds for prolonged durations could not be met in this trial. The project reports, "*The trial results suggest that, with some additional work, there is a high likelihood that the system could provide considerable network benefits.*" [36] (page 48). From the presented results, it would appear that significant additional study of charging behaviour for this type of charge point is required along with

development of more efficient control systems. In some extrapolation work a CBA was made for a high EV uptake scenario where ANM was mandated for residential EV connections. The modelled reduction in primary substation peak load (investment deferral) for the LPN area weighed against the cost of this ANM solution suggests a negative net present value (NPV) of around £300m.

LCL trialled scheduled indirect control with domestic consumers using new commercial arrangements that allowed a DNO designed dynamic Time of Use (dToU) tariff to be passed through the energy supplier to customers with smart meters [37]. Price events were communicated to consumers on a day-ahead basis. The tariff design included two types of event – network constraint management and supply-following of wind generation. Statistical analysis provides insight into response levels and planning case studies provide a framework for evaluating the benefit of the dToU for deferral of substation upgrade. 13 constraint management events were tested (mainly winter peak hours, from 1 to 3 consecutive days) and a wide range of high and low price supply following events tested over 93 days. Costs of running the trial are reported as £245 per customer for set up and £105 per customer per annum operating costs. UKPN's CBA work [38] indicates excessive costs involved in harnessing residential flexible demand via tariffs. The need for mandatory roll-out from suppliers and the significant changes in billing and IT systems etc. are highlighted as additional barriers not included in the basic CBA. The analysis maintains there is some possibility that residential flexible demand may offer some value in the future but states a list of challenging pre-requisites.

LCL also included a trial of 10 EV customers on a ToU tariff compared with a control group of 58 customers on a standard tariff [36]. The analysis considers the volume of charging that occurs in and outside the off-peak period (between 21:00 and 07:00) when off-peak price is discounted by 20%.

4.2.2.1 Key Learning

The key learning published in the reporting referenced in this section is set out below.

Event-driven, direct control:

- I&C customers:
  - Generation-led flexibility delivered 95% of the requested response for 30% of summer 2013 and winter 2013/14 events, and demand-led flexibility delivered 95% of the requested response for 48% of these events.
  - Indicative figures for F-factors[11] have been derived that are consistent with the present network security standards. However, it is stressed that the LCL data sets used to produce the F-factors have limited statistical robustness resulting in a future need to perform more trials.
  - Post-fault operation offers more benefit due to reduced dispatch; however, UKPN control engineers express concern over operational viability.
  - An example CBA for constraint management upgrade deferral of 4 years is positive, assuming an availability from December to March of 11 hours per day, 5 days a week at £30/MW/h.
  - Pre-fault operation requires up to 373MWh of dispatched energy in final year of the above 4 year example.
  - CBA analysis indicated pre-fault operation was not commercially viable.
  - Using generic reinforcement cost assumptions and a post-fault DSR model the opportunity across London Power Networks (LPN) area to defer reinforcement during ED1 and ED2 combined is estimated at £5.5 million.

[11] F-factors are currently used within distribution network planning standards to assess the contribution of DG to security of supply. The same principles can be used to assess the contribution of flexible demand.

Scheduled Indirect Control:

- Domestic ToU tariff:
  - Peak reduction is shown to vary significantly by customer group/type.
  - Average response figures are a reduction of around 50W per customer (7.8%).
  - A potential for negative impact on local network peaks is observed with the supply-following model.
  - Participant feedback indicates a positive experience in general.
  - A CBA was undertaken for this solution with benefits to primary substation reinforcement assessed. Projected costs of £207/customer heavily outweighed an estimated benefit of £25/customer.
- EV ToU tariff:
  - The trial showed that 70% of domestic EV users modified their charging behaviours to predominately charge their vehicle at off-peak times, despite the monetary incentive being small.
  - CBA modelling which assumed a mandatory roll out of ToU EV charging and a 30% reduction in EV load demonstrated a net benefit if the costs of implementation are below £20/household
  - Trial set up costs are stated to be £350/household.

4.2.2.2 BAU Assessment

<u>I&C Call-Off Contracts</u>

The LCL trials demonstrated that the use of I&C flexible demand is a technically viable and potentially cost effective option for the DNO. Some barriers remain regarding the policy regarding use for post-fault scenarios. **BAU Score: 3.**

<u>Residential ToU Tariffs</u>

The LCL trials demonstrated that some benefit could be obtained through residential ToU tariffs; however, a positive CBA could not be made and barriers around the supplier relationship and achieving sufficient reliability in geographically specific areas were identified. **BAU Score: -1.**

<u>Residential Appliance Control</u>

The LCL simulation work in this area demonstrated some benefits could be obtained; however, this relies on major assumptions and without field trials, major uncertainty remains. **BAU Score: -1.**

<u>Residential LCT Control</u>

The LCL trials in this area demonstrated potential benefits could be obtained; however, the evidence is not conclusive and various assumptions are included in the analysis. A positive CBA based on replication of the trial technology could not be made. **BAU Score: -1.**

4.2.3 WESTERN POWER DISTRIBUTION

The FALCON Project demonstrated event-driven direct control using I&C flexible demand [39]. This was a two phase trial of technical and commercial options for aggregator managed I&C customers. Phase 1 recruited only flexible generation participants and failed to attract any load reduction participants. Phase 2 results were yet to be published at the time of this review. In phase 1, 11 aggregator sites were operated for a total of 17 weeks with 18 events. Varying sizes of DG were employed: 5 sites at less than 400kW, 5 sites between 400kW and 999kW, and 1 site at greater than 1MW. These trials are based on a pre-fault use case. From the project reporting, the commercial and technical frameworks appear to be well established and

replicable. Phase 2 will increase payments from £300/MW to £600/MW, re-recruit, and work on week ahead notification.

The BRISTOL project included a demonstration of scheduled indirect control via ToU tariffs to encourage energy use during periods of high PV output, and to discourage energy use during periods of network stress. Final reporting was not available at the time of review; however, some indicative learning on ToU has been provided in progress reporting [40]. The model used by Bristol is that of retrospective compensation to customers for responding to ToU signals, as opposed to an actual tariff. A first calculation on ToU savings has been completed, and cheques issued to the customers. For the initial period from commissioning to April 2015, the payments varied from £6.24 to £181, in part due to the phasing-in of participants.

The Community Energy Action project [41] engaged with a range of diverse communities all fed from a single distribution transformer. The objective of the project was to test whether network loading could be reduced by community behaviour change. Interventions were led by local charities and included door to door visits, coffee mornings, home energy monitors and promotional campaigns for LEDs, slow cooking and energy efficiency.

4.2.3.1 Key Learning

The key learning published in the reporting referenced in this section is set out below.

Event-driven, direct control:

- I&C customers:
  - Flexible generation is easier to recruit than flexible demand.
  - An availability of 66.3% was observed.
- Residential ToU tariffs:
  - Some response observed but insufficient learning reported to make judgement at the time of this review.
- Community Engagement:
  - The methods trialled for community behaviour change did not achieve demand reduction in sufficient quantity or reliability to influence peak network loading.

4.2.3.2 BAU Assessment

<u>I&C Call-Off Contracts</u>

The FALCON trials are still underway and learning outcomes are yet to be fully published at the time of this review. However, initial findings indicate some success but highlight difficulties with the commercial proposition for demand customers, and the reliability of response from the contracted generation customers. **BAU Score: 1.**

<u>Residential ToU Tariffs</u>

The BRISTOL trials have produced limited outcomes at the time of review and the evidence is, therefore, inconclusive. **BAU Score: 0.**

<u>Community Engagement</u>

The Community Energy Action trials produced conclusive evidence against the tested methods of Community Engagement. **BAU Score: -4.**

4.2.4 SCOTTISH AND SOUTHERN ENERGY POWER DISTRIBUTION

The NTVV project includes an on-going event-driven direct control trial of an automated demand response (ADR) system that interacts with customer building management systems to control plant such as air-con

and refrigeration in the south of England. A published interim learning report analyses 83 events across 11 customers [42].

A pre-cursor to the NINES project, tested a new range of domestic energy efficient storage heaters and immersion water heaters (hot water cylinders) designed for grid energy storage, demand side management and frequency response, with communications link back to a central control point [43]. Control of the heaters was implemented through a daily schedule comprising 96 15-minute blocks. GPRS communications was used. The initial trial was essentially a technology demonstration with limited numbers. Further deployment is reported to be underway in NINES targeting around 700 homes; however, no results were published at the time of this review.

The My Electric Avenue project (originally Innovation Squared) trialled the direct control of clusters of EVs in daily operation across ten locations, including nine residential areas (charging at home) and one business location (charging at work). These locations cover urban, suburban, rural and commercial network types. The control philosophy was to cycle EV charging demand within the limits of the secondary substation capacity. The communications technology was Power Line Carrier. This project is a demonstration of EV charging management (branded Esprit) on an LV Network provided by a 3rd party (EA Technology) under contract to the DNO. Project close down reports were not available at the time of review; however, learning papers from the trials had been published [44, 45].

4.2.4.1 Key Learning

The key learning published in the reporting referenced in this section is set out below.

Event-driven, direct control:

- I&C customers:
  - The average ADR load reduction achieved was 11.3% and of the 83 events held, 73% were successful.
  - No financial incentives to customers were provided; hence significant recruitment efforts were required to establish customer relationships.
  - Early indications are that this ADR technology is most effective in periods of higher temperature (cooling load rather than heating load), so is applicable to summer peak situations.
- Domestic storage heaters:
  - The GPRS communications system suffered significant data loss and was deemed not fit for purpose.
  - Measured energy storage capacity was 12.1 and 14.9 kWh for the two sizes of storage heater and 14.0 and 17.1 kWh for the two sizes of hot water cylinder.
- EV charging:
  - The concept of 3rd party provision of managed EV charging to provide network benefits has been demonstrated
  - Modelling of the solution demonstrated mitigation of thermal constraints in all types of residential networks, delivering thermal headroom of up to 46% at the highest levels of EV uptake
  - Reporting on the trial results indicates that the control logic was simplistic and although the "system concept holds great potential to manage future network loads it requires integration to an effective means of communication and further development of the control logic". [44] (page 64)

- Modelling with the Transform[12] model suggests that Esprit will be an economic solution and will start to be deployed around 2021 dependent on the specific EV growth scenario.

4.2.4.2 BAU Assessment

I&C Direct Control

The NTVV project is still underway and results are not fully published at the time of this review. Indications of benefit are available however the current evidence for I&C flexible demand is inconclusive until full learning is available. For these reasons, a BAU assessment has not been made.

Residential LCT Control

The My Electric Avenue project demonstrated the technical and commercial concept of managed EV charging; however, the project indicates the need for further development of the solution and further trials are needed to generate strong evidence for adoption. The solution is thought unlikely to be required in RIIO-ED1. **BAU Score: 2.**

4.2.5 ELECTRICITY NORTH WEST

ENWL tested event-driven direct control in two I&C customer projects.

The Capacity 2 Customers (C2C) project included a trial of flexible demand contracts for both new and existing I&C customers within new network operation arrangements [46]. Standard radial HV feeder operation with normal open points and N-1 redundancy was replaced with closed loop operation and 'non-firm' customer connections, allowing circuits to be operated close to capacity without, or with lower, redundancy for fault conditions. The non-firm connections were tripped in the event of a fault and restored if possible via the post-fault automatic restoration scheme. Ten new and ten existing customers were trialled. The ten existing customers were trialled via contract with an aggregator based on a commission model with a mid-point target of £20k/MVA per annum. In addition to the commission levels there was a £9250 set up fee and £190 per customer finder's fee.

The project close down report states a clear intention to adopt the C2C solution as business as usual. However, it is noted that generalisation is difficult and individual network analysis is required to determine suitability of the method on a case by case basis, *"During the lifetime of the Project the C2C concept has become readily established and has subsequently been deployed by other DNOs as a business as usual activity. For Electricity North West, the C2C Method will form part of a suite of strategic interventions for RIIO-ED1"* [46] (page 47).

The CLASS project aimed to explore the voltage/demand relationship and demonstrate a solution that can reduce peak network demands and provide a new mechanism for DNO provision of ancillary services to the GB system operator [47]. The trials deployed autonomous substation controllers (ASC) at 60 primary substations. The ASC was activated centrally by the control room Network Management System (NMS) then operated in conjunction with the existing AVC relay to provide On Load Tap Change (OLTC) functionality. For ten sites the ASC was also able to trip one of the primary transformers circuit breaker, reducing voltage due to the increase in impedance. The ASCs were also linked to the System Operator NMS via an (Inter-Control Centre Communications Protocol) ICCP link.

The trials undertaken are described in the table below.

[12] A model that has been developed to assist the evaluation of investment options for electricity distribution networks. A product of the DECC and Ofgem Smart Grid Forum.

Reference	Description	Objective	Technique	Trial period	Customer survey requirement
T1	Load modelling	Establish voltage/demand relationship	Raise and lower tap positions	Across entire annual cycle	No
T2	Peak demand reduction	Demand response for peak reduction	Lower tap position	Peak demand	Yes
T3a	Stage 1 frequency response	Response to reduce demand when system frequency falls	Switch out transformer	Anytime	Yes
T3b	Stage 2 frequency response		Lower tap position	Anytime	Yes
T4	Reactive power absorption	Reduce high volts on transmission network	Stagger tap position	Minimum demand	No

Figure 10: CLASS Trials Overview – reproduced from [47]

The project states that the CLASS methodology has the potential to be used to offer balancing services to NG: fast reserve (FR), frequency control management demand (FCDM) and firm frequency response (FRF), using automatic relay operation for a non-dynamic response. The project assessed the regulatory, customer impact and asset health implications and concluded that no changes are required to current standards (SQSS, DCODE, GCODE). There is a negligible impact on asset health and the use of voltage reduction techniques does not cause any detriment to customers' perception of quality of supply.

The high level cost benefit analysis for the CLASS method is considered based on minimum benefits from applying a 1.5% voltage reduction. Applied to all primary substations in the project area, ENWL calculate a gain up to 12.8MVA of network capacity that enables deferred reinforcement of five primary substations with an associated expenditure of £2.8 million for up to three years. A primary substation can be retrofitted in one week at a cost of £44,000 compared with the typical average time to reinforce a primary substation of 57 weeks at a cost of £560,000. The cost-effective deferral of reinforcement provides a valuable flexibility where significant uncertainty exists. The project notes that very significant additional revenues could be achieved by the CLASS method through the provision of ancillary services. This is dependent on wider changes in the regulatory environment.

4.2.5.1 Key Learning

The key learning published in the reporting referenced in this section is set out below.

Event-driven direct control:

- Flexible (non-firm) connections:
  - Connection charges of £7.84m expected under standard connection processes was reduced to £0.37m for the new customers.
  - For 20 fault occurrences: customer interruptions (CIs) increased by 15% and customer minutes lost (CMLs) decreased by 24% compared to the radial equivalent. Short duration interruptions (SDI) increased by 83%.
  - It is estimated that the C2C solution could release 3.1GW of existing capacity on the ENWL HV networks.
  - 2050 scenario analysis indicates the C2C solution along with an optimal upgrade strategy could enable between £50m - £70m of saving for ENWL and between £0.6bn and £1.2bn for GB as a whole.

    - With respect to the ETR130 security of supply standard, the project proposes that an appropriate allowance for Flexible Demand is taken into account when calculating group demand; however, it is up to each DNO to decide the level of allowance and to justify its approach.
- Voltage reduction:
    - A 1% voltage reduction at a primary substation produces a seasonal average real power reduction in the range of 1.3% - 1.36% and an average seasonal reactive power reduction of 5.54% - 5.83%.
    - Applying these results to overall peak demand reduction for the ENWL area indicates:
        - A 57MW (summer minimum) to a 163MW (winter maximum) for a 3% voltage reduction.
        - A 94MW (summer minimum) to a 271MW (winter maximum) for a 5% voltage reduction.
    - Extrapolated to the whole of the GB network:
        - A 700MW (summer minimum) to a 2GW (winter maximum) for a 3% voltage reduction.
        - A 1.2GW (summer minimum) to a 3.3GW (winter maximum) for a 5% voltage reduction.
    - Extrapolation work indicated that, when applying a six tap stagger, levels of reactive power absorption for the Electricity North West distribution area could be in the region of:
        - Summer: 133MVAr to 152MVAr
        - Winter: 131MVAr to 167MVAr
    - A GB extrapolation shows:
        - Summer: 1.47GVAr to 1.67GVAr
        - Winter 1: 1.44GVAr to 1.83GVAr

4.2.5.2 BAU Assessment

<u>I&C Flexible Connection</u>

The C2C project provides a strong evidence base that indicates a strong case for the solution to become a BAU option for all DNOs. ENWL states a clear intention to adopt C2C as business as usual. The solution is not general and requires case-by-case analysis. In addition, issues around customer interruptions may still present a barrier to deployment. **BAU Score: 3.**

<u>Voltage Reduction</u>

The CLASS trials have provided a strong case for the deployment of voltage management solutions for demand reduction as a BAU option for all DNOs. The solution is technically feasible and cost-effective in its simplest format. However, frequency response functionality requires significantly more work. **BAU Score: 3.**

4.3 Discussion

With respect to the Learning Topic categories identified for this review, virtually all applications of flexible demand have been for Power Flow Management. Control methods have either been scheduled indirect control or have been event-driven direct control where the demand resource has been dispatched with respect to a single, locally measured constraint (e.g. substation load). The minor exception to this is the CLNR project which dispatched demand resource from an area control scheme (the field trial did not include coordination with other resources) and then modelled the coordinated control of demand resource with other power flow management and voltage control resources.

4.3.1 Event-Driven Direct Control

<u>Voltage Reduction</u>

The CLASS project has demonstrated that voltage reduction can provide a cost effective demand reduction technique that can unlock capacity across the network. Voltage control policy is discussed in more depth in later sections of this report; however, this clearly represents an area of opportunity for DNOs. Functionality to enable frequency support services has also been developed.

I&C Flexible Connections (non-firm)

The C2C project allows the connection of I&C load that would not normally be connected under N-1 Security of Supply planning standards. By establishing a non-firm connection agreement where customer load is tripped in the case of a fault, the network need not reserve the additional capacity required to otherwise maintain supply to all customers in the case of a fault. As such, it represents an opportunity to unlock significant network capacity. However it is not a traditional flexible demand concept and requires customers willing to be integrated into the DNOs automatic fault restoration system.

I&C Call-off

The CLNR, LCL and FALCON projects all tested contractual flexible demand with I&C customers based on availability and utilisation. A use-case of upgrade deferral for primary substations approaching firm capacity was common to all projects, with flexible demand utilised to achieve compliance with the P2/6 security of supply standard. The approach to pre or post fault flexible demand varied between projects. Some considered one option only. LCL identified that the increased utilisation payments for pre-fault flexible demand caused a positive CBA to be extremely challenging; however, post-fault flexible demand was deemed unacceptably risky by the control engineers. All projects provided a contribution to the understanding of flexible demand reliability (F-factors) required to plan and procure the necessary flexible demand resource. A range of commercial models were tested. DNO-specific requirements for flexible demand were established and the need for coordination with the TSO was highlighted (to avoid unnecessary competition for the same flexible demand resource). The NTVV project has some initial positive indications regarding control of I&C load via building energy management systems, but full learning outcomes are yet to be published at the time of this review.

Residential Appliance Control

Control of wet white goods was tested by CLNR. The project suffered from communication issues and showed only very small net reduction in demand in response to signals.

Residential LCT Control

LCL and My Electric Avenue tested controlled EV charging. The LCL trial focussed on public charging points controlled via an ANM system. The LCL results provide evidence that an ANM system can successfully request an EV load shed; however, the extent of load shedding and reliability of response were not clearly established. In addition, a CBA exercise for primary substation upgrade deferral did not indicate that this was an economic solution. My Electric Avenue focussed on the LV network and residential EV charging. The DNO outsourced the managed charging solution to a 3rd party who curtailed EV load in response to thresholds on the secondary substation. The trials provide a proof of concept and enabled some analysis of benefit using the Transform model. However, reporting on the trial results indicated that the control logic was simplistic and communication issues hampered the reliability, hence further development and testing is required. A very small trial of heat pump control was implemented in CLNR that provides the foundation for further development and testing to understand the level of response that could be achieved and the issue of 'cold-load pick up'[13].

[13] The loss of diversity when all interrupted loads are restored at the same time.

4.3.2 Scheduled Indirect Control

Residential ToU tariffs

CLNR tested a static ToU tariff, and LCL tested a dynamic ToU tariff with constraint management and wind following variants. The trials were extensive and large amounts of smart meter data and statistical analysis are available. In general, the projects indicate that the (self-selecting) customers participated enthusiastically and average peak demand reduction in the order of 7-10% can be achieved. However, the results are mixed and do not provide a clear body of evidence on the level of demand reduction, or reliability, that could be expected, particularly for days of critical peak loading when the response is most required. Assessment of which costs should be included (smart metering, ICT systems, supplier integration) in a CBA for residential flexible demand vary between the projects. Both projects indicate that the concept of residential ToU tariffs should not be abandoned and that the smart meter roll-out and move to half hourly settlement for all customers continues to represent an opportunity. Deriving benefit will, however, require significant further work, particularly the necessary collaboration with suppliers to enable the pass-through and marketing of ToU DUoS charging. Cross-supplier coordination in order to enable the geographically focussed response essential to DNOs is also a critical issue.

A small trial of ToU tariffs for EV charging indicated that this offers a significant flexibility and is worth further research.

4.4 BAU Overview

The work by ENWL has developed two highly innovative solutions that appear to be ready for consideration for BAU by all DNOs. In addition, contractual on-demand I&C flexible demand has been tested by several projects and the body of evidence indicates this should be developed as a BAU option by all DNOs. Conversely, the results of trials on residential direct control and tariffs has demonstrated limited benefit. Further work is required to understand how DNOs may extract a cost-effective benefit for networks from this resource. LCT control appears to offer more potential for DNO benefit; however, solutions are at an early stage of development and are not expected to be required until ED2. An overview of the BAU scores is shown in Figure 11. Aside from voltage reduction innovations, all the interventions summarised in Figure 11 concern commercial arrangements.

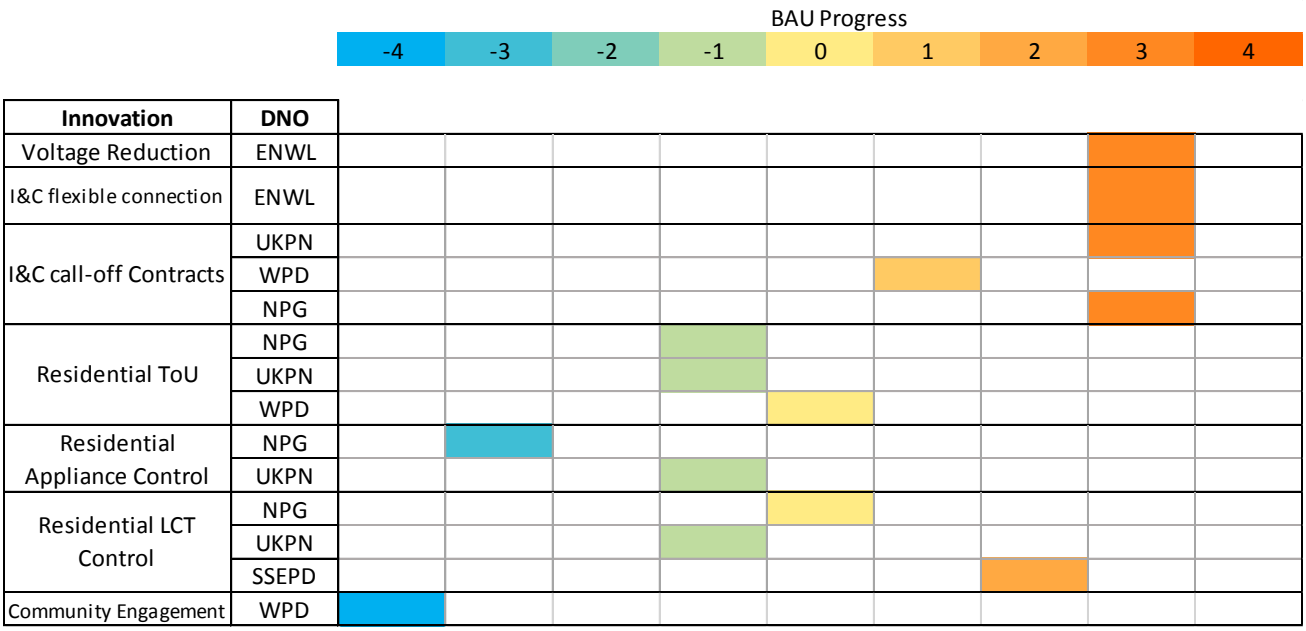


Figure 11: Flexible Demand BAU Assessment

4.5 Synthesis of Learning

The synthesis of learning and associated recommendations derived from the review in this section are set out below.

Learning:

- Voltage reduction to achieve general demand reduction has been demonstrated successfully; all DNOs should consider the application of this as a BAU option.
- The C2C project's solution for managed flexible connection of I&C demand should also be considered as a BAU option by all DNOs.
- On-demand dispatch of I&C demand (call-off contracts) has been successfully trialled and should be progressed to a BAU option by all DNOs. Challenges remain to reduce uncertainty around reliability, CBA and acceptable risk for post-fault flexible demand.
- Residential Time of Use tariffs have shown limited potential in the LCNF trials. Although some peak reduction was achieved, the solution was deemed unlikely to provide sufficient benefit to avoid network reinforcement.
- Residential direct demand control trials also achieved limited network benefits.
- As trialled in LCNF projects, residential flexible demand is unlikely to be a solution deployed by DNOs although if rolled out by suppliers, DNOs may derive some benefit.
- LCT direct control has shown good potential; however, trials are for relatively small numbers and the technology is at early stages of development.

Recommendations:

- Further collaborative efforts to establish best practice in voltage reduction and the potential for offering frequency response should be undertaken by the DNO community.
- Further dissemination of the C2C method should be undertaken with all DNOs formally assessing its potential for their network areas.
- Collaborative efforts to establish industry best practice for I&C flexible demand should be undertaken addressing:
    - The geographical nature of flexible demand requirement.
    - The best methods of contracting flexible demand.
    - Improved understanding of reliability and appropriate planning methods.
- Data-sets from the LCNF I&C trials should be consolidated in order to provide further insight to appropriate methods of accounting for flexible demand within industry security of supply standards and to identify further work required to improve the understanding of risk for post-fault flexible demand.
- New methods of harnessing the potential of residential demand response should remain an innovation priority in parallel with efforts to establish the necessary frameworks with suppliers to enable DNOs to access this resource.
- LCT direct control should remain an innovation priority, developing the technical and commercial understanding of such solutions, in addition to the development of appropriate planning tools in readiness for significant LCT adoption.

5 Synthesis of Learning on Generator Control

The heat map identifies a high level of activity around the control of generation connected to the distribution network. The innovations investigated are primarily focussed on the technical and commercial aspects of active network management (ANM) of distributed generation (DG).

The review considered:

- What is the learning on control of DG for Power Flow Management and Voltage Control purposes?
- What is the learning on commercial arrangements for actively managed DG connections?
- How close to BAU are the tested methods of generator control?

The projects reviewed are shown in Table 16.

Title	DNO	Budget (£m)	Tier	Start Date	End Date
Low Carbon London	UKPN	28	Tier2	Dec 10	Dec 14
Flexible Plug and Play	UKPN	6.7	Tier2	Dec 11	Dec 14
Low Carbon Hub	WPD	2.8	Tier2	Dec 10	May 15
Seasonal Generation Deployment	WPD	0.3	Tier1	Jul 11	Aug 14
Hydro Active Network Management	SPEN	0.2	Tier1	Mar 12	Dec 14
Accelerating Renewable Connections	SPEN	7.4	Tier2	Dec 12	Dec 16

Table 16: DG Projects

5.1 Project Details

5.1.1 UK POWER NETWORKS

Low Carbon London originally intended to include ANM trials. However, "*in practice, no opportunities were found either to offer a new flexible ANM-managed connection to the network or to directly manage and existing DG site to provide a DSR service*" [48] (page 10). Instead, the ANM system was used for monitoring of CHP (13 sites) and PV (four G83 and four G59) to derive behaviour profiles and gain improved understanding of the contribution of DG to security of supply [49]. The motivation behind this work recognised that although engineering recommendation P2/6 and ETR130/131 allowed DG contribution to be taken into account during planning, this was often neglected due to lack of confidence in the current understanding of DG contribution and a lack of specific visibility and data on the actual DG concerned. A detailed characterisation of DG on the London network has been undertaken and adaptations of P2/6 and ETR130/131 have been applied to assessment of a selection of case studies. New insight has been gained into F-factors for various types of DG.

The main constraint on DG connection for UKPN in London are fault levels (as with other dense urban areas). The recommended monitoring described above is also relevant to the implementation of ANM for fault level constraints, as the contribution of existing DG will need to be understood. A high level modelling exercise was also carried out in this project to assess the additional capacity that ANM could unlock on London networks.

That additional capacity released by ANM is based on two principles:

- Recognising the network reconfiguration, i.e. the difference between fault level headroom in intact and outage conditions
- Recognising the status of Short Term Parallel (STP) connected generation, i.e. releasing the capacity locked by STP DG when possible.

The Flexible Plug and Play (FPP) project specifically focussed on the technical and commercial challenges of flexible DG connections where the DNO has control over generation output [50, 51]. The trial area in Cambridgeshire had 90MW of connected wind generation plus an additional 57MW of generation with accepted offers and a further 34.5MW of generation had requested offers. Network assets in the area were known to be approaching capacity. The network constraints identified by FPP were:

- Reverse power flow – the grid substation transformers serving the trial area have limits on reverse power flow which are dictated by the maximum settings that can be applied to the Directional Overcurrent (DOC) protection.
- Thermal Constraints arising at certain pinch points on 33kV lines.
- Voltage Constraints - voltage rise on the 11kV side.

The project tested an ANM system with associated commercial contracts for flexible generator connections. The commercial models were pro-rata[14] and Last In First Out[15] (LIFO). The pro-rata solution was implemented for reverse power flow constraint on one of the grid substations. The decision was made to introduce a capacity quota at the level where the cost of curtailment for all generators was equal to the cost of reinforcement. 13 generators chose to take connection offers for this commercial model. LIFO was applied in the other grid substation area where multiple constraints were present. Two generators chose to take up connection offers under these arrangements.

The ANM system was supplied by Smarter Grid Solutions (SGS). The ANM system was supported by an RF Mesh communications network and Dynamic Line Rating – both of which are reviewed in other sections of this report.

The FPP ANM trials suffered from delays in generator connection. A real-time simulation environment utilising the ANM vendor's hardware was built to allow testing of the specified use cases. The published results [50] are summarised below.

Power Flow Management

A simulated analysis of coordinated generator control (under pro-rata agreements) demonstrated successful curtailment of a set of generators based on their contribution to reverse power and thermal limit constraints. The simulation verified the control methodology satisfied the necessary timescales and safety parameters for a field implementation. Curtailment of a single DG unit under LIFO arrangements was successfully demonstrated in an operational field trial. Although the project tested other PFM technology controlled by the ANM platform, trials that demonstrated coordinated control of multiple technologies were not undertaken.

Voltage Control

Although scheduled generator connections indicated future constraints, power flow studies at the beginning of the project failed to identify an existing voltage constraint. A trial involving one firm and one flexibly connected generator was therefore conducted within the simulation environment. The results verify proof of concept for the voltage control application. The control method utilised the reactive power capability of the generator and, as a last measure, curtailed real power to successfully alleviate voltage constraints within the specified time scales and safety parameters. Although the project tested other VC technology controlled by the ANM platform, trials that demonstrated coordinated control of multiple technologies were not undertaken.

[14] Curtailment is shared across generators in an ANM zone.
[15] Generators are curtailed in reverse order of connection applications.

5.1.1.1 Key Learning

The key learning published in the reporting referenced in this section is set out below.

Learning from Low Carbon London:

- Monitoring of DG has been found to reveal either a DG contribution to security of supply or an underlying latent demand, masked by the DG, which requires reinforcement.
- Current DG penetration in the LCL area is insufficient to provide a significant contribution to security of supply and reduce network capacity requirements. However, in general, the trials have indicated a case for detailed monitoring of all DG connections to allow more accurate future assessments as penetration increases and maintain a database of DG-typical information such as availability and output profiles.
- Monitoring and ongoing review of connections also addresses the fact that when DG is decommissioned there is currently no systematic way of releasing capacity back to the network.
- Active management of DG is recognised as increasing the availability and hence contribution to security of supply. The project recommends that the performance of actively managed connections are monitored to allow a full assessment of these characteristics.
- ANM for fault level constraints could release an estimated potential additional capacity of 619 MW across 88 out of the 114 LPN primary substations.

Learning from Flexible Plug and Play:

- Existing ANM solutions can be deployed in a control centre environment (as opposed to substation deployment) with connection of ANM system to multiple 'smart devices' via IEC61850.
- Existing ANM solutions based on LIFO can be adapted to deliver a capacity quota-based scheme.
- In total the project saved accepted DG customers within the trial area approximately £36 million on their connection offers.
- Commercial templates[16] are available for the various commercial models trialled.
- The pro-rata approach leads to more customers being able to accept a connection offer based upon an expected level of curtailment that still makes the project financially viable. However, LIFO has a wider application that can be applied to more constraint types.
- Customers indicated that a pro-rata scheme is more likely to be financed than a LIFO scheme due to the risk sharing element.
- The pro-rata capacity quota defines the breakeven point where cost of curtailment = cost of reinforcement; however, the process for pro-rata customers to jointly pay for network upgrade requires further development.

5.1.1.2 BAU Assessment

<u>Actively Managed DG Connection</u>

UKPN's trials have shown that ANM of DG connections is technically and commercially ready for widespread deployment and benefits clearly justify costs. **BAU Score: 4.**

5.1.2 WESTERN POWER DISTRIBUTION

The Low Carbon Hub project focussed on trial and comparison of a suite of technical solutions for increasing DG connection capacity [52]. One area of focus was for new commercial arrangements around ANM connections. This project took on the SGS ANM system and concentrated on the commercial requirements to move it towards business as usual. The project also developed two new constraint analysis tools to

[16] Standardised connection agreements, offer letters, terms and conditions.

support the ANM planning process. Despite a recognition of the limitations of the LIFO curtailment method a decision to utilise this method was based on the perceived simplicity and clarity of the method and a broad acceptance of LIFO by stakeholders. The project has been offering 'alternative connections' since February 2014 with six accepted by the time of project close down report publication, allowing the connection of 48.8MVA of additional new connections with an estimated cost saving of £42m. ANM policies and Standard Techniques have been written for offering alternative connections as a BAU process. Planner training has commenced across the business and WPD is developing a core constraints analysis tool for calculating constraints in all ANM areas.

The Seasonal Generation Deployment project [53] aimed to develop a technical and commercial model for third party owned DG to be installed temporarily at substations during times of peak demand. The project was terminated in summer 2013 when it was proven to be uneconomic for generation owners to deploy units on a seasonal basis at a cost that would be lower than conventional reinforcement. The financial proposition for a trial substation identified an annual profit of £37k/MW per annum for a 3MW installation. However, the DNO contribution in this figure was £2.7k/MW with the rest of the value assumed from TRIAD and STOR revenue. Uncertainty over these revenue streams and other operational difficulties resulted in the aggregator (Flextricity) and DG supplier (Aggreko) deeming the risks were too great to enter into a commercial agreement.

5.1.2.1 Key Learning

The key learning published in the reporting referenced in this section is set out below:

- LIFO remains a popular commercial model that can enable faster, cheaper DG connections.
- ANM for the curtailment of individual DG connections via a reduction in real power output or an adjustment of power factor is now established as BAU and has enabled significant cost saving for DG connections.
- The technical and commercial challenges of seasonal deployment of generation at distribution network substations proved unattractive for 3rd party aggregators.

5.1.2.2 BAU Assessment

<u>Actively Managed DG Connection</u>

WPD's trials have shown that managed DG connections with ANM for Power Flow Management and Voltage Control is technically and commercially ready for widespread deployment and benefits clearly justify costs. **BAU Score: 4.**

<u>Seasonal Generation</u>

The trial of seasonal generation deployment provided strong evidence that this solution is technically and commercially unattractive. **BAU Score: -4.**

5.1.3 SCOTTISH POWER ENERGY NETWORKS

The Accelerating Renewables Connections (ARC) project focusses on the issue of lengthy connection delays and capacity issues for DG connecting to the distribution network in the trial area of East Lothian and the Borders [54]. A core principle of the project is to match local demand with community generation. The main areas of focus are stakeholder empowerment/information on connection options and the technical and commercial arrangements for DG connection. The project initially set out to expand the knowledge regarding ANM deployments. Seven ANM use-case studies were used to highlight potential learning.

- Case Study 1: The Exporting Grid Supply Point
- Case Study 2: Multiple Issues for N-1 Contingencies

- Case Study 3: A High Cost Firm Connection due to Thermal Constraints
- Case Study 4: High Cost Firm Connections due to Voltage Rise
- Case Study 5: The Infeasible Application (focussing on the SPEN connections policy and process)
- Case study 6: Insufficient Capacity for Small Scale Community Scheme
- Case study 7: Impact of Small Scale Generation on the Exporting GSP

The project is still in progress at the time of this review; however, interim progress reports have been published [55]. There are no specific learning outcomes reported with respect to the case studies above; however, reports indicate that relevant GSPs have been ANM enabled and the commercial templates for exporting GSP related ANM developed. A 1.6MW wind farm has been connected under a commercial agreement that satisfies SPEN, National Grid, and the developer. This connection has been moved forward from 2021. ARC reporting indicates that ANM is progressing to business as usual and is included in RIIO-ED1 plans. Active Network Design is being developed to allow ANM options to be included within the standard connections offer process. A stakeholder forum and an online Curtailment Analysis Tool have been developed to help improve stakeholder information and to avoid unnecessary analysis for infeasible connections.

A Tier 1 project (Hydro ANM) is implementing ANM for an 11kV voltage constraint. ANM will control on load tap changer (OLTC) settings and generator real/reactive power to maximise export [56]. No close down or learning outcome reports were published prior to the cut-off date for this review.

5.1.3.1 Key Learning

The key learning published in the reporting referenced in this section is set out below.

Learning from ARC:

- ANM for DG can resolve transmission network constraints
- Although ANM for larger, developer-led, DG schemes is progressing to BAU, establishing trials that include local demand and community generation appears to have been challenging.

5.1.3.2 BAU Assessment

<u>Actively Managed DG Connection</u>

SPEN's trials have shown that ANM is technically and commercially ready for widespread deployment for well understood DG connection scenarios; however, further work is required to harness the benefits of ANM for all stakeholders and to expand flexible DG connections to include the consideration of local demand. **BAU Score: 3.**

5.2 Discussion

Generator control trials have primarily focussed on the demonstration of Active Network Management of DG connections. Distributed generation with ANM for control of real power output and power factor settings have been demonstrated successfully and the commercial arrangements, standards and policies have been developed.

Using LCNF funding, two projects took on the SGS ANM products deployed successfully by SSEPD in Orkney and Shetland. The projects deployed the established LIFO commercial arrangement and enabled significant cost savings for 21 new generator connections:

- Flexible Plug and Play: £36 million saved for 15 generator connections (MVA)
- Low Carbon Hub: £42 million saved for 6 generator connections (48.8 MVA)

Pro-rata commercial models were also tested by the Flexible Plug and Play project and were found to offer greater efficiency in maximising connected generation but only for specific constraint scenarios. Customers responded positively to the pro-rata offering.

A question that could be asked of these projects is whether innovation funding was required to adopt solutions that were effectively BAU for another DNO. However, it might also be argued that use of innovation funding to transfer knowledge from one DNO to another is valid. Moreover, the projects did include novelty in the extent of ANM integration with existing control functionality and also tested pro-rata curtailment priority systems. Nonetheless, a more detailed analysis of this question would lend insight to future innovation funding policy.

The Accelerating Renewable Connections project has provided a platform to move ANM into a BAU process for SPEN. The focus on communities and, in particular, the potential of local demand adds an innovative element to ANM DG connections. The project will hopefully add learning on how constrained DG connections can be actively managed with local demand (behind the meter) utilised to avoid generator trimming/tripping; however, at this interim stage in the project, only two deployments have taken place.

UKPN's Low Carbon London also intended to deploy ANM; however, the project was unable to recruit any customers for an ANM-managed connection. Detailed monitoring of CHP and PV installations allowed insight to be gained on the DG contribution to security of supply. The findings indicated that current DG penetration is insufficient to be significant for security of supply but, in general, the trials have indicated a case for detailed monitoring of all DG connections to allow more accurate future assessments as penetration increases.

The established technical and commercial solution is based on monitoring pre-identified constraint points then responding with generator control in a LIFO commercial model. The limitations of this approach and the transition path from these isolated, local ANM solutions, to integrated area control schemes, represents a technical and commercial challenge.

5.3 BAU Overview

The UKPN and WPD projects have effectively demonstrated the benefits of ANM for managed DG connections using the LIFO commercial model. This should now be considered a BAU option for all DNOs. The SPEN ARC project has yet to report fully and seeks to expand the scope of an ANM managed connection to include local demand behind the constraint. The project has moved ANM of DG connections towards BAU for SPEN. The BAU scores are shown in Figure 12.

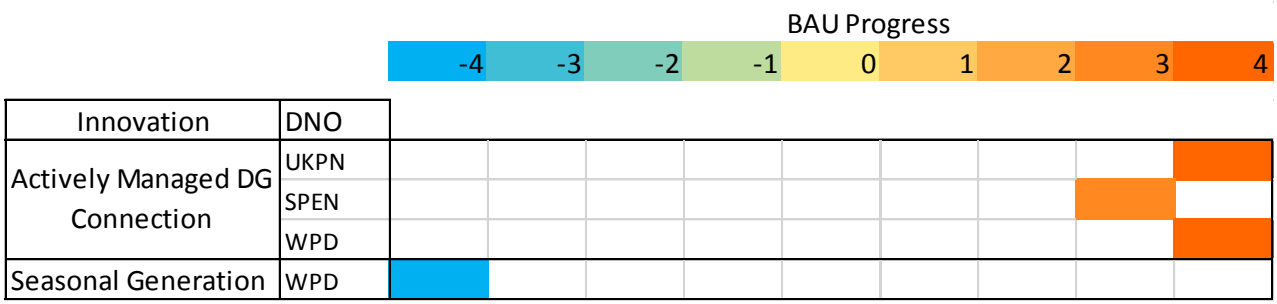


Figure 12: BAU Assessment of Generator Control Projects

5.4 Synthesis of Learning

The synthesis of learning and associated recommendations derived from the review in this section are set out below.

Learning:

- Active Network Management for DG connections should be a BAU option for all DNOs.
- The ANM solution has matured; extensive experience has been garnered and shared.
- DNOs have collaborated to produce an ANM best practice guide.
- Templates of commercial documents[17], planning tools and stakeholder engagement and information tools are now well-developed.
- The deployments are predominately stand-alone, local solutions based on measurement of pre-identified constraints, with control of generator output based on a Last in First Out commercial model.
- Pro-rata commercial models were trialled successfully and found to offer improved efficiency in maximising connected generation for specific constraint scenarios.
- Pro-rata was found to be suitable for reverse power flow constraint on grid substations; however, it was deemed technically unsuitable for more complicated situations with multiple constraints.
- Contracting with an aggregator for temporary installation of DG, i.e. seasonal deployment such as of diesel generators during the winter, was found to be technically and commercially unviable.
- The understanding of DG contribution to security of supply has been progressed and new data produced that can inform review of ETR130/131 and the current review of ER P2/6.

Recommendations:

- Detailed analysis of the ANM route to BAU, and the role of innovation funding at different stages in the process should be undertaken to inform future innovation project direction and policy for the development of other promising technologies.
- ANM solutions that account for and utilise load 'behind the meter' should be an ongoing innovation focus (depending on results from SPEN's ARC project).
- Alternative technical and commercial solutions and the transition to more coordinated, integrated wide area control should remain an innovation priority.
- There is the opportunity for a collaborative effort that utilises all relevant data from numerous LCNF projects (and other DG projects) to provide further insight into DG contribution to security of supply and to update ETR 130/131.

[17] Standardised connection agreements, offer letters, terms and conditions, etc.

6 Synthesis of Learning on Network Reconfiguration

The heat map identifies several projects that focus on the reconfiguration of the network for Power Flow Management and for restoration of supply following faults.

The review considered:

- What variants of network reconfiguration have been tested?
- To what extent can network reconfiguration innovations increase network capacity?
- To what extent can network reconfiguration innovations improve quality of supply?
- How close to BAU are the different network reconfiguration innovations?

The projects identified for review are shown in Table 17.

Title	DNO	Budget (£m)	Tier	Start Date	End Date
Smart Urban Low Voltage Network	UKPN	2.1	Tier1	Jun 12	Mar 16
Flexible Urban Network	UKPN	6.5	Tier2	Dec 13	Dec 16
Flexible Networks for a Low Carbon Future	SPEN	3.6	Tier2	Dec 11	Sep 15
FALCON	WPD	12.4	Tier2	Dec 11	Sep 15
The 'Bidoyng' Smart Fuse	ENWL	0.5	Tier1	Dec 10	Dec 14
LV Protection And Communications	ENWL	0.75	Tier1	Aug 13	Jun 15
Smart Street	ENWL	8.5	Tier2	Dec 13	Dec 17

Table 17: Network Reconfiguration Projects

6.1 Project Details

In the following sections, the projects listed in Table 17 are reviewed, summarised and the key learning is identified.

6.1.1 UK POWER NETWORKS

The Smart Urban LV Network project[18] concluded in March 2015. A close down report had yet to be published on the project or the Ofgem website by the cut-off date for this review. The project objective was a large scale trial of new solid state switching technology on LV networks. Specifically the project aimed to: develop a link box load monitoring device to retrofit into older cast iron link boxes; integrate the new hardware with a LV network management system; and evaluate the potential benefits of the new technology in terms of reduced losses, increased capacity headroom and early visibility of emerging loading or power quality issues.

In the absence of a learning report, it is assumed that these trials were successful enough to feed into the Tier 2 Flexible Urban Network – LV (FUN-LV) project that advances the LV automation solution.

The FUN-LV project[19] intends to build on UKPNs existing knowledge of LV interconnection and network management. Link box switches and remote control circuit breakers will create LV interconnected networks and power electronics devices will create soft open points and allow capacity sharing between substations. Although still in progress with limited learning outputs at the time of this review, it is mentioned here to highlight the expected areas of insight regarding this approach to LV network configuration. As the project intends to run demonstrations on 36 sites the majority of which are on radial networks, the learning should

[18] http://innovation.ukpowernetworks.co.uk/innovation/en/Projects/tier-1-projects/smart-urban-low-voltage-network/
[19] http://innovation.ukpowernetworks.co.uk/innovation/en/Projects/tier-2-projects/Flexible-Urban-Networks-Low-Voltage/

be relevant to the entire DNO community. The project is expected to demonstrate headline savings of £2.36m across the 36 trial sites. Projections indicate that a saving of up to £112.8m could be made in the latter half of ED1 and ED2 across the whole of GB. At the time of review, the project has developed the LV NMS system functionality and tested and deployed Link box switches (LBS) and remote control circuit breakers (CBs) in the trial area.

6.1.1.1 BAU Assessment

LV Interconnection

UKPN has undertaken extensive work in this area; however, the lack of reporting means evidence for BAU of the solution for UKPN and for other DNOs remains inconclusive. **BAU Score: 0.**

6.1.2 SCOTTISH POWER ENERGY NETWORKS

The Flexible Networks approach aimed to achieve incremental capacity on two 11kV network trail areas using automated switches to link neighbouring groups with spare capacity or different demand profiles [57]. This required upgrading of the existing tele-control functionality of the secondary network[20]. The new equipment utilised IEC61850 and IEC60870 protocols and UHF radio communication links. Transfer options were analysed using measured primary feeder and secondary substation load and considered the effect of load transfer on the maximum demands at the adjacent primary substations. The design process then presented a range of options for consideration at workshops involving representatives from Asset Strategy and Network Control.

6.1.2.1 Key Learning

The key learning published in the reporting referenced in this section is set out below.

11kV interconnection:

- An initial theoretical maximum headroom increase of 16.9% for one trial area was reduced to 6% through the consultation process.
- An 11% headroom increase was achieved in the second trial area.
- In both cases, dynamic reconfiguration was considered unnecessary and permanent or seasonal reconfiguration was undertaken.
- A generalised CBA was carried out for two scenarios:
    - Using representative costs for upgrade of 33kV Primary Substation, an expenditure of £6,200k could be deferred for a minimum period of 8 years for an expenditure of £188k.
    - Using representative costs for deferral of 33kV transformer replacement, an expenditure of £600k could be deferred for a minimum period of 8 years for an expenditure of £188k.
- SPEN state that in their ED1 plan they have identified similar schemes where flexible network control can be implemented for approximately £95k, resulting in an increased financial benefit.

6.1.2.2 BAU Assessment

11kV Interconnection

The Flexible Networks project provides a strong evidence base of the potential for this solution to release network capacity and SPEN indicate a strong indication to deploy further within ED1. **BAU Score: 4.**

[20] Existing SCADA includes Central Control Units at Primary substations controlling up to 17 Network Control Points each.

6.1.3 WESTERN POWER DISTRIBUTION

In order to address voltage rise issues from DG and increase hosting capacity, the Low Carbon Hub project trialled an 'active network ring' by installing additional switchgear, dis-connectors, cables, new protection relays and the supporting telecoms infrastructure [52].

The FALCON project trialled meshing of 11kV radial networks by closing normal open points as an alternative to conventional upgrade [58]. The trial scope was reduced due to communication issues hampering the proposed protection arrangements. The final implementation closed the NOP of two 11kV feeders connected to one primary substation.

6.1.3.1 Key Learning

The key learning published in the reporting referenced in this section is set out below.

33kV interconnection:

- This method was deemed to be technically successful, allowing an additional generation connection and generally improving the network robustness - reducing network impedance and improving network resilience and availability.
- The solution is noted to be highly case-specific and there were many technical challenges encountered in the trial.
- The final CBA was not positive compared to other alternative solutions and is unlikely to be pursued further by the DNO.
- The cost of deployment was approximately £2m with an additional 5-8MVA capacity released.

11kV interconnection:

- The trial did not demonstrate any increase in capacity headroom.
- No significant changes were seen in circuit voltage or in power quality during mesh test periods.
- A 5% improvement in losses was calculated to have occurred.
- Network-specific modelling is required to assess potential benefit on any candidate network.
- The project considers that the trial findings demonstrate limited potential for this solution to release network capacity

6.1.3.2 BAU Assessment

<u>33kV Interconnection</u>

The Low Carbon Hub Trials provide strong evidence against the BAU adoption of 33kV ring interconnection. Although technically successful, with some benefit observed, costs were deemed to outweigh costs. WPD state that other solutions are preferable, but the solution could be revisited in alternative form. **BAU Score: -3.**

<u>11kV Interconnection</u>

The simple mesh trial of the FALCON project released no additional capacity and the project concluded there was little potential in this approach. However, other more complex proposed trials were not carried out and the theoretical potential for 11kV meshing is acknowledged. **BAU Score: -3.**

6.1.4 ENWL

The 'Bidoyng' Smart Fuse project provided a demonstration of an innovation developed under the IFI mechanism. The Smart Fuse contains two LV fuses in a standard size fuse carrier. It automatically inserts a secondary fuse into a circuit following a transient fault and hence enables much faster restoration of supply.

The solution was deemed to be at a high TRL and this project tested the feasibility of deploying a significant quantity of the devices (200 units covering 66 feeders).

The Low Voltage Protection and Communications Project [59] (LVPAC) tested the integration and remote control of low voltage circuit breakers and low voltage switches which can be retro-fitted to the LV network. The project deployed these devices in conjunction with a communications system that allowed integration with the ENWL SCADA system, facilitating the remote control of the devices and transfer of status and measurement data from the device. The enhanced communication and protection capabilities developed in this project provide a foundation that is to be built upon in the Smart Street project.

The Smart Street project is the full scale trial of previously developed monitoring, automation and voltage management functionality [60]. It is aiming for fully coordinated LV voltage management that includes network reconfiguration. The project is in progress at the time of this review and formal learning outputs are unavailable.

6.1.4.1 Key Learning

The key learning published in the reporting referenced in this section is set out below.

LV Protection and Automation:

- Initial results show a correlation between a reducing number of low voltage transient faults and an increasing use of the Smart Fuse; however, it is recognised that a longer period of analysis is required to draw firm conclusions on improvements to quality of supply.
- The Smart Fuse now provides an automated method of restoring supply after transient faults (80% of low voltage faults).
- The Smart Fuse provides network monitoring functionality. Analysis of monitoring data has determined that solar PV generation has not had any detrimental effect on voltage levels on the low voltage side of a case study transformer.
- The use of the Smart Fuse in Electricity North West is now written into an official code of practice - Fault Location Techniques for the LV Underground Network.
- The concept of LV circuit breakers and switches that can be remotely configured has been proven in a test network environment.

6.1.4.2 BAU Assessment

<u>LV Smart Fuse</u>

The Smart Fuse trials provide strong evidence for the BAU adoption of this enhanced LV protection. ENWL state that this technology has now been adopted as BAU. **BAU Score: 4.**

<u>LV Interconnection</u>

The LV-PAC project provides initial indications of the benefits of LV interconnection and automation. **BAU Score: 1.**

6.2 Discussion

Altering the network's operating configuration on a permanent or dynamic basis has been tested. Low Carbon Hub created a 33kV ring by closing the NOP of two feeders. The trial concluded that the benefits observed did not justify the significant deployment costs. The Flexible Networks project addressed the benefit of enhanced control of 11kV switches on secondary networks to dynamically transfer load between primary substations. The Flexible Networks project reported headroom increases up to approximately 17% and provided an illustrative CBA that indicate a solid business case. The findings from the FALCON project indicate no benefit to 11kV meshing; however, the trial was of a much simpler form than the Flexible

Networks trial and perhaps highlights that generalisation is difficult and benefits will require network specific analysis. UKPN and ENWL have developed significant LV interconnection and automation capabilities; however, assessment of the technology status and potential benefits depends on the outcomes of the FUN-LV and Smart Street projects.

6.3 BAU Overview

An overview of the BAU scoring is provided in Figure 13. The trials have provided a contrasting evidence base and, although some projects have settled on quite strong final positions, it appears that further trials and a wider evidence base would be of value. The SPEN trials of 11kV meshing indicate that this solution should be investigated further by all DNOs as a potential BAU option. Smart Fuse trials have provided strong evidence that the technology is a viable BAU option.

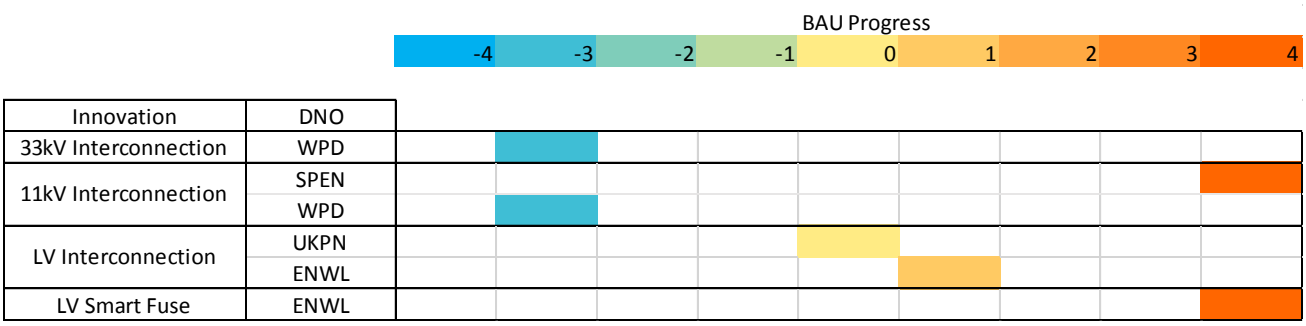


Figure 13: BAU Assessment for Network Configuration Projects

6.4 Synthesis of Learning

The synthesis of learning and associated recommendations derived from the review in this section are set out below.

Learning:

- In the cases assessed, interconnection at 33kV has been shown to have insufficient benefit to justify deployment.
- Interconnection between 11kV substations has been shown to have significant potential for cost-effective release of network capacity by the Flexible Network Connections project; however, some contrary evidence is provided by the FALCON project.
- Justification for interconnection and automation at LV has yet to be proven; however, significant projects in this area are yet to close and report fully.
- Smart Fuse technology for LV networks has shown significant potential and should be considered as a BAU option.

Recommendations:

- Further work on 11kV interconnection is carried out to enhance the evidence base and confirm the potential of the solution as a BAU option for all DNOs.

7 Synthesis of Learning on Equipment for Active Regulation of Voltage

The heat map identifies a high level of activity around the management and operation of equipment for active regulation of voltage on the distribution network. Traditional DNO voltage control is a largely passive process. Primary substation transformers employ Automatic Voltage Control and On Load Tap Changing (OLTC) functionality with a target voltage specified for the lower voltage busbar. From that point onwards, there is normally very little active control in the lower voltage distribution network. The network assets are designed to comply with a maximum voltage drop under worst case loading conditions that allows the DNO to comply with their quality of supply obligations [61, 62]. The LCNF projects contain numerous innovations that enhance the ability to control voltages throughout the entire distribution network.

The review considered:

- What new technologies have been deployed?
- What levels of benefit have been observed versus reinforcement?
- How close to BAU are the different technologies/methods?

The projects reviewed are shown in Table 18.

Title	DNO	Budget (£m)	Tier	Start Date	End Date
Customer Led Network Revolution	NPG	31	Tier2	Dec 10	Dec 14
Low Carbon Hub	WPD	2.8	Tier2	Dec 10	May 15
Voltage Control System Demonstration Project	WPD	0.53	Tier1	Mar 11	Mar 14
Voltage Management on Low Voltage Busbars	ENWL	0.49	Tier1	Apr 11	Oct 13
Flexible Plug and Play	UKPN	6.7	Tier2	Dec 11	Dec 14
Flexible Networks for a Low Carbon Future	SPEN	3.6	Tier2	Dec 11	Sep 15
Customer Load Active System Services	ENWL	7.2	Tier2	Dec 12	Sep 15
Low Voltage Integrated Automation	ENWL	0.6	Tier1	Jan 13	Jun 15
ETA (Smart Street)	ENWL	8.4	Tier2	Dec 13	Dec 17
Flexible Urban Network	UKPN	6.5	Tier2	Dec 13	Dec 16
Voltage Control System Integration - D-SVC Phase 2	WPD	0.9	Tier1	Dec 14	Jun 17

Table 18: LCNF Projects Testing Equipment for Active Regulation of Voltage

7.1 Project Details

In the following sections, the projects listed in Table 18 are reviewed, summarised and the key learning is identified

7.1.1 NORTHERN POWER GRID

The Customer Led Network Revolution project tested a range of network solutions designed to enhance network flexibility and increase capacity to accommodate LCT and DG penetrations. Solutions trialled included: on-load tap changing distribution transformers, flexible remote control of primary Automatic Voltage Control set-points, in-line voltage regulators at HV and LV, and shunt capacitance.

Extensive learning on design, specification, procurement, integration, logistics, installation and commissioning have been published [63]. However, in summary, the project reported that no major issues were encountered that existing DNO skills and process could not be adapted to deal with. The exceptions to this were the novel areas of extended communications and wide area control that presented new concepts and technology and required considerable amounts of supplier technical support. It was noted that LV Regulators have a large footprint once all components are integrated within a suitable container, hence availability of space will be critical in determining whether schemes are practical.

Enhanced AVC was trialled at two primary substations by adding a SuperTAPP n+ relay connected in parallel with the existing MicroTAPP relay. The primary transformer and OLTC remained in place. The additions allowed remote configuration of settings and integration with an area control scheme [63]. The published trial data is for a one day demonstration of the area control scheme coordinating the primary transformer AVC with a BESS device [64]. In the trial, responding to the system state estimator flagging an over-voltage violation in the downstream network, the area control requests a reduction in target voltage from the primary AVC. For the purposes of the trial the AVC target voltage range was limited artificially to force the area control to also call for a reactive power service from the BESS. The BESS absorbs reactive power, reducing voltage to the target level. As per the trial data published, the modelling extrapolation focussed primarily on the coordinated use of the primary transformer and the BESS. There are no 'AVC only' test results that allow an independent evaluation of the benefits of deploying only this technology at primary substations.

Two existing HV in-line regulators (3-phase brush transformers with Ferranti OLTC units) were also augmented with SuperTAPP n+ relays to allow remote configuration of settings and integration with an area control scheme. The HV regulator trials did not produce useful results, therefore results from the distribution HV/LV OLTC transformer trials were used to build a model for simulation studies of the HV regulator "*The trials of the HV regulators integrated with the GUS system were carried out during the months of July to September 2014. This is a period where the load, in the areas of network under investigation, was low in comparison with peak winter load. The robust nature of the trial networks coupled with this timing, resulted in data that does not easily enable validation of the GUS model from the closed loop GUS voltage control trials. In place of this, the results of the validation of the analysis of GUS with the HV/LV tapchanger are presented which interacts with the HV regulator in an identical manner"* [65] (page 2). As presented, the results indicate that extremely high penetrations of LCT were achievable on the test feeder without any additional voltage control. Application of the HV regulator increases that penetration to extremely unlikely levels (e.g. every customer having multiple ASHP, EV and PV). The additional evidence that this modelling provides regarding the HV regulator as a cost-effective solution to be deployed by DNOs is unclear.

An existing HV switched capacitor with two banks of three capacitors each controlled by a modern AVC relay and a Programmable Logic Controller (PLC) was also included in the trial and enhanced with the addition of a SuperTAPP n+ relay [66]. The same situation regarding results for HV regulator trials applies to HV switched capacitor results. The same approach of using OLTC trial data to build a model and simulate LCT penetration was taken. As a theoretical modelling exercise, the potential for additional legroom[21] of up to 11% was demonstrated.

Three distribution substations were upgraded with OLTC transformers. The project observed that distribution transformers with OLTC were, at the time of solution design, in very early stages of commercial availability. The supplier Maschinenfabrik Reinhausen was selected on the basis of being the only supplier at the stage of having a successful trials demonstration. The OLTC transformers were trialled in both local and coordinated control modes [67]. The target voltage for the trial period was 0.415kV (1.0375 pu). Various

[21] Capacity for further voltage drop before the minimum voltage limit is reached.

dead band and time delay settings were tested successfully. The trial results were used to build a validated model of the system to test LCT penetration limits. The test LV system had 146 customers.

The testing has highlighted challenges in accurately modelling this equipment at the LV voltage level. A trade-off between tap-change frequency and extra legroom was identified in the modelling.

Further modelling of the trial networks was undertaken to simulate the coordinated control of all voltage solutions [68]. Although the wide-area control system has been integrated with the multiple solutions and has been demonstrated in one-off simple control scenarios (coordinating at most two resources), no field demonstration results of prolonged coordinated wide-area control are published. With conclusions based primarily on simulation work, this project's system of coordinated voltage control appears to still be in early innovation stages of development.

7.1.1.1 Summary

A significant amount of equipment has been deployed in the above described trials. From the summary learning documents it is clear that the equipment was tested over a significant amount of time; however, from the trial analysis publications, it has been difficult to identify any learning above that taken from single day trial results with associated modelling extrapolation.

An overall 'Merit Order' strategy for voltage has been established by the project and it appears that the learning from these trials has shown that the equipment has been proven deployable and operates technically as expected; however, its application will depend on individual network requirements and CBA against asset upgrade to be assessed as LCT penetrations require.

The Merit Order [22] is summarised as:

1. Identify the issues
2. Address the thermal issues
3. For any remaining voltage issues
    I. Apply default 3% load-drop/generation-rise compensation setting on all active voltage control devices
    II. Carry out bespoke voltage setting analysis for increased load-drop/voltage-rise compensation settings and tighter dead-bands
    III. Where contracts permit, utilise controllable DG real and reactive power settings
    IV. Seek to contract flexible demand for both real and reactive power
    V. In urban areas, deploy OLTC at the secondary substation (if cost justified against LV cable overlay)
    VI. In rural areas, deploy HV regulators
    VII. Deploy area control to coordinate the set-points of voltage control devices (including constrained DG)
    VIII. Reinforce where required to close the remaining capability gap

The conclusion is that the existing primary substation AVC equipment would be augmented as a first option; however, all other equipment tested in this project would only be considered if other flexibility options to control real/reactive power were not available and then only if cost effective against asset upgrade. Deriving full value from the voltage control scheme (if deployed) also requires wide area coordination.

7.1.1.2 Key Learning

The key learning published in the reporting referenced in this section is set out below.

Primary substation enhanced AVC:

- In a local voltage control mode of a primary substation, which neglects the voltage at the end of HV feeders, the numbers of LCTs that can be accommodated is limited by the thermal rating of the transformer
- The coordinated use of EES and EAVC can reduce tap operations. Nominally, doubling the capacity of the energy storage can result in a 5% reduction in tap change operations
- BESS reactive power is more effective than real power for controlling voltage even in rural HV networks.

HV regulators:

- Extrapolation modelling tested ASHP, EV and PV penetrations for the test feeder. The feeder had 303 customers, of which 231 customers were domestic customers. Two LCT clustering approaches were tested: a) An LCT cluster spread across HV feeder, b) An LCT cluster wholly downstream of regulator.
- The baseline air-source heat pump penetration with no intervention was a) 478 and b) 344 units. Application of the HV regulator in various control modes allows an increase in the order of 300%.
- The EV penetration baseline is a) 2309 and b) 1803 units. Application of the HV regulator in various control modes allows an increase in the order of 200%.
- The PV penetration baseline is a) 917 and b) 734 units. The HV regulator alone cannot facilitate additional penetration without adding additional tap settings

Secondary substation OLTC:

- Extrapolation modelling tested LCT penetrations for an LV system with 146 customers
- The LV regulator releases 1.5% additional headroom[22]
- An LV OLTC releases 8.7% additional headroom and 7.4% additional legroom
- The air-source heat pump penetration baseline with no intervention is 73 units. Application of the distribution OLTC in various control modes allows an increase in the order of 80%.
- The EV penetration baseline is 276 units. Application of the distribution OLTC in various control modes allows an increase in the order of 250%.
- The PV penetration baseline is 75 units. Application of the distribution OLTC in various control modes allows an increase in the order of 40-80%.

Coordinated voltage control:

- Coordinated control enabled increased accommodation of LCT cluster penetrations
- A particular benefit stated was the ability to extend the impact of solutions such as BESS from a local issue to a wider network area. For example, BESS located on HV feeder in coordination with primary tap change AVC was shown to solve voltage rise issues on one feeder and voltage drop issues on another.

7.1.1.3 BAU Assessment

<u>Enhanced Primary AVC</u>

The CLNR project demonstrated improvements that can be made to existing primary substation AVC methods in the context of a centralised control architecture. Although the technical evidence implies benefits can be derived here, the reliance on a shift to a control architecture that is currently deemed by the project as too complex and unnecessary for current needs, presents a major uncertainty. **BAU Score: 1.**

[22] Capacity for further voltage rise before the maximum voltage limit is reached.

Secondary Substation OLTC

The trials of OLTC at secondary substations have provided a good evidence base that significant voltage headroom and legroom can be released in a local control mode. Further improvement can be achieved if the solution is adopted into an area control scheme. The technology is still very new and the CBA versus LV cable re-lay is unclear at this time. The benefits have been analysed with respect to future, high LCT penetration scenarios. **BAU Score: 2.**

Voltage Regulators and Capacitors

The CLNR trials provide an inconclusive evidence base for voltage regulators and switched capacitors.
BAU Score: 0.

7.1.2 UK POWER NETWORKS

The Flexible Plug and Play project [51] tested voltage control solutions with respect to DG connections at 33kV and 11kV. Existing Grid Supply Point (GSP) and primary substation AVC was enhanced by deploying SuperTapp n+ relays and linking to an ANM platform. The objective of the project was to prove the concept of using a centrally located ANM system to monitor the impact of the distributed generation in the network and send an optimum voltage target and optimum load ratio to the remote AVC relays.

For the 33kV application, the ANM system calculated optimum voltage targets for the grid substation by comparing transformer and feeder measurements with remote measurements at the Point of Common Coupling (PCC) at a number of DG sites. For the 11kV application a load ratio was determined dynamically using remote measurements from PCCs at a number of generation sites.

The project close-down report refers to a detailed report on trial findings; however, this could not be found in the referred location during this review. The context of this trial has been to develop ANM voltage control functionality with respect to DG connection. The published results are primarily technical proof of concept rather than examining a detailed business case.

7.1.2.1 Key Learning

The key learning published in the reporting referenced in this section is set out below.

Enhanced AVC:

- Trial results verified pre-trial simulation findings that generator export affects LDC functionality and introduces power factor deviations.
- When compared to simulation results, the new method was shown to improve accuracy over the standard method.

7.1.2.2 BAU Assessment

Enhanced Primary AVC

The Flexible Plug and Play project demonstrated improvements that can be made to existing AVC methods in the context of DG connection. Although the technical results were positive, the new method relies on a centralised ANM system, and hence adoption to BAU relies on a shift in strategy to a centralised control architecture. Major uncertainty remains around the business case. **BAU Score: 1.**

7.1.3 WESTERN POWER DISTRIBUTION

The Voltage Control System Demonstration Project [69] investigated the voltage control of an 11kV rural feeder with a 1.8MW windfarm 4.3km from the primary substation on a mixed underground/overhead feeder (predominately constructed of overhead lines (OHL)). The solution tested was a D-STATCOM

(supplied by Hitachi), connected at 11kV through a transformer. Under/over voltage protection was deployed at the site. A phase 2 project has just commenced for coordination of D-STATCOMs.

The Low Carbon Hub project undertook a variety of network solution trials. This involved shunt compensation through the use of a D- STATCOM FACTS device [70]. In this trial a D-STATCOM was installed at a primary substation served by two lines (26.2km and 26.3km) from the grid substation. The unit comprises of three 1.25MVA inverters installed in a container along with control hardware and HMI. The container dimensions are 8.23m x 2.81m x 3.1m. Network connection is made via a 5MVA, 480V to 33kV transformer.

The Low Carbon Hub project trialled dynamic setting of primary substation AVC voltage targets [52]. The existing Automatic Voltage Control of a primary substation was augmented by taking remote real time voltage measurements to the control room NMS, applying voltage control algorithms and issuing target voltage settings to the transformer. A new SuperTapp n+ relay was installed and a method of using 11kV side VT to calculate primary side voltages was developed.

Results and performance of the trial are very sparse in the close down report and associated documents. The reporting indicates that extensive offline testing of the voltage control algorithm was undertaken. There are references to a 'reluctance to move from hardwired control' and a summary statement that "*when a robust method of Dynamic Voltage Control has been demonstrated and applied in appropriate areas, the Cost Benefit Analysis will be high".* From this it is inferred that the voltage control solution was not successfully demonstrated by this trial.

The CBA statement describes an approximate cost of £100k with a zero MVA capacity benefit. However, there is a strong expression that this solution still has significant potential and an interest should be pursued further. Mention is made of operation in conjunction with an ANM scheme – the implication is that dynamic voltage control reducing voltage constraints combined with ANM to curtail generators is more viable than standalone dynamic voltage control.

7.1.3.1 Key Learning

The key learning published in the reporting referenced in this section is set out below.

D-STATCOM:

- Voltage Control System Demonstration Project:
  - Although the basic functionality was proven in the trial, the level of voltage control realised was below the anticipated levels.
  - It was observed that the transformer selected needs to have a HV voltage metering unit to ensure that appropriate protection can be fitted and get visibility for the HV voltages and power from the D-STATCOM.
  - The project also successfully integrated the unit to the ENMAC NMS. Although local in operation, observation was deemed necessary at the control room.
- Low Carbon Hub:
  - When the D-STATCOM is operating at 100% capacitive mode (exporting reactive power) the voltage at the POCC is boosted by 3%.
  - When the D-STATCOM is operating at 100% reactive mode (importing reactive power) the voltage at the POCC is reduced by 5%.
  - The D-STATCOM can operate at 263% of the nominal output (3.75MVAr) for two seconds in the event of a network disturbance.
  - Overall, the project deemed the D-STATCOM 'very effective' at controlling network voltages.

- The CBA analysis indicated approximate cost of £775k for additional capacity of 15MVA; however, this is noted to be very case specific dependant on location of DG.
- Although trials were positive, issues around costs, noise and suitable planning tools have been identified. Future use will depend on the resolution of these issues and the network-specific need cases that arise.

7.1.3.2 BAU Assessment

Enhanced Primary AVC

The Low Carbon Hub project provided inconclusive evidence on the value of this solution. The reliance on a move to an as yet unknown centralised control architecture is a major uncertainty. **BAU Score: -1.**

D-STATCOM

The WPD trials provide a solid base of early experience with D-STATCOM devices. The technical case appears to be strengthening; however, issues around costs and deployment practicalities continue to create major uncertainty on the business case for this innovation. **BAU Score: 1.**

7.1.4 ELECTRICITY NORTH WEST

The Voltage Management on LV Busbars project aimed to gather experience in the deployment of technology not normally used on LV networks and to undertake improved modelling to assess their potential [71]. To test distribution (Secondary) substation OLTC (D-OLTC), two Maschinenfabrik Reinhausen prototype units were installed at two distribution substations in parallel with existing transformers. The relay used was the Reinhausen TapCon 230. Two 'powerPerfector Plus' voltage regulation units[23] were deployed on two LV feeders with high PV and zero PV penetration respectively. Testing of LV capacitors were planned; however, issues related to deployment prevented a successful trial and publication of results. Modelling extrapolation indicated a 250kVar Capacitor bank installed at the feeder midpoint could increase loading capacity in the order of 70%.

The Low Voltage Integrated Automation (LoVIA) project built on the outcomes of previous LV monitoring and voltage management projects. LoVIA implemented secondary substation OLTC for voltage control in two LV networks with an approximate PV penetration of 30%. Measurements from the LV feeders were fed back to a bespoke network management system that implemented a voltage control algorithm and adjusted the OLTC target voltage [72]. The TapCon230 relay was used and relevant parameters settings were: bandwidth 2.2%, tap delay 120 seconds, LoVIA control cycle se to 30 minutes. The costs for deployment of the solution at two sites is estimated at around £450k.

The Smart Street project is the full scale trial of previously developed monitoring, automation and voltage management functionality [60]. It is aiming for fully coordinated LV voltage management that includes reconfiguration, D-OLTC and shunt capacitors. The project is in progress at the time of this review and formal learning outputs are unavailable. It is noted that the outputs of this project should be expected to provide significant insight into the business case for the concept of a fully visible, automated LV network.

The CLASS project [47] has been reviewed in the Flexible Demand section of this report. Although it is primarily positioned as a demand reduction solution, it has been included in this section as the method to achieve demand reduction is enhanced voltage control at primary substations. The trials deployed autonomous substation controllers (ASC) at 60 primary substations. The ASC was activated centrally by the control room Network Management System (NMS) then operated in conjunction with the existing AVC relay to provide On Load Tap Change (OLTC) functionality. For ten sites the ASC was also able to trip one of the

[23] *powerPerfector Plus is a 3-phase low voltage technology that allows voltage boost or buck functions similar to an autotransformer*

primary transformers circuit breaker, reducing voltage due to the increase in impedance. The ASCs were also linked to the System Operator NMS via an (Inter-Control Centre Communications Protocol) ICCP link.

7.1.4.1 Key Learning

The key learning published in the reporting referenced in this section is set out below.

Secondary substation OLTC:

- Voltage Management of LV Busbars:
  - Monitoring of the D-OLTC indicated that at both sites the tap changers had performed approximately 80 times in a 3 month period.
  - It was noted that some causes of tap change actions were occurrences of over voltage (>253V) at night.
  - Modelling extrapolation indicated that loading capacity of the trial network could be increased by 87% using DOLTC. With a high PV penetration this additional capacity could be almost doubled.
- LoVIA:
  - Monitoring data during the summer and autumn of 2014 indicates voltages at all mid and end points of the LV feeders were within the statutory limits.
  - 1.4 and 1.9 tap operations per day were observed on average for the two networks.
  - Modelling indicates that the LoVIA approach can increase PV penetration from 30% to 50%.
  - A comparison with a scheduled Time Based Control approach, shows similar benefit; however, LoVIA requires less tap operations.

Voltage regulator:

- Monitoring results verified the successful operation of buck and boost functionality.
- Modelling extrapolation indicates increased feeder loading capacity of 32%.

Voltage reduction:

- A 1% voltage reduction at a primary substation produces a seasonal average real power reduction in the range of 1.3% - 1.36% and an average seasonal reactive power reduction of 5.54% - 5.83%.
- The evidence presented by the report indicates that a general voltage reduction of 1.5% at primary substations is feasible and is a cost-effective method to unlock existing capacity in the network.
- Although the primary application in the CLASS trials was for demand reduction, the solution could equally be used for voltage management e.g., enabling increased voltage headroom for distributed generation.

7.1.4.2 BAU Assessment

<u>Voltage Reduction</u>

The technical and commercial evidence for Voltage Reduction is strong. ENWL indicate strong intentions to pursue the solution. Some further trial work and upgrade of primary substation equipment to enable roll-out has been identified for ED1. **BAU Score: 3**.

<u>Secondary Substation OLTC</u>

The trials of OLTC at secondary substations have provided a good evidence base that significant voltage headroom and legroom can be released in a local control mode. Further improvement can be achieved if the solution is adopted into an area control scheme. The technology is still very new and the CBA versus LV

cable relay is unclear at this time. Benefits have been discussed with respect to future LCT penetration. **BAU Score: 2.**

Voltage Regulators

The technical proof of concept for LV regulators provides early indications of benefit for LV voltage management, however the business case is not examined and the project recommends further trials. **BAU Score: 1.**

7.1.5 SCOTTISH POWER ENERGY NETWORKS

The Flexible Networks project focussed on the challenge of releasing existing capacity with quickly realisable solutions [73]. The high level objective was to achieve a nominal target of 20% increase in capacity and hence provide short term flexibility. The solutions reviewed in this section are flexible network control enhanced with voltage regulators and voltage set point optimisation.

Automatic Voltage Regulators (AVRs) underwent extensive testing prior to a trial deployment [74]. Although not a new technology for the DNO, the solution was seen as an enabler for network reconfiguration, i.e., network reconfiguration releases capacity for new demand, but causes voltage excursions. The project reports that policy, processes and procedures have been developed for implementing AVRs as BAU going forward. A generalised CBA compares a generic cost of £225/kVA for 11kV reinforcement to the £87/kVA derived from an estimated £122,000 cost for a pair of AVRs to release a theoretical 1400 kVA in the project area.

A voltage set-point optimisation trial aimed to test the benefits of a voltage reduction at primary substations in relation to increased headroom for distributed generation, specifically PV [75]. A voltage reduction of 3% was applied at a primary substation in the trial area for the majority of January 2014. Monitoring from secondary substations and smart meters was used to determine the impact. Analysis of LV busbar voltages for substations with both high and low PV penetrations suggest that variations in loading of the LV network due to PV generation, or demand, do not influence LV busbar voltage significantly. Instead the LV voltage is mostly dictated by upstream HV busbar voltage. The project observed that in order to enable greater PV uptake and reduce voltages in general, there is a case for voltage reduction. It is noted that in general there is about 6% legroom on typical LV networks; however, Grid Code OC6.5.3 obliges DNOs to reserve capacity for up to 6% voltage reduction to support the transmission system in very rare events such as unexpected loss of large generators. Revision of this obligation would enable the DNOs to be more flexible in their optimisation of voltage.

SPEN have committed to a significant asset replacement programme in ED1 that will upgrade the voltage control relays at primary substations – a pre-requisite for this method to move to BAU. Moving towards BAU, SPEN currently believe that a 2% voltage reduction is possible; however, this require a wider pilot to increase confidence and gauge the extent of isolated under-voltage issues.

7.1.5.1 Key Learning

The key learning published in the reporting referenced in this section is set out below.

Automatic Voltage Regulators:

- AVRs as an enabling technology for flexible networks is justified.
- Tools have been developed for modelling the network to select the best location for the voltage regulators.
- The process of installing AVRs has been formalised with a standard four pole supporting structure being developed along with installation guidelines.

- Telecontrol functionality for the voltage regulators has been developed and the control rooms in both SPD and SPM have implemented processes to ensure that the units operate safely when connected to parallel networks.
- The issues around installing AVRs for generation connections are more complex than previously thought – SPEN policy on this application of AVRs is under review.

Voltage Reduction:

- For the trial network the main conclusion is that a 2% reduction in voltage enables a further 90% of PV generation by kW to be connected.
- Analysis of voltage/demand relationship is noted to be highly dependent on many factors such as network area, load types, season and more.
- In the absence of local knowledge or experimental results, a reduction of 1% in active power demand in response to a 1% voltage reduction is a reasonable estimate and this also typically corresponds to a 1% reduction in energy use by consumers.
- A CBA of the method versus traditional costs indicates a reduction to £31,000 from £53,700[24].
- Additional carbon benefits and social benefits are estimated at £12,686 and £27,400 respectively.

7.1.5.2 BAU Assessment

Voltage Reduction

The technical and commercial evidence provided by SPEN for this solution is strong. SPEN indicate intentions to pursue the solution. Some further trial work and upgrade of primary substation equipment to enable roll-out has been identified. **BAU Score: 3.**

Voltage Regulators

The Flexible Networks trials provide evidence that HV regulators provide significant technical benefit as an enabler for flexible network configuration and generation connection. The solution has been moved into BAU by SPEN; however, further work is required to define policy regarding the application for generation connection. **BAU Score: 3.**

7.2 Discussion

The technologies reviewed have been grouped into common technical categories and are discussed below.

7.2.1 Transformers

Voltage Reduction

Upgrading the functionality for the control of primary substation transformer tap-settings allows the concept of voltage reduction to be tested. This was the focus of the CLASS and Flexible Networks projects. Both reported a good degree of success with potential for significant benefits in load reduction and additional distributed generation hosting capacity (PV). Specific results and approaches vary between the projects, as do opinions on the merits of seasonal voltage management; however, voltage reduction in the range of 1% to 3% is deemed appropriate. Review of Grid Code OC6.5.3 is noted as necessary if this approach is to be widely adopted.

Primary Substation Enhanced AVC

The CLNR, Flexible Plug and Play and Low Carbon Hub projects all undertook work to enhance the existing functionality of Automatic Voltage Control of transformer tap-settings at Primary Substations via upgrading

[24] Using a typical cost of £150/kVA for LV reinforcement the base cost of the capacity released in this project area is 358kVA x £150/kVA = £53,700

relays and adding substation control capabilities. In addition to local operation, centralised operation was tested. The enhanced systems provided a range of remote measurements that fed centralised control systems implementing voltage control algorithms that sought to optimise voltage targets at the substations under control. Learning objectives centred on proving the concept as a building block of control functionality. The business case for deployment is intrinsic to a wider case for coordinated area control rather than a stand-alone solution.

Secondary substation OLTC

Introducing voltage control functionality to secondary substations (transformers with on load tap changing) was tested by the CLNR and project and ENW's Tier 1 "Low Voltage Management on LV busbars" and LoVIA. The deployments provide field testing experience of both local and centralised control modes. Learning objectives focussed on gaining experience of deployment and demonstrating operation as expected. Further modelling was then undertaken to assess the potential for additional LCT hosting. Even without the optimisation of centralised control using network measurements, the modelling results indicated a range of improvements to LCT hosting capacity upwards of 50%.

Voltage Regulators

CLNR tested controllable regulators both at HV and LV, and Flexible Networks undertook detailed analysis of HV regulators. From the trial results presented, LV regulators appear to have limited benefit and major practical issues around installation. Flexible networks present field trial results for HV regulators that indicate benefit in releasing capacity. The CLNR business case for regulators is linked to the case for a wide area coordinated control scheme, where the regulators may offer an additional point of control.

7.2.2 Reactive Power Devices

Switched Capacitors

CLNR tested controllable capacitors both at HV and LV, and ENW's voltage management project tested LV switched capacitors. None of the trials reported field test results. Modelling extrapolation indicated potential benefit as part of a wide area coordinated control scheme.

D-STATCOM

WPD tested distribution STATCOM devices in a Tier 1 project and then undertook more advanced testing within the Low Carbon Hub project. Although trials were positive, issues around costs, noise and suitable planning tools have been identified. Future use will depend on the network specific need cases that arise and the resolution of these issues.

7.3 BAU Overview

An overview of the BAU scores is provided in Figure 14. The upgrade of voltage control functionality at primary substations appears to have an immediate application to voltage reduction. There are some barriers remaining to general roll-out of voltage reduction; however, a strong evidence base is building for the value of this approach. Although the application of further enhanced control functionality at primary substations (beyond a general or seasonal voltage reduction) is dependent on a wider shift to area or centralised control, the functionality should be included in a BAU upgrade of primary substation voltage control functionality. Secondary substation OLTC has some initial good evidence of value but further evidence is required to consolidate the business case. Considerable further work is required to provide sufficient evidence for HV/LV Regulators and Switched Capacitors. A large amount of voltage management kit has been tested across the UK networks. The various technologies have been tested technically with a range of results reported; however, realising their full potential appears to depend on a sophisticated degree of coordinated control across the network and they are hence unlikely to progress rapidly towards BAU.

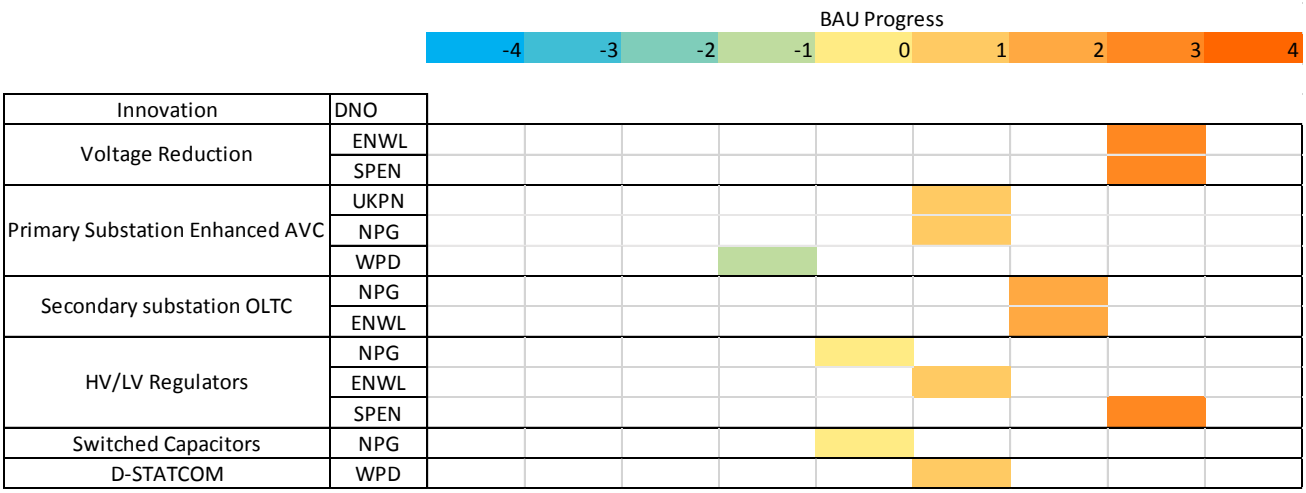


Figure 14: BAU Assessment for Equipment for Active Regulation of Voltage

7.4 Synthesis of Learning

The synthesis of learning and associated recommendations derived from the review in this section are set out below.

Learning:

- Voltage reduction at primary substations has been demonstrated as an effective method of releasing 'headroom' capacity that can also, depending on the nature of the load, potentially reduce energy consumption. This should be considered as a BAU option by all DNOs (revision of grid code stipulations may be required).
- Suggested approaches to voltage reduction vary between DNOs:
  - A permanent reduction of 1%;
  - Seasonal reduction up to 3%;
  - Local control by Load Drop Compensation up to 3%;
  - Coordinated control by a wide area control scheme.
- Dynamic control of voltage reduction has been noted to open the possibility of DNO provision of balancing services to National Grid.
- Enhancing automatic voltage control (AVC) functionality for primary substations via relay upgrade, additional control capability and enabling remote configuration, allows improved local control and is a key enabler for area coordinated voltage control.
- Deployment of secondary substation OLTC has been shown to release significant 'legroom'; however, there is debate on whether a positive CBA can be built versus LV re-cabling[25].
- HV Automatic Voltage Regulators (AVRs) are a useful enabling technology for flexible networks.
- D-STATCOM devices have demonstrated effective voltage control; however, issues are reported around costs and practical aspects of implementation.
- Results indicate the coordinated control of multiple voltage management devices across the network enables full value (increased network capacity) to be realised; however, this has only been partially demonstrated and is deemed difficult and too complex at present.
- The deployment of many controllable devices at all voltage levels requires coordination via area control schemes. The previous statement on complexity and necessity of such schemes, plus outputs on voltage management strategy by projects, indicate that although some of this voltage

[25] Although some additional footprint requirements were noted in the trial installations, secondary OLTC transformer sizes have not been highlighted as a barrier to deployment by these projects.

control equipment may be deployed in isolated, case-specific circumstances, limited additional control will be deployed beyond primary substations in the foreseeable future.

Recommendations:

- There is an opportunity for further knowledge sharing and collaborative efforts to establish best practice for voltage reduction. This should include further detailed technical work on associated issues including trends in the voltage dependency of loads, circulating currents and relay hunting.
- Additional to any upgrades required to deliver voltage reduction, enhanced voltage control functionality for primary substations should be considered as a standard deployment as a key enabler for future voltage control strategies.
- Innovation work should focus on proving/improving the business case of secondary substation OLTC against LV reinforcement.
- There is an opportunity for further knowledge sharing and collaborative efforts to establish best practice for HV Automatic Voltage Regulator applications.
- Further innovation in respect of voltage regulation should focus on the required coordination and control architectures (boundaries between local and centralised control, and coordinated management of thermal and voltage constraints) rather than being approached solely from a kit-testing perspective.

8 Synthesis of Learning on Real Time Thermal Ratings

The heat map identifies a high level of activity on the topic of real-time thermal ratings (RTTR) of network assets.

The review considered:

- What methods for RTTR have been applied to which assets?
- How accurate and reliable are these methods deemed to be?
- What has been learnt on the potential for RTTR to unlock network capacity?

The project register identified the following relevant projects (Table 19).

Title	DNO	Budget (£m)	Tier	Start Date	End Date
Implementation of Real-Time Thermal Ratings	SPEN	0.5	Tier1	Jul 10	Jul 13
Customer Led Network Revolution	NPG	31	Tier2	Dec 10	Dec 14
Low Carbon Hub	WPD	2.8	Tier2	Dec 10	May 15
Flexible Plug and Play	UKPN	6.7	Tier2	Dec 11	Dec 14
Flexible Networks for a Low Carbon Future	SPEN	3.6	Tier2	Dec 11	Sep 15
FALCON	WPD	12.4	Tier2	Dec 11	Sep 15
Temperature Monitoring Windfarm Cable Circuits	SPEN	0.7	Tier1	Oct 12	Mar 15
Power Transformer Real Time Thermal Rating	UKPN	1.5	Tier1	Jun 14	Dec 16
Combined On-Line Transformer Monitoring	ENWL	0.7	Tier1	Sep 14	Sep 16

Table 19: Real Time Thermal Rating Projects

8.1 Current Practice

There are a set of industry standards which set out the static ratings of a range of assets: ER P15 for Transformers, ER P17 for underground cables and ER P27 for overhead lines. The standards are based on mathematical models which predict conductor temperature under various conditions. OHL ratings can either be deterministic or probabilistic based on an understanding of the probability of weather patterns. ER P27 is a probabilistic standard, in that a static rating is determined via probabilistic analysis. This type of rating anticipates that the actual temperature of the line will only very rarely exceed the maximum thermal limit. The LCNF projects above include work to assess the validity of existing standards and work to move towards a more dynamic, real-time approach to asset rating.

8.2 Project Details

In the following sections, the projects listed Table 19 are reviewed, summarised and the key learning is identified

8.2.1 SCOTTISH POWER ENERGY NETWORKS

In the Implementation of Real-Time Thermal Ratings project, SPEN deployed a RTTR system that covers more than 90km of 132kV overhead line in the North Wales distribution network [76]. The system was integrated within the SPEN NMS as a discrete module. The method used a meshed network of weather stations and a geographical model for Thermal State Estimation (TSE) in real-time (every 5 minutes). A limited number of

conductor temperature sensors were used to validate the RTTR. IEC TR61597 and CIGRÉ WG22.12 standard-based algorithms were combined with thermal state estimation techniques to calculate overhead line RTTRs, based on weather data. In designing the system the project utilised research at Durham University suggesting that a maximum distance of 10km between meteorological stations is required. Station installation at all 132kV substations plus additional intermediary sites were undertaken to comply with this. 10 stations were installed in total. Direct conductor temperature measurement was also deployed to verify the system and increase control room confidence in this trial deployment. The RTUs at the meteorological stations measured wind speed, wind direction, ambient temperature and solar radiation with a sampling rate of 7.5 seconds. Every forty samples (5 minutes), the RTUs calculated maximum, minimum, average and standard deviation values and transmit to the NMS module for calculation of both deterministic and probabilistic RTTRs. The majority of 132kV substations had fixed line communication links. Additional sites utilised GPRS communications links. These encountered reliability issues.

Illustrative CBA for RTTR of 132kV OHL

Reinforcement (refurbishment) of existing 132kV single circuit: NPV = £3,009,488

Existing 132kV single circuit + RTTR: NPV = £433,988

The above figures include an indicative Capex cost of the RTTR system as £190,300 and an indicative annual O&M cost as £3,825.

In the Temperature Monitoring of Windfarm Cable Circuits project, SPEN trialled a Distributed Temperature Sensing (DTS) technology to monitor the real-time temperatures and calculate the dynamic thermal ratings of three 33kV cable windfarm circuits in Lanarkshire, Scotland [77]. The three underground cables, connecting to a 275/33kV substation shared a trench. The cables were rated at 32.2 MVA based on a maximum operating temperature of 78°C. The DTS system utilised optical fibres laid concurrently with the cables and measures temperatures at 30-minute intervals for every 1m of the optical fibre. Dynamic cable rating algorithms utilised the temperature monitoring and also ran every 30 minutes. The DTS system was validated by deploying additional independent temperature measurements. SPEN plan to conduct a new project under the NIA funding mechanism to prepare DTS and DCR systems for full business adoption.

Scottish Power's Flexible Networks project contained a work package on dynamic thermal ratings for 33kV overhead lines and primary transformers.

The 33kV OHL trial built on the previous SPEN RTTR trial at 132kV in North Wales. A section of 33kV line between Cupar and St Andrews was selected for RTTR trials [78]. The GE line monitoring system included pole mounted weather stations, solar panels, RTUs and line current/temperature sensors.

The additional functionality for this trial was:

- Line sensors to directly measure the temperature of the conductors.
- A conductor temperature estimation algorithm based on meteorological measurements, rather than only estimating thermal capacity.
- Validation of the RTTR model through comparison between calculated and monitored conductor temperatures.
- Enhanced accuracy and reliability of RTTR by increasing the number of weather stations.
- Development and implementation of a graceful degradation algorithm in SPEN's Network Management System.

Generalised CBA for 33kV OHL

For a hypothetical case of wind farm connection to a 33kV line:

Traditional cost of upgrading 17km of 33kV line = £1,270k.

RTTR system plus ANM to control windfarm = £140k.

Adding forecasting is seen as an essential next step to improve RTTR functionality and is currently part of a SPEN NIA project. Further work is also required on the integration of RTTR and ANM systems to achieve the potential costs savings outlined above.

The RTTR results are summarised in Figure 15 below.

	Circuit 1	Circuit 2
	Summer Season	
Maximum RTTR	669.2 A (11/08/14 5:05)	729.8 A (1/05/14 19:10)
Average RTTR	398.5 A	399.3 A
Minimum RTTR	155.3 A (25/07/14 14:00)	153.8 A (25/07/14 15:25)
Additional Energy Yield[1]	12.6 GWh	13.6 GWh
Curtailed Energy[2]	2.1 GWh	2.8 GWh
% time RTTR above static rating	68.4 %	59.3 %
Maximum Load/RTTR ratio	83 %	64 %
Most frequent critical span	pole 1 – pole 2	pole 50 – pole 51
	Winter Season	
Maximum RTTR	786.86 (23/02/15 14:15)	879.11 (1/03/15 3:30)
Average RTTR	484.92	468.73
Minimum RTTR	261.24 (17/10/14 14:05)	271.40 (8/10/14 11:40)
Additional Energy Yield[1]	12.6 GWh	11.1 GWh
Curtailed Energy[2]	3.9 GWh	5.3 GWh
% time RTTR above static rating	63.4 %	56.1 %
Maximum Load/RTTR ratio	87.9 %	95.4 %
Most frequent critical span	pole 1 – pole 2	pole 50 – pole 51

Figure 15: Flexible Networks Overhead Line RTTR results – reproduced from [78]

Primary transformer ratings were also considered by the Flexible Networks project. DNV GL undertook condition assessment of transformers in the trial area and then used their dynamic rating tool with historic data and future load scenarios to assess the potential benefits of RTTR for the transformers [79]. The results from the project led SPEN to conclude that dynamic rating is not required and instead more detailed bespoke studies can determine an enhanced rating that will allow capacity to be released. A Transformer Loading Tool developed under the project enables historic loading profiles and site specific ambient temperatures to be used to determine the 'Enhanced Rating' for a primary transformer. The new Enhanced Rating process is being introduced into current business practice.

Two generalised scenarios were used for business case assessment.

Business Case Scenario 1

A primary substation reaching capacity where existing transformers are already at maximum size standardly deployed[1].

New substation build = £6,200k and 3 years construction time.

Enhanced Ratings = £30k for 8 year deferral.

Business Case Scenario 2

A primary substation reaching capacity where existing transformers could be upgraded.

Transformer replacement = £600k

Enhanced Ratings = £30k for 8 year deferral.

8.2.1.1 Key Learning

The key learning published in the reporting referenced in this section is set out below.

132kV OHL:

- Data from the nine-month trial period showed average uplifts ranging from 1.27 to 2.19 times the static summer rating
- The potential average additional annual energy throughput ranged from 10% - 47% for the circuits considered.
- The project also demonstrated potential for increased wind generation potential in that there was a high correlation between local wind farm outputs and RTTRs of the overhead lines.
- Some high level CBA work around the project results demonstrated RTTR potential as a cost effective method of reinforcement deferral.

33kV OHL:

- For this trial, an additional network carrying capacity of around 11% (average of both circuits) can be unlocked by deploying the RTTR system.
- The trial compared RTTR calculations based on one weather station versus multiple stations, finding that it is very likely for RTTR to be overestimated if only one weather station is used as the effect of wind sheltered areas may be neglected. This demonstrates the importance of identifying micro climates and targeting weather stations accordingly.
- Results highlight occasions when solar radiation and ambient temperature are higher than those in ER P27, and therefore the RTTRs are actually lower than static rating.
- It is noted that for this trial area load is inversely correlated with ambient temperature. However, although cooler temperatures could be expected to cool OHLs the impact of variable wind speed on conductor temperature results in no strong correlation between RTTR and load levels.
- For model validation, the average absolute differences between calculated and measured temperature in the results presented are around 0.9°C. Differences are noted to be usually within the equipment accuracy range.

33kV Cables:

- The project reports that the DTS system is accurate and has potential to be deployed on wind farm circuits with appropriate power flow management functionality.
- Results showed that for 80% of the time the LLF of the cable circuits can be below 0.5 suggesting a dynamic rating is appropriate.
- No long term comparison is made of how the dynamic rating compares against a static rating.

Primary Transformers:

- A study for one of the primary substations (St Andrews) concluded that peak loadings could be increased above nameplate rating by 30% while maintaining an expected technical lifetime of 40 years. However, other asset limitations reduced the possible uplift to 14%.
- The other trial area studied comprised 3 single transformer substations. A variety of outage conditions were studied and a general conclusion reached that the firm capacity of this substation group could be increased by 10%.

8.2.1.2 BAU Assessment

132kV OHL RTTR

The evidence from the SPEN 132kV OHL RTTR trial indicates a good business case for BAU; however, the level of uplift in ratings is modest. **BAU Score: 3.**

33kV OHL RTTR

The Flexible Networks trials provides a solid evidence base for adoption of the 33kV OHL solution as a BAU option in conjunction with ANM schemes for DG connection. **BAU Score: 4.**

Primary Transformers

The Flexible Networks trials demonstrate that considerable benefit can be achieved; however, the project indicates that bespoke static ratings may be more appropriate. Further work is required to develop this solution and reduce the significant uncertainties. **BAU Score: 1.**

8.2.2 NORTHERN POWER GRID

In the NPG CLNR project, Real Time Thermal Rating methodologies were developed and trialled for underground cables, overhead lines and transformers over a period of approximately 9 months that included peak winter and summer periods.

The RTTR work for underground cables covered EHV (33kV), HV(11kV) and LV in a dense urban environment [80]. The methodology utilised the CRATER[26] model and required the following inputs:

- Cable size and type, installation configuration (cable laying formation)
- Soil ambient temperature
- Soil thermal resistivity and cable backfill material thermal resistivity if used
- Real time loading

A standard design process produced a static rating based on ER P17 and CRATER methods. With real time measurements the cable RTTR was calculated for comparison with the static ratings (Table 20).

[26] A cable rating tool developed by EA Technology Ltd.

	ER P17	CRATER	RTTR Summer Worst
EHV Steady state rating (Amps)	487	455	321
HV Steady state rating (Amps)	323	318	230
LV Steady state rating (Amps)	n/a	476	464

Table 20: CLNR RTTR for Underground Cables Results

This CLNR RTTR trial tested EHV and HV OHL in a rural low density area [81]. The RTTR model developed was based on CIGRE WR 22.12: 1992. This method was chosen due to being based on the same experimental work as ER P27. The key inputs are the wind speed profile and the ambient temperature. RTTR equipment was installed on two twin-circuit EHV towers and four monitoring devices were installed on a wood-pole HV line.

The CLNR Transformer RTTR trial tested 2 primary substations and 21 distribution substations [82]. The methodology calculated the ratings based on the equations set out in IEC 60076 using measured transformer load, ambient and transformer temperatures such that hot spot temperatures reached no more than 98°C. The project reporting documents numerous issues that were encountered with the intended RTTR methodology. No data analysis results are presented and it appears that the implementation difficulties have severely limited the ability of the project to draw any strong conclusions from these trials. The final implementation resorted to using additional sensors with the Remote Distribution Controllers (RDCs) deployed by the ANM system. This approach resulted in a RTTR calculation cycle of 30 minute periods. The project documents that this time scale is still within the transformer transient period and a cycle of 180 minutes would be required for reliable results. The project states that, "w*hilst there is uncertainty within the calculations, the data from the RDC showed that there is potential for additional capacity depending on the location of the transformer and the shape of the load curve. Within the time available it was difficult to draw useful learning from the data available"* [82]. Some additional modelling was undertaken; however, this was carried out using a hot spot limit of 130 degrees and hence could not be compared to static ratings at 98°C. Despite the major technical issues with data from the transformer trial, the project argued for a general potential for additional capacity depending on the location of the transformer and the shape of the load curve.

In addition to trialling RTTR methodology, the CLNR project considered the data gathered with respect to existing ER standards P15, P17 and P27 [83] and considered the option of bespoke thermal ratings instead of real time ratings.

From CLNR, NPG have taken forward the following policy regarding asset ratings [22].

- Where initial assessment indicates reducing thermal margins, roll out bespoke rating assessments for all assets and all customer groups.
- RTTR will be deployed in conjunction with power flow management schemes for DG customers facing a potential thermal constraint. This includes utilising flexible demand as well as generator curtailment.

Note: NPG expected take up of RTTR projects in 2015-2023 is single figures.

8.2.2.1 Key Learning

The key learning published in the reporting referenced in this section is set out below.

RTTR for EHV/HV/LV Cables:

- Increases to the current levels of circuit loading were shown to be possible.

- The value of ambient soil thermal resistivity greatly affects the cable rating - correction factors provided by ER P17 need to be applied where appropriate.
- For the both EHV and HV cables, the rating calculation results indicate that the headroom given in ER P17 will be reduced as the ground soil condition is worse than the conditions assumed.
- Results of the LV cable rating calculation indicate that the rating headroom of the LV cable will remain broadly the same as the rating using ER P17 estimated ground conditions.
- Replacing the cable thermal backfill with materials of lower soil thermal resistivity is proposed as a first step to increase the circuit capacity of underground cables.
- In general the project concludes that there is no practical benefit from real-time rating. Instead, offline bespoke analysis, based on detailed monitoring, is the most effective way to release latent capability within underground cables.

RTTR for EHV/HV OHL:

- For EHV sites, RTTR are greater than the static rating for 95-97% of observations.
- For HV sites, the worst site performance observed was RTTR greater than static rating for approximately 80% of observations.
- The HV rating reduction is attributed to shaded areas combined with high ambient temperatures.
- RTTR for EHV and HV OHL is a viable enabling technology to release capacity as part of a coordinated area control scheme.

Bespoke thermal ratings:

- Bespoke ratings calculated with site specific data can provide a more accurate static rating that will often release headroom, but may also identify cases where headroom should be reduced.
- A generalised insight from the project is that bespoke ratings can release 10%-15% headroom for OHL lines and transformers, but will most often reduce headroom by around 10% for underground cables.

8.2.2.2 BAU Assessment

<u>33kV OHL RTTR</u>

The CLNR trials provide evidence of significant potential benefit from 33kV OHL RTTR. The business case is not thoroughly discussed in the project reporting but is linked to the case for wider coordinated control. The project also highlighted issues around sheltering. The concept of enhanced static ratings based on bespoke analysis was identified as a possible alternative to RTTR. **BAU Score: 2.**

<u>11kV OHL RTTR</u>

The CLNR trials provide evidence of some potential benefit from 11kV OHL RTTR. The business case is not thoroughly discussed in the project reporting and sheltering issues were noted to be more significant at 11kV. The concept of enhanced static ratings was identified as a possible alternative to RTTR. **BAU Score: 1.**

<u>Transformer RTTR</u>

The CLNR trials represent early learning in the area of transformer RTTR, and further work is recommended by the project. **BAU Score: -1.**

<u>Underground Cable RTTR</u>

The CLNR trials conclude RTTR of underground cables is not an effective method of releasing capacity. Bespoke analysis for enhanced static ratings is deemed more appropriate. **BAU Score: -4**

8.2.3 WESTERN POWER DISTRIBUTION

An alternative approach to implementing real-time ratings (called Dynamic Line Rating (DLR) by the project) was one of the solutions trialled in the Low Carbon Hub project [70]. DLR was implemented for 33kV OHL aiming to increase DG hosting capacity. The solution had been developed and tested at 132kV in previous WPD IFI work. Instead of deploying weather stations to provide data for real time ratings, the approach utilised real-time measurements of wind farm electrical output to calculate wind speed. The wind speed is input to a DLR algorithm to calculate the real time rating.

The FALCON project undertook Dynamic Asset Rating (DAR) for three 11kV overhead lines, two primary transformers, 16 distribution transformers and two 33kV and one 11kV underground cable section. The project's definition and implementation of DAR is equivalent to what other projects call RTTR.

In the underground cable DAR trials the cables had a range of monitoring equipment installed that interfaced with an Alstom P342 relay which undertook a local, real-time thermal modelling assessment [84]. Key inputs were load current, soil temperature and soil moisture. The relay communicated via IEC 61850 over IP network to the NMS. The Alstom 'black-box' functionality was compared with off-line thermal models utilising the monitored data. In addition, cable (external sheath) temperature monitoring was deployed for validation of the thermal models. The FALCON methodology used the IEC 60853-1 standard as opposed to CRATER which is based on IEC 60853-2. The trial period was April 2014 to June 2015.

A trial of DAR for two primary transformers used a methodology based on the IEC 60076 calculation of hot-spot temperature [85]. The inputs to the model are load current and ambient air temperature. Various options were tested and compared for the thermal model with the final choice IEC 60076 version, tuned, showing good correlation to measured data. The dynamic ampacity of the transformer is estimated by incrementing the input load current to the model until a hot spot temperature limit is reached (98°C). This is then set as a continuous dynamic rating for that moment in time assuming an unvarying load. The trail period was April 2014 to May 2015. The project concludes that, "*dynamic asset rating associated with primary transformers* ***appear*** *to offer up to 10% average increase in rating at times of year when there is generally higher load, and as such* ***could offer potential*** *for further development"*[85] (page10).

The project reports additional challenges with respect to thermal modelling of distribution transformers due to a lack of available information beyond name plate rating plus significant variation in size, age, and cooling system design [86]. It was found that initial values of model parameters (largely taken from the available literature) provided insufficient correlation between modelled and measured top oil temperatures for all distribution transformers. Methods of parameter estimation using regression analysis were tested successfully, and satisfactorily accurate thermal models were developed on an individual basis for the distribution transformers included in the trial. The models are based on IEC 60076-7 standard. The dynamic ampacity of the transformer is as described for primary transformers above. The project concludes that t*he trial indicates that there is* ***potential benefit*** *from the deployment of Distribution transformer DAR, to reassess thermal capacity on a case by case basis* [86] (page 8).

FLACON also deployed Alstom P341 relays on three 11kV OHL feeders [87]. An offline model based on the CIGRÉ method was also developed for comparison against the relay calculated ampacity and the directly measured conductor temperature. The project concludes that, "w*hilst it has been demonstrated that ampacity of 11kV OHLs can be assessed, improvements in ampacity are essentially dependent on wind speed/direction, and cannot be relied upon if reasonable planning certainty of capacity is required. It is recommended that 11kV OHL DAR should not be considered a feasible technique for solving long term 11kV distribution network issues at this time"* [87] (page7).

8.2.3.1 Key Learning

The key learning published in the reporting referenced in this section is set out below.

33kV OHL dynamic rating:

- In general, the project concluded that for East Lincolnshire, the 33kV OHLs can typically be dynamically rated up to 113% of the static winter rating.
- However, Dynamic Line Rating was found to be less appropriate at 33kV than 132kV due to the increased risk of sheltering[27].
- The project CBA analysis indicates that the increased risk of sheltering at 33kV is too great and is not a viable option for further deployment.

11kV OHL dynamic rating:

- Good correlation was found between measured and calculated line temperatures.
- Significant variability in the calculated ampacity was observed in very short time frames due primarily to variation in wind speed.
- Results indicate significant average real time ampacity benefits; however, the rapid variation observed prohibits the asset being operated at the identified enhanced average levels.
- The 10 minute time constant of the line means that its variability and speed of change make it unsuitable for a dynamic rating where an element of forward prediction is required.

Underground Cable dynamic rating:

- DAR values were mostly below the P17 seasonally adjusted sustained rating during the summer months, and mostly above the P17 rating in the winter months. This outcome is attributed to the actual seasonal soil temperature varying significantly from the static value used within P17.
- Gains over P17 for the winter period (October to March inclusive), averaged 107% of the seasonally adjusted P17 rating.
- 24-48 hour ahead rating prediction was shown to correlate well with the measured rating.
- With tuning, it was noted that the thermal models appear to give good correlation to external cable temperature measurements. The results also correlate reasonably well with CRATER.
- The DAR of the Alstom relay was significantly lower than the offline thermal model in both winter and summer.
- In general the project concludes that this technique ***may*** be able to provide relief to cables hitting thermal limits in some circumstances. A further DAR investigation of a single cable is recommended.

Primary transformer dynamic rating:

- Significant variation in DAR values occurs around a seasonal trend attributed to transformer temperature being dependent on ambient air temperature.
- DAR values are mostly above the static rating; however, values less than this rating are observed in the summer
- Peak DAR value over the period is around 1.2pu and minimum DAR value over the period is around 0.9pu.
- Day ahead prediction of ampacity shows 95% accuracy to 0.04pu or less.

Secondary transformer dynamic rating:

[27] The effect of local geography sheltering segments of the line from wind and hence creating 'hot-spots' that are not accounted for in the RTTR methodology.

- The mean DAR values are above the static sustained rating up to six months of the year, typically in colder periods coinciding with the conventionally higher utilisation.
- Based on the outdoor distribution transformers, dynamic ratings are principally driven by ambient air temperature.
- The Trial results suggest that over winter there is scope to run the transformers with around a 10% increase in sustained rating with no increases in aging.
- There is more scope to dynamically rate outdoor transformers than indoor transformers.
- For day ahead rating prediction, the results indicate that around 5% error margin should be applied to the rating to allow 90% confidence that the predicted ampacity will be lower than that with measure real-time data.

8.2.3.2 BAU Assessment

<u>33kV OHL RTTR</u>

The Low Carbon Hub trials conclude that although an average uplift of considerable value can be achieved, the risk of sheltering is too great and the dynamic rating solution is not suitable for 33kV OHL. **BAU Score: -4.**

<u>11kV OHL RTTR</u>

The FALCON trials conclude that although some uplift benefits have been demonstrated, the uncertainty and variability at 11kV is too great and the solution should not be pursued. **BAU Score: -4.**

<u>Transformer and Cable RTTR</u>

The FALCON trials represent early learning in the areas of dynamic ratings for underground cables and transformers. There are indications of reasonable benefit; however, benefits and costs are highly uncertain and further work is recommended by the project. **BAU Score: 1.**

8.2.4 UK POWER NETWORKS

The UKPN Flexible Plug and Play project identified Dynamic Line Rating as offering significant potential benefit to enabling greater penetrations of wind DG in conjunction with ANM [88].

Four dynamic line rating systems were deployed across approximately 40km of 33kV overhead line within the Flexible Plug and Play trial area. The system deployed was the Alstom Micom P341 relay using metrological measurements from a Lufft WS501-UMB weather station. The DLR relay outputs were validated by a retrospective implementation of the CIGRÉ 207 model for comparison. A full year of data has been analysed to determine the performance of the DLR system.

8.2.4.1 Key Learning

The key learning published in the reporting referenced in this section is set out below.

- Ampacity was calculated to within approximately 2% of that determined using the relay, consistent for the whole period analysed.
- A significant number of excursions below the ER-P27 seasonal static ratings were observed, particularly in May and September. 1168 and 3505 minutes respectively representing 2.62% and 8.11% period of excursion versus the expectation from the standard as 0.001%.
- The trial adopted a worst case approach where the minimum calculated ampacity (from all weather stations deployed on the line) was adopted for the entire line. An average increase in ampacity of 14% was observed.

8.2.4.2 BAU Assessment

33kV OHL RTTR

The Flexible Plug and Play trials provide evidence of significant potential benefit for dynamic ratings for 33kV OHL. The methodology deployed appears to minimise the risks of sheltering to an acceptable level whilst still achieving a significant uplift. **BAU Score: 3.**

8.3 Discussion

The technologies deployed have been grouped into common technical categories and are discussed below. Although projects use a range of terminology to describe dynamic or real-time ratings, the term RTTR is used here. Table 40: RTTR Comparison in Appendix A – Summary Tables, provides an overview of the RTTR projects.

RTTR for 132kV Overhead Lines

SPEN were the only DNO to address this. The trial results indicated that a modest uplift in capacity can be achieved in a cost-effective manner.

RTTR for 33kV Overhead Lines

The Flexible Networks, CLNR, Low Carbon Hub and Flexible Plug and Play projects all undertook trials of this technology. The main application is to enable increased wind DG connection in conjunction with an ANM scheme. Results indicated average increases in ampacity upwards of 10%. Despite the average benefit, it was commonly found that there were frequent occasions that the RTTR was worse than the static rating, i.e. operating at the static rating would lead to thermal excursions with much greater probability than expected by the static rating standard. The issue of sheltering was deemed the major barrier to further deployment; however, some projects appear to have successfully implemented strategies that overcome this issue. One project indicates that bespoke static ratings should be a preferred first option. A diversity of trial results and hence opinion on future direction for this technology is apparent.

RTTR for 11kV Overhead Lines

The CLNR and FALCON projects undertook trials of this technology. Both projects indicate some potential average benefit in rating uplift; however, the extent and speed with which real time ratings varied (in response to wind speed) were deemed a major barrier.

RTTR of Underground Cables

The CLNR and FALCON projects undertook trials of this technology. Both projects provided insights into the challenges of developing thermal models for underground cables. Some limited average rating improvement was observed for winter months; however, it was noted that the real time ratings were actually below the static rating for significant periods of the summer months. Further investigation has been recommended by FALCON. CLNR has concluded that there is little practical benefit from a real time method and prefer a static rating solution based on bespoke analysis.

RTTR for Transformers

The Flexible Networks, CLNR and FALCON projects undertook trials of this technology. The focus was to improve understanding and implementation of thermal modelling (hot spot calculation) for transformers. Results indicated average increases in ampacity upwards of 10%; however, all projects indicate that further work is required in this area. One project indicates that bespoke static ratings are a preferable route forward.

8.4 BAU Overview

A summary of the BAU scores is provided in Figure 16. There appears to be a strong case for RTTR of overhead lines at 33kV and above. The contrary evidence from WPD's trials is based around the risks associated with sheltering. The evidence suggests RTTR at 11kV is more challenging and further work would be required to overcome the strong case against presented by WPD. For other types of asset RTTR there is only early learning and significant further work is required to provide strong evidence for or against BAU adoption.

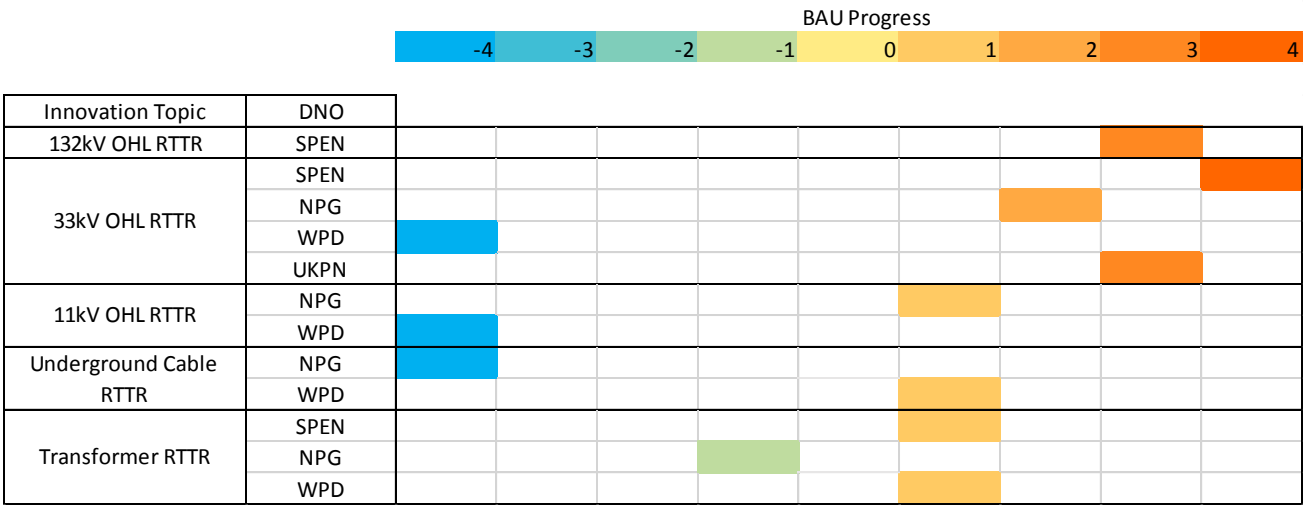


Figure 16: BAU Assessment for Real Time Thermal Rating Projects

8.5 Synthesis of Learning for Real Time Thermal Ratings

The synthesis of Learning and associated recommendations derived from the review in this section are set out below.

Learning:

- Results reveal that in general, static ratings are not always as conservative as had been commonly assumed and RTTR can be less than the static rating more often than expected by the existing standards.
- There are conflicting statements on the need for dynamic ratings; deployments of monitoring to calculate enhanced static ratings have been proposed as sufficient.
- RTTR for 132kV and 33kV overhead lines is well tested by LCNF projects.
- Average uplift for 33kV OHL is in the order of 10-15%.
- There are conflicting conclusions on the issue of sheltering for 33kV OHL RTTR.
- 33kV OHL RTTR or enhanced ratings can unlock capacity and should move to BAU, particularly with ANM for DG connections.
- RTTR for primary transformers was shown to enable 30% increase in peak loading above nameplate by modelling in one project; however, trials were limited to 10% by other asset capacity issues. Other projects had less conclusive results; however, in general, results suggest an uplift of 10% is achievable.
- RTTR for 11kV OHL, underground cables and distribution transformers requires further work – some benefits have been observed, but issues such as rapid variability and improved thermal modelling need to be addressed.

Recommendations:

- There is an opportunity for further knowledge sharing and collaboration to establish industry best practice on 33kV OHL RTTR.
- Learning and experiences from across the projects on RTTR for 11kV OHL, underground cables and transformers should be further reviewed and consolidated, with a view to establishing the most appropriate further innovation work for RTTR or bespoke enhanced ratings of these assets.

9 Synthesis of Learning on Obtaining and Utilising Network Data

The heat map analysis of LCNF project activity identified the synthesis themes:

- Enhanced Network Monitoring
- Enhanced Network Visualisation
- Enhanced Understanding of Existing Demand
- Enhanced Understanding of LCT

These themes are closely related and are therefore reviewed together under the heading of 'obtaining and utilising network data'. Although technically a type of distributed generation, PV is included here as a low carbon technology because the learning is primarily concerned with the monitoring of PV 'behind the meter' in order to develop improved understanding of the impact of PV generation on power flows in the Low Voltage network

The projects identified for review are shown in Table 21.

Title	DNO	Budget (£m)	Tier	Start Date	End Date
Distribution Network Visibility	UKPN	0.25	Tier1	Sep 10	Nov 13
Low Carbon London	UKPN	28	Tier2	Dec 10	Dec 14
Validation of Photovoltaic (PV) connection assessment tool	UKPN	0.38	Tier1	Jan 12	Nov 14
Demonstrating the benefits of monitoring LV network with embedded PV panels and EV charging point	SSEPD	0.32	Tier1	Sep 10	Sep 12
New Thames Valley Vision	SSEPD	22.8	Tier2	Dec 11	Mar 17
My Electric Avenue (Innovation Squared)	SSEPD	4.18	Tier2	Dec 12	Dec 15
Customer Led Network Revolution	NPG	31	Tier2	Dec 10	Dec 14
LV Network Templates	WPD	7.8	Tier2	Dec 10	Jul 14
Network Management on the Isles of Scilly	WPD	1.287	Tier1	Jan 11	Aug 13
PV Impact on Suburban Networks	WPD	0.1	Tier1	Feb 11	Nov 13
Hook Norton Low Carbon Community Smart Grid	WPD	0.34	Tier1	Feb 11	Oct 13
LV Current Sensor Technology Evaluation	WPD	0.25	Tier1	Dec 11	Jun 13
FALCON	WPD	12.4	Tier2	Dec 11	Sep 15
BRISTOL	WPD	2.2	Tier2	Dec 11	Jan 16
Implementation of an active fault level management scheme	WPD	0.646	Tier1	Feb 12	Dec 14
Ashton Hayes Smart Village	SPEN	0.2	Tier1	Jan 11	Oct 13
Flexible Networks for a Low Carbon Future	SPEN	3.6	Tier2	Dec 11	Sep 15
Low Voltage Network Solutions	ENWL	1.49	Tier1	Apr 11	Mar 14
ETA (Smart Street)	ENWL	8.44	Tier2	Dec 13	Dec 17

Table 21: LCNF Projects on Obtaining and Utilising Network Data

The review considered:

- What has been learnt on how to gather data from the network?
- What has been learnt on how to gather end use data and utilise smart meter data?

- What has been learnt from the data gathered (specifically for updated understanding of load characteristics and LCT impact)?
- What has been learnt on the use of electrical monitoring data from a network modelling and visualisation perspective?

All DNOs have been active in the area of network monitoring and most have several projects that include an element of deploying monitoring equipment and communication links. Relevant projects are listed in Table 34, Table 35 and Table 36 in Appendix A – Summary Tables. These tables provide short overviews of the monitoring equipment deployed and communications technologies trialled in the LCNF projects.

9.1 Project Details

9.1.1 UK POWER NETWORKS

The relevant UKPN projects are:

- Distribution Network Visibility (DNV)
- Low Carbon London (LCL)
- Validation of Photovoltaic (PV) connection assessment tool

The Tier 1 DNV project [89] aimed to fully utilise existing secondary substation RTU capabilities by upgrading RTU functionality, collecting increased volumes of data and developing visualisation and processing tools. Additionally, in areas not covered by legacy RTU, new monitoring equipment was tested. The DNV application has been adopted within BAU to support planning, connections and asset management. A positive CBA has been set out; however, this is enabled by the extensive existing monitoring assets.

LCL published a comprehensive suite of reports covering the wide range of activities undertaken by one of the largest LCNF projects [90]. Whilst not a 'visibility' project specifically, aspects relating to visibility were covered and are summarised here.

One component of the LCL project was to test the value of DNO access to smart meter data [91]. Operating in advance of the national smart meter roll-out, they worked in partnership with EDF by installing domestic meters that recorded half hourly kW consumption and additional meters for 10-minute average RMS voltage at remote ends of LV feeders. This was a work around to allow analysis of how the DNO might utilise smart meter data. The project collected data from ~5000 EDF smart meter customers. They grouped customers according to ACORN[28] categories and occupancy (number of bedrooms). Statistical analysis was undertaken to produce average demand profiles for the Elexon categories. Cumulative probability curves for maximum peak demand of any single customer were produced for each customer category.

Using a generalised diversity curve (Figure 17), and a table of peak demand values (Table 22) for the customer groups, a new After Diversity Maximum Demand (ADMD) design process was proposed that simply requires the identified customer's peak consumption to be summed and the appropriate diversity value to be applied.

[28] A geodemographic segmentation of the UK's population that segments households, postcodes and neighbourhoods into 6 categories, 18 groups and 62 types.

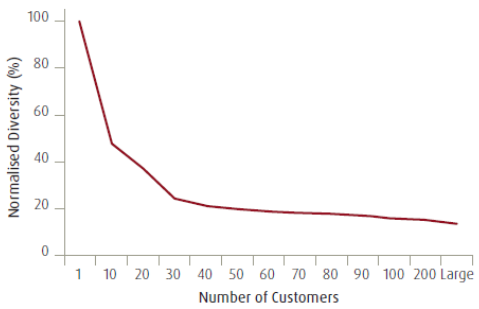


Figure 17: LCL General Diversity Curve, figure reproduced from [91]

		Bedrooms			
		1	2	3	4+
Acorn Group	Affluent	13	11	13	16
	Comfortable	11	11	12	14
	Adversity	9	11	12	14

Table 22: Scaled and rounded 75th percentile peak (kW) of households - reproduced from [91]

The charging behaviour of 54 residential EV customers was monitored for 302 days by the Low Carbon London project [92]. Diversity curves and charging profiles are shown in Figure 18

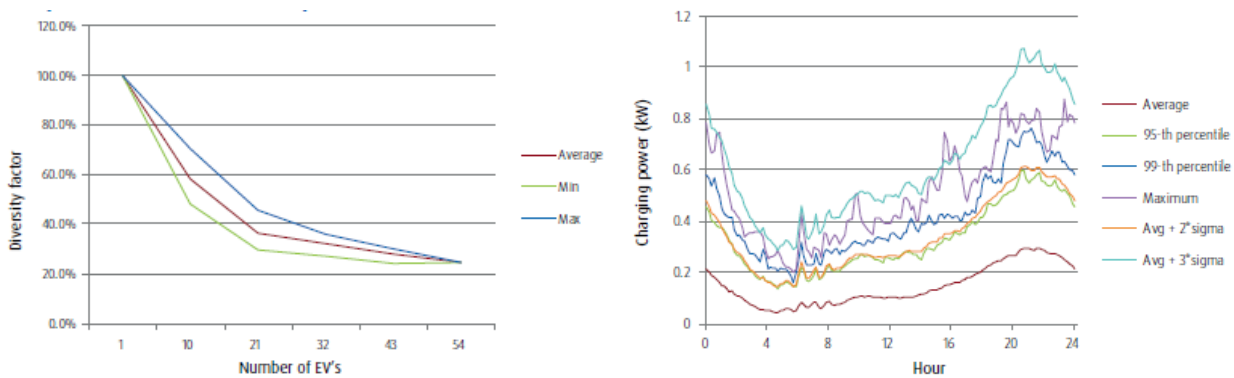


Figure 18: LCL EV Charging Profiles and Diversity Curves – reproduced from [92]

The heat pump trial [92] focused on 18 sites with heat pump monitoring equipment installed over the coldest period of the winter, between the end of January 2014 until the beginning of March 2014. The February data was extrapolated to form the profiles in Figure 19.

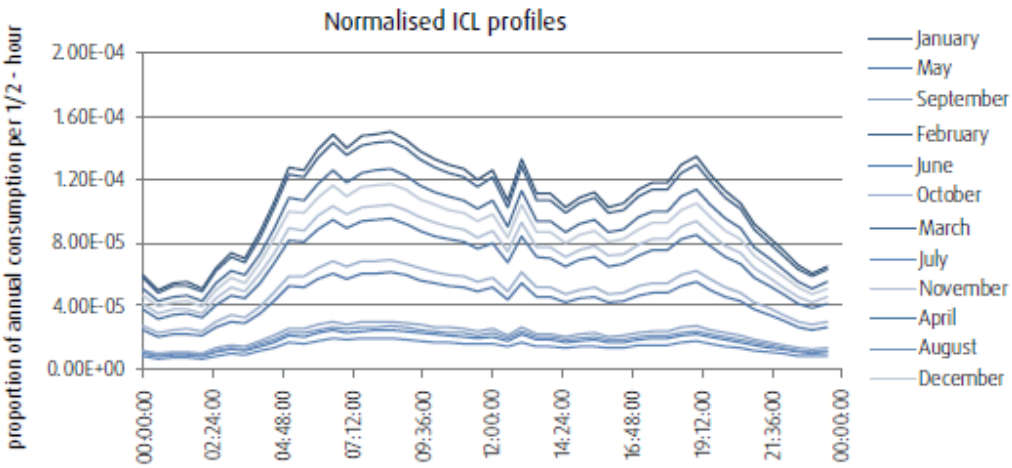


Figure 19: LCL Heat Pump Normalised Load Profiles – reproduced from [92]

Low Carbon London has collected and utilised extensive quantities of smart meter data. Analysing the data they produce new customer classification groups and probabilistic peak demand profiles. They have updated their understanding of After Diversity Maximum Demand. They have studied potential future scenarios and the use of smart meter data within them. Their analysis indicates little application of real-time monitoring and control; they see the main benefit in improved load profiling and forecasting. In their LCNF work they have examined in detail the potential applications of smart metering, but they have not developed the planning/forecasting tools/solutions their work has identified as required for realising full benefit of smart meter data.

LCL established three areas in London, designated Engineering Instrumentation Zones (EIZs). In the EIZs three 11kV feeders were instrumented, enabling a new application of distribution system state estimation (DSSE) to be tested and verified [93]. The DSSE trial was limited in that it assumed balanced steady state operation of the network and data availability and quality issues occurred. For example, V, P and Q measurements were unavailable at the supply points. However, in many of the top line trial results the project claims a promising degree of accuracy and the DSSE model was deemed to be robust and the trial a success.

The PV Connection Project deployed monitoring equipment to 20 distribution substations and 10 customers' PV installations in order to validate an Excel based tool for assessing PV voltage rise [94]. Learning on monitoring equipment and useful data sets have been produced and the tool has moved to BAU. The project established the following updated to design assumptions:

- PV generators do not increase the risk of unacceptable harmonic voltages or currents on LV feeders
- A substation busbar voltage of 248V.
- Minimum demand = 0W (<10 customers); 200W per customer (≥10 customers); up to 400W per customer (≥10 customers and high-energy-use demographic).
- Phase imbalance of existing single phase PV connections = 25% (urban); 50% (rural); all on same phase (< 10 customers).

Although still categorised as innovation by UKPN, enhanced distribution network visibility extending down to LV feeder level is prominent in the UKPN RIIO ED1 deliverables [95]. However, it appears that a tactical, needs driven approach will be taken on where to deploy visibility solutions as they are required to support smart grid solutions. *"The outcome of this has been that UK Power Networks does not at this stage see a defensible case for building significant investment into ICT for Smart Grids into our base business plan… our experience is that our innovation projects or trials once they move into a Business-as-Usual mode in small volumes are normally best accommodated with a tactical solution to their ICT requirements. Only once the Smart Grid solution is being used in large volumes does it become viable or necessary to put in place a more robust and enduring architecture*" [95] *(page 78)*

The DNV project states that, "*the overall costs per circuit mean that that application of HV circuit and transformer monitoring is likely to be gradual and based on specific network and load or generation growth needs rather than an extensive independent roll-out" [89].*

In their RIIO-ED1 Smart Meter Strategy [96], UKPN state with respect to Network Operations, Planning and the Path to the Smart Grid; "*there will be limited changes to the business model during ED1. We will focus during this period on accumulating smart data to drive our greater understanding of the network. Towards the end of mass rollout, we will acquire sophisticated modelling tools and establish a small team to assess and optimise the use of the data. Such tools and data are expected to significantly enhance the capabilities of the design and planning function and facilitate in a controlled manner (with regard to supply quality) the*

mass deployment of LCT and the move to smarter networks. This will predominantly impact ED2, but may generate some changes during ED1".

9.1.1.1 Key Learning

The key learning published in the reporting referenced in this section is set out below.

Learning on existing load:

- Up-to-date analysis of historic smart meter data can improve estimates of future customers' demand.
- Diversity of demand is consistent across customer types, so that a single diversity curve can be used to assess demand.
- Smart meter data can be integrated into current processes to improve service to customers and avoid unnecessary reinforcement costs.
- Functionality to analyse and visualise secondary substation load profiles has been developed. Half hourly profiles of secondary substations with RTUs for 2010 and 2011 were analysed to establish a library of load profiles.
- In general, substation load profiles followed expected seasonal and weekend/weekday patterns.
- Five kinds of existing load profile were identified:
    - Residential
    - Commercial
    - Mix of Residential and Commercial
    - Night
    - Industrial

Learning on LCT:

- Well educated and affluent people are more likely to be early adopters of EVs.
- The EV charging profiles derived by the project are similar to existing modelled profiles.
- EV load represents a significant addition (0.3kW[29]) to diversified residential peak load.
- The greatest impact of EV charging is at LV; however the expected reinforcement is only slightly greater than that forecast form background load growth.
- The heat pump load profiles provide a new understanding of heat pump load as having a flatter, less peaky profile.
- Heat pump impact is expected to be greater than EV charging.
- DNO visibility of EV and heat pump installation is essential.

Learning on PV:

- The areas monitored did not display any significant issue either at secondary substations or with respect to statutory voltages at end-points
- No hard and fast rules regarding diversity in panel output were established
- G83 records are not reliable

Learning on Network Monitoring and Visualisation:

- The DSSE, in combination with limited number of sensors and more extensive use of pseudo measurements, is a robust tool for improving the observability of distribution networks.

[29] EV peak averaged over approximately 50 households.

- The proposed and developed meter placement methodology in EIZs is robust and its applications have been demonstrated to significantly improve the network visibility.
- The uncertainty (error margin) of the estimated voltages is relatively small and in most of the cases, the error margin is less than 0.22% (in comparison to the error margin of individual meters: 0.3%-0.6%).
- The way in which the available network data is recorded and stored in the Distribution Network Operator's (DNO's) database can affect the effectiveness and accuracy of DSSE.
- The level of imbalance in distribution networks can be large, reducing the accuracy of the DSSE which assumes that the system is balanced.
- Further work will be required to quantify the economic benefits of the application of DSSE in distribution networks.
- The DNV application displays time series data collected from primary and secondary substation RTUs and associates it with data from other asset management and weather databases. It can present data in various formats such as trends, bar charts, table or geographically, as requested by the user.
- Two commercially available load flow tools (GE DPF and CGI DPlan) were trialled for 11kV network modelling. Challenges in providing sufficiently accurate asset information to the tools along with functionality limitations of the tools themselves prevented further development of load flow aspects of the project.

9.1.1.2 BAU Assessment

Enhanced Network Monitoring (11kV Feeders, Secondary Substations, LV Feeders)

UKPN currently have gained extensive experience with enhanced network monitoring, installing a range of monitoring solutions across their trial networks. Although the business case will depend on the specific application (need for visibility), deployment of network monitoring solutions should now be a BAU process and UKPN state that they expect to reactively deploy enhanced monitoring during ED1. **BAU Score: 4.**

Utilising Smart Meter Data

UKPN have gained extensive experience in gathering and using smart meter data to update understanding of load and produce new design values and profiles for residential loads that are suitable for immediate adoption into current planning tools. The benefits of accessing smart meter data to maintain understanding of residential load appears to be well established. Planned implementation by UKPN is not fully clear in the reporting. **BAU Score 3.**

Enhanced Network Visualisation

UKPN have developed and piloted capabilities for network visualisation in their LCNF projects. These include Distribution System State Estimation, lower voltage network modelling and a data analytics tool, linked to other asset management systems.

11kV modelling tools have been trailed, however significant challenges were encountered around accurate asset information and modelling capabilities. **BAU Score: -1.**

Although the DSSE trials demonstrated benefits, UKPN indicate there are still significant uncertainties and it will continue to be an innovation focus during ED1. **BAU Score: 1.**

The DNV tool is considered BAU by UKPN. **BAU Score 4**.

Enhanced Understanding of Load

New secondary substation load profiles have been established along with new residential ADMD design values and profiles. There appears to be no significant barriers to BAU adoption of this new knowledge. **BAU Score: 4.**

Enhanced Understanding of LCT

Improved understanding of domestic PV has been obtained and a new planning tool based on revised design rules has been developed. **BAU Score: 4.**

9.1.2 SCOTTISH AND SOUTHERN ENERGY POWER DISTRIBUTION

The Demonstrating the Benefits of Monitoring LV Networks project investigated and demonstrated appropriate substation monitoring that could be installed retrospectively to assess the network impacts of PV and EV uptake at a development of ten low carbon homes [97].

The NTVV project is gathering data from 250 smart meter deployments in Bracknell [98]. 10 LV domestic customer classes have been produced that characterise energy use behaviours [99]. The characterisation highlights significant variation in when peaks occur and the extent of those peaks (by time of day, day of week and week of season). Groupings are based on these metrics. Forecasting and Buddying are two key methods that are being tested for applications in planning. The anticipated benefit is reduced requirements for data from both network monitoring and from smart metering. The project is underway and full learning outcomes are yet to be published at the time of review. A Tier 1 pre-cursor to NTVV investigated the detailed electrical modelling of the LV network [100].

My Electric Avenue has deployed over 200 electric vehicles (Nissan Leaf Mark 2 - 3.5 kW charging with 24 kWh battery) for a period of 18 months to examine their impact on GB low voltage networks [45]. The project deployed a system (Esprit) which monitors LV networks and curtails EV charging to mitigate their impact. Statistical analysis of the EV charging data has been undertaken to establish new insight on EV charging impact and the benefit of managed charging [44]. Diversified EV charging demand has been analysed and is shown in Figure 20. The project utilised power line carrier (PLC) communication between distribution substations and electric vehicle chargers to limit electric vehicle (EV) charging when required by the LV distribution network [101]. Reliability was found to be an issue.

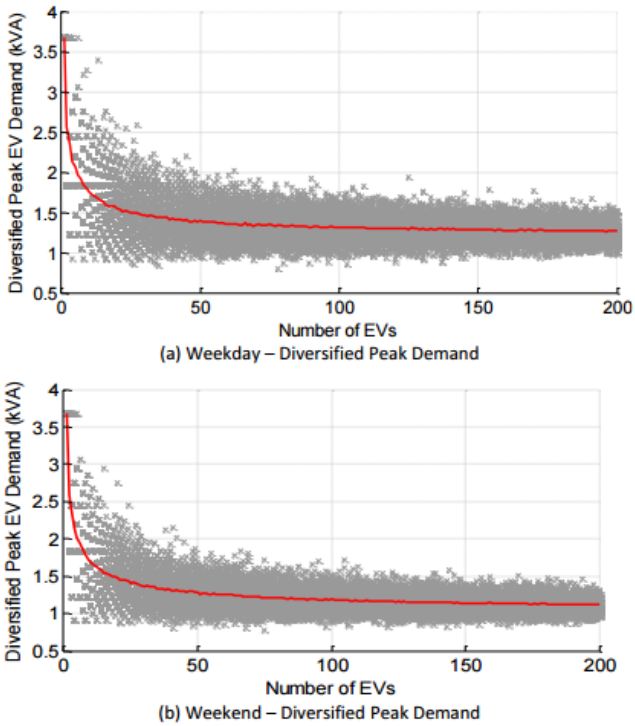


Figure 20: My Electric Avenue Diversified Demand for EV charging – reproduced from [44]

SSEPD have demonstrated managed EV charging via a novel commercial arrangement with a 3rd party. The technology supplier deem the trial a success and expect to further develop the solution. In terms of BAU for the DNO, the principle of contracting for managed EV charging has been well established and should be close to a BAU option. It should be expected to be considered against other potential solutions as EV clusters develop.

9.1.2.1 Key Learning

The key learning published in the reporting referenced in this section is set out below.

Learning on LV Network Monitoring:

- The project developed a work instruction by which monitoring equipment can be installed safely and efficiently without taking customers off supply.
- A G-clamp was selected for direct live connection onto low voltage busbars to obtain a voltage reference.
- The modes of operation to which a monitoring system would be expected to operate were established.
- Transmission of data by GPRS was demonstrated.

Learning on LV Network Modelling:

- From an evaluation of power system analysis tools, CYMDIST was deemed the most suitable for LV network modelling.
- Integration of data from SSEPD's GIS system and Smallworld Electric Office was successfully implemented.

Learning on PLC:

- PLC was found to be effective for 65% of all measurements across the project participants.
- There is an exponential correlation between distance and reduced reliability of communications for the participants where distance could be isolated. However, the certainty of this correlation is low due to the relatively low number of participants.
- The system implemented by My Electric Avenue allowed units to relay messages along the LV network. It was found that increasing the number of units relaying messages increased communication reliability and allowed communication with participants at distances of up to 300 meters.
- The presence of cable joints on the network was not commonly found to influence PLC communication reliability across the trials.
- PLC communication reliability was shown to improve with an increase in the number of viable signal paths. However, the results were not comprehensive for high numbers of signal paths due to the sparsity of the networks.
- There was a strong correlation between the PLC communication reliability and the load on the network. PLC communication reliability was found to reduce with increased network load.
- Interference caused by solar photo-voltaic (PV) generation was not generally found to reduce PLC communication reliabilities. However, for one participant there was indication of reduced communication capability when PV generation was occurring.
- There was no correlation observed between PLC communication reliability and EV charging.

Learning on LCT:

- The peak demand for residential EV charging has been found to coincide with the traditional residential evening peak

- Increased penetration of EVs can cause both thermal and voltage problems on LV feeders. Thermal problems typically occur ahead of voltage problems
- Modelling representative LV feeders has shown that 22% of LV feeders in one DNO license area will require intervention at EV penetrations of between 40% and 70%. This will occur across GB in 32% of LV feeders (312,000 circuits).
- PLC was found to be effective for 65% of all measurements across the project participants.
- There was a strong correlation between the PLC communication reliability and the load on the network. PLC communication reliability was found to reduce with increased network load.

Learning on PV:

- Busbar voltages were seen to exceed the specified voltage limits that would apply at the point of connection
- Real and reactive power flows were measured on the circuit to which PV is connected, and the harmonic content of the same feeder was observed to be low.
- At this level of PV connection to a low voltage feeder (10 houses) in an urban environment, no net detrimental impact on the LV network was observed.

NTVV is building the solutions to allow detailed LV modelling, visualisation and planning using smart meter data and secondary SCADA. Early learning has been disseminated; however, trials are still underway so no final reporting on learning is available yet.

9.1.2.2 BAU Assessment

Enhanced Network Monitoring (Secondary Substations, LV Feeders)

Enhanced Network Monitoring solutions have been developed to a good degree by SSEPD. Although the business case will depend on the specific application (need for visibility), deployment of network monitoring solutions should now be a BAU process. **BAU Score: 4.**

Utilising Smart Meter Data and Enhanced Understanding of Demand

NTVV has produced some initial insights on residential demand and is developing a highly novel approach for utilising smart meter data. However, the evidence of NTVV needs to be assessed on project close and at present is inconclusive. A BAU score is therefore not appropriate at this stage.

Enhanced Network Visualisation

An NTVV pre-curser project tested LV modelling environments. The technical concept of integrating existing data sources and implementing detailed LV modelling was proven; however understanding of the benefits and hence the business case depend on work currently underway within NTVV, hence significant uncertainty exists on the case for BAU. **BAU Score: 1.**

Enhanced Understanding of LCT

My Electric Avenue has provided new insights on EV charging behaviour and impact analysis. This learning will become increasingly relevant for application in planning processes as LCT penetrations grow. **BAU Score: 2.**

9.1.3 NORTHERN POWERGRID

In CLNR, the data from ~9000 domestic smart meter customers was collected for the years 2011 (May 2011-April 2012) and 2012 (May 2012-April 2013) [102]. Statistical analysis grouped customers according to the MOSAIC[30] categories and also in terms of project-defined socio-economic categories. Statistical analysis was

[30] http://www.experian.co.uk/marketing-services/products/mosaic-uk.html

undertaken to produce profiles in a similar format to the ACE49 and Elexon[31] profiles currently used in DEBUT[32] style planning tools [103]. New design values for use within current ADMD methods were also produced [104].

Figure 22 provides an example of the profiles generated by CLNR. In Figure 21 the mean profiles are normalised by annual energy consumption, demonstrating that the main differentiating factor between customer types is determined by this factor.

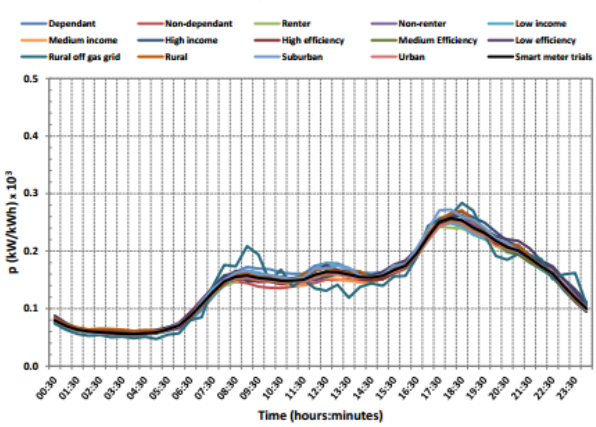


Figure 21: Mean Demand Factor 'p' Profiles for CLNR Customer Groups – reproduced from [103]

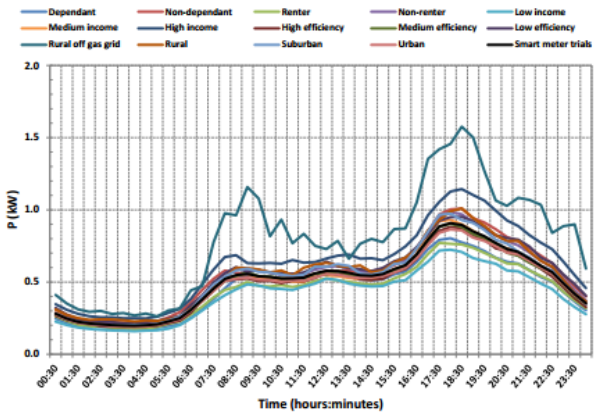


Figure 22: Mean Demand 'P' Profiles for CLNR Customer Groups – reproduced from [103]

The process to determine the new ADMD design values was: sample a set of *I* customers and find the maximum mean demand for that set. This process is repeated 1000 times. The ADMD results for *I* = 100 customers are summarised in Table 23 and the CLNR ADMD curve is shown in Figure 23.

Category	ADMD Values
All Customers	1.57kW
MOSAIC Groups	1.05kW to 2.62kW
CLNR Groups	1.21kW to 1.62kW

Table 23: Summary of CLNR ADMD Values – reproduced from [104]

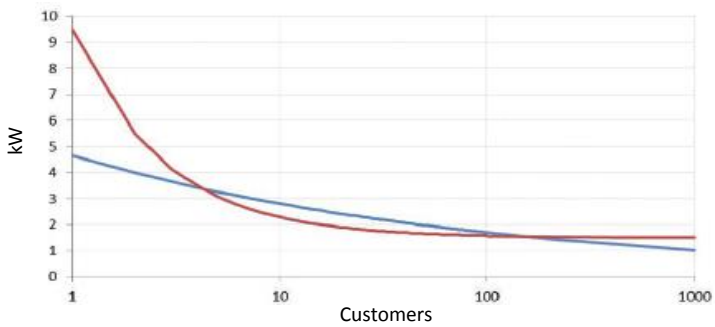


Figure 23: CLNR Generalised ADMD curve – reproduced from [104]

Monitoring was deployed to understand the impact of LCTs on network feeders at LV and HV and the behaviour and impact of the smart solutions. Data collection and analysis was undertaken for a group of ~133 EV customers [105]. Figure 24 demonstrates the CLNR EV average demand profile.

[31] https://www.elexon.co.uk/reference/technical-operations/profiling/
[32] http://www.eatechnology.com/products-and-services/create-smarter-grids/windebut

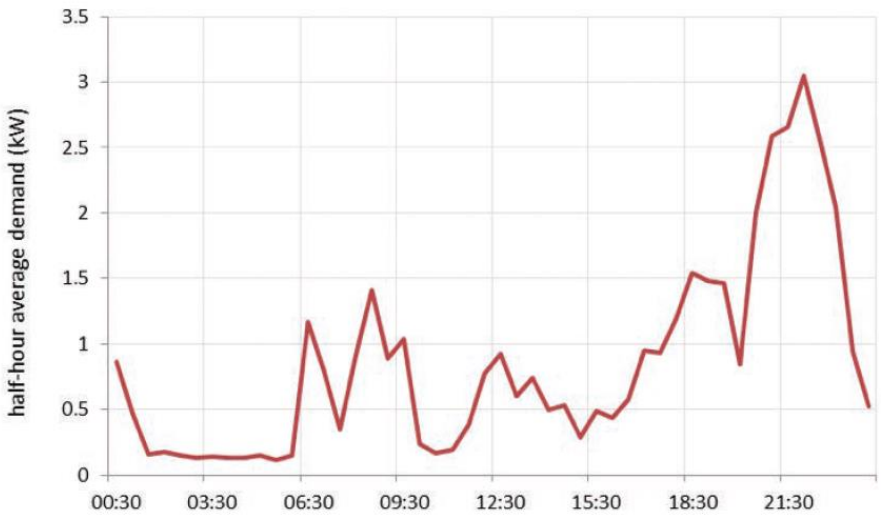


Figure 24: CLNR Average EV Demand Profile – reproduced from [105]

Statistical analysis was undertaken for approximately 90 households with air source heat pumps for 1 year 1st April 2013 – 31st March 2014 [106]. Following the CLNR process, average demand profiles and a new ADMD demand curve were produced. Figure 25 shows the average demand disaggregated by Heat Pump and Household components.

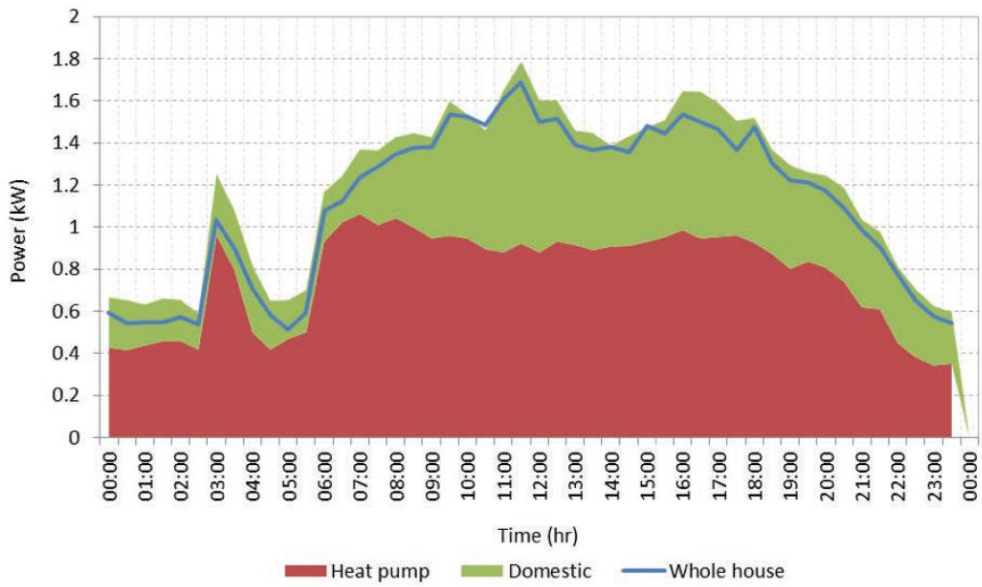


Figure 25: CLNR Heat Pump Average Demand Profile – reproduced from [106]

Data for ~140 Solar PV customers was collected for the calendar year 2013 [107]. Analysis of declared capacity versus actual output revealed an element of diversity with aggregate generation trending to 90% of capacity (Figure 26).

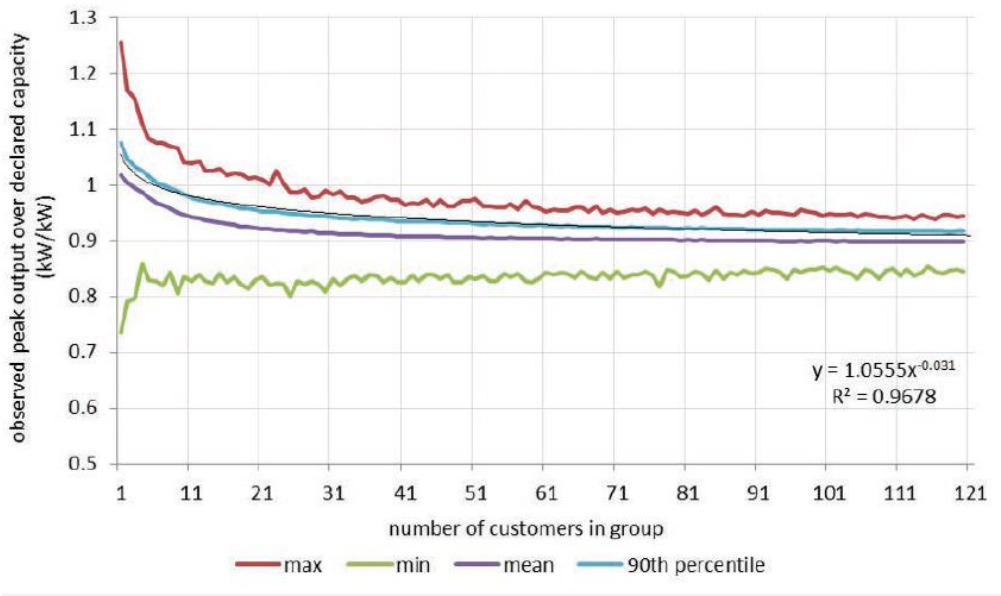


Figure 26: CLNR Solar PV Observed Output Vs Declared Capacity - reproduced from [107]

Average half hourly design demand profiles were established (Figure 27) and used to model voltage headroom on CLNR test networks (Figure 28).

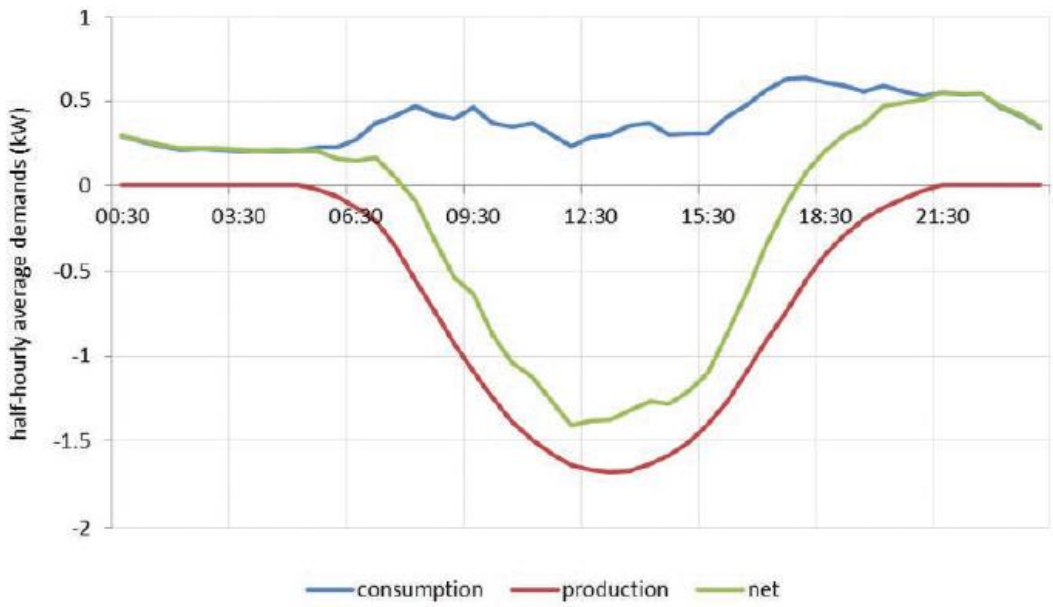


Figure 27: CLNR Solar PV Average Demand Profile - reproduced from [107]

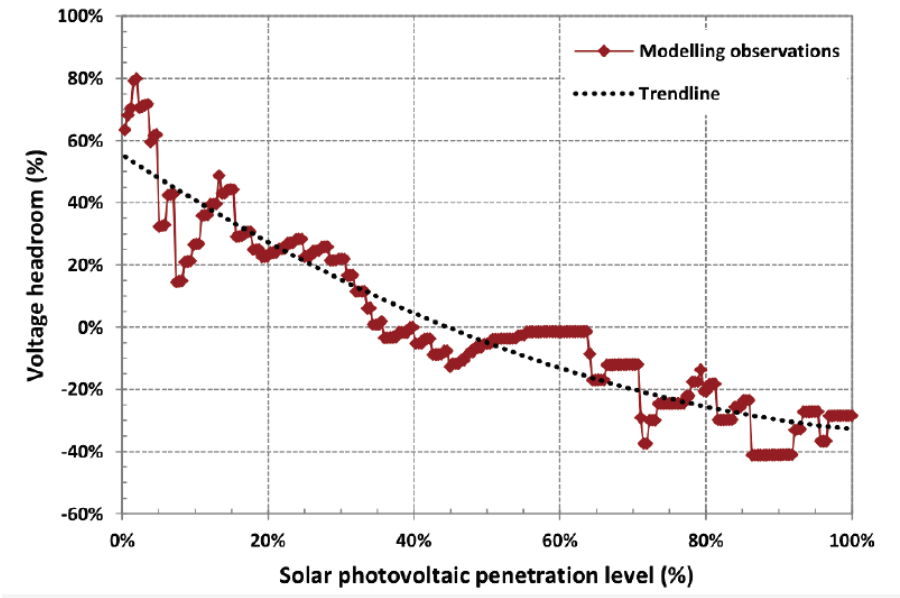


Figure 28: CLNR Solar PV Voltage Headroom Analysis - reproduced from [107]

An extensive suite of monitoring equipment was deployed by CLNR [108]. The equipment deployed is summarised in Table 36 in Section 14.1.3 and displayed in Figure 29.

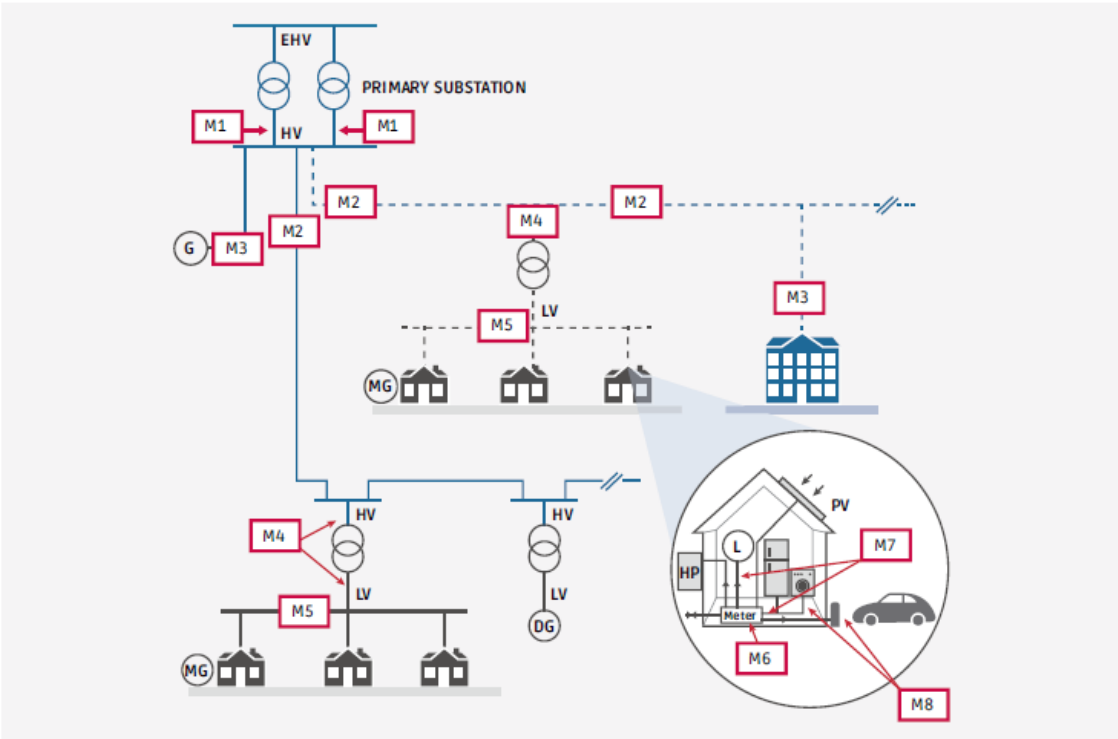


Figure 29: CLNR Monitoring Deployment –reproduced from [108]

The project learning produced the following recommendations for HV & LV Planning Purposes:

- A minimum of half-hourly averages of real and reactive power per phase at primary substation transformers and feeders.

- Half-hourly average voltage of lower voltage busbars at primary and secondary substations.
- Half-hourly average real power of each phase of each feeder at secondary substations.

In addition, for HV & LV design purposes:

- 10 minute averages of real and reactive power of each phase of feeders of interest at secondary substations.
- 10 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.

For real-time active management at HV & LV the following recommendations were made:

- For primary sites (6.6kV, 11kV or 20kV), voltage (V > 100V) step change updated in less than 15 seconds.
- For secondary sites, 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

The CLNR project deployed an area control system called the Grand Unified Scheme [68]. The control system was supplied by Siemens and is based on their Power 5 (formerly Power CC) platform. The system includes DSSE and also requires extensive monitoring of substations and feeders from Primary to LV. Modelling the HV and LV networks in sufficient detail was reported as a major challenge. Existing electrical and connectivity data had to be converted into a suitable format for modelling in IPSA. The Denwick test cell model (two HV feeders and half a dozen LV networks), when simplified, had in excess of 2000 bus bars. It was highlighted by the project that the maintenance required to keep the model up to date was substantial.

A prototype Network Planning and Design Decision Support (NPADDS) software tool was developed by CLNR. It was a proof of concept project for network headroom assessment and representation of LCT and CLNR technologies [109]. Rather than developing new network modelling functionality NPADDS interfaces with existing NPG planning tools including: DEBUT, EGD, IPSA2, Crater Lite and Transformer Thermal Modelling Tools. The new planning profiles produced by CLNR are used for planning analysis and where network constraints are identified, NPADDS provides 'Solution Templates' to assess possible interventions.

NPG states an intention to (driven by LCT deployment) to extend secondary SCADA and LV feeder visibility. This data is intended to feed a State Estimation system. ED1 submissions regarding smart meters[33] refer to developing "a *data warehouse to pre-process and store smart meter data for design and planning"*. Furthermore they "*will develop our planning processes during ED1 to ensure we capture the smart meter benefits before ED2.*

9.1.3.1 Key Learning

The key learning published in the reporting referenced in this section is set out below.

Learning on load:

[33] http://www.yourpowergridplan.com/som_download.cfm?t=media:documentmedia&i=1738&p=file

- Regular domestic customers contribute about 40% less to system peak demand than previously assumed, down from 1.5kW to 0.9kW.
- The project analysis found this to be a combination of customers using less energy overall through the year, and also drawing power more evenly across the day and year.

Learning on LCT:

- Results appear to indicate very little diversity in EV charging. The project finds an ADMD for 100 customers = 3.6kW which is approximately the charger rating per household. When the whole household load is considered, ADMD =3.8kW.
- The project close down reports indicate that the ADMD calculations for EV are inconclusive.
- An average heat pump load profile has been derived from approximately 90 households. The profile is relatively flat during the day where most of the load occurs, but contains a sharp peak overnight that matches the day time peak.
- Heat pump ADMD peak load is 1.2kW for 100 houses.

Learning on PV:

- 90% of rated capacity is a reasonable planning value for aggregated domestic PV.
- Findings indicate penetrations upwards of 30% Solar PV can result in voltage issues.

Learning on network visualisation:

- State estimation has been demonstrated on four network areas to be a sufficiently accurate method of estimating voltages and power flows with limited monitoring data.
- The configuration and maintenance of a state estimator is a non-trivial task
- Issues were encountered regarding the state estimator being robust to connectivity changes.
- Integration of data from multiple existing databases has been demonstrated in a tool for headroom capacity assessment of lower voltage networks.

9.1.3.2 BAU Assessment

<u>Enhanced Network Monitoring (11kV Feeders, Secondary Substations, LV Feeders)</u>

The CLNR project has demonstrated deployment of extensive instrumentation to undertake enhanced network monitoring. Secondary substation monitoring solutions are well developed and committed to during ED1 in a reactive strategy. Although the business case will depend on the specific application (need for visibility), deployment of network monitoring solutions should now be a BAU process. **BAU Score: 4.**

<u>Distribution System State Estimation</u>

CLNR developed a DSSE and area control architecture with network visualisation functionality. These solutions are still at effectively at pilot stage and NPG do not anticipate using this solution in ED1. The business case for DSSE as an enabler for coordinated area control is highly uncertain. Further development is possible with a view to ED2. **BAU Score 1.**

<u>11kV and LV Network Modelling Tools</u>

The NPADDS tool does not include new network modelling functionality, but it demonstrates a level of data integration that enhances modelling capabilities for lower voltage networks and allows 'smart' solutions to be considered. As a proof of concept project, there is little analysis of the business case for BAU deployment. It appears this tool will be developed further within ED1 innovation projects. **BAU Score 2.**

Utilising Smart Meter Data and Enhanced Understanding of Demand

The CLNR project has utilised smart meter data to establish new customer load profiles in industry standard format ready to be applied within existing planning tools. These outputs, and the process to maintain understanding of demand via smart meter data, should be adopted as BAU immediately. **BAU Score: 4**

Enhanced Understanding of LCT

New insights have been obtained on EV and HP load profiles, and PV generation profiles. This knowledge has been incorporated into a new prototype planning tool that appears ready for BAU; however, this is not expected to be required in the near future (in the absence of significant LCT penetration). **BAU Score: 2.**

9.1.4 WESTERN POWER DISTRIBUTION

WPD undertook a selection of Tier 1 projects trialling monitoring of secondary substations. These projects map a learning journey culminating in the LV Current Sensor Technology Evaluation project. An evolution in improved market offerings, particularly in retro-fitting LV current sensors with minimal/zero interruptions, is also apparent. Learning from these early projects and the improvements in market offerings are likely to have fed into monitoring deployments in later, larger projects from several DNOs.

The Network Management on the Isles of Scilly project aimed to establish a real-time monitoring system on all the distribution substations of the network area [110]. Broadband over Power Line (BPL) and radio communications were both tested.

In the Hook Norton Low Carbon Community Smart Grid project, substation monitoring was installed in 11 substations with 46 load monitoring nodes installed in customer premises [111]. Radio communications were established between the substations and the WPD communications network. Data was exported from the WPD NMS to the National Energy Foundation every 15 minutes where it was in turn published on a customer portal. Power line carrier communications have been successfully used between customer nodes and distribution substations.

Early LV monitoring projects suffered from a lack of market solutions that avoided the need for customer interruptions. In response to this issue being highlighted by the LV Templates project [112], Ofgem raised concerns and required a consultation. Following this, the LV Current Sensor Technology Evaluation project [113] was developed to conduct a detailed assessment of the market as it stood and to inform the wider DNO community of its findings. The project conducted a comprehensive evaluation of seven commercially available LV monitoring solutions (Figure 30) and the development of installation policies to allow wider scale deployment on the LV network. The overall conclusion of the project was that the current generation of monitoring solutions are mature enough to allow sufficient data to be collected by DNOs to assess the performance of LV networks. Monitoring solutions can provide network load measurement with accuracies to within 2.5% for Rogowski coils, and 1% or better for solid state sensors, such as split core CTs.

Manufacturer	Overall Rating	NPL Test	Ease of Installation	Installation time per site (Mins)	Relative Cost	Positive	Negative	Monitoring type
GMC i-Prosys	Excellent	Average	Easy	35-45	£	Plug and Play	Bulky metrology unit	Advanced
Sentec/Selex (Gridkey)	Excellent	Good	Easy	40-50	£	Plug and Play	Hard to access internal electronics	Advanced
Current	Good	Good	Easy	45-60	£££	Plug and Play	Case not fully weather proof	Advanced
PowerSense	Good	Average	Medium	60-90	££	Back up battery, robust case	Time consuming sensor connection	Advanced
Ambient	Good	Good	Easy	45-60	£££	Plug and Play	No commissioning indicators. One unit per feeder	Advanced
Haysys	Satisfactory	Average	Hard	90-100	£	Large sensor aperture	Time consuming sensor connection	Basic
Locamation	Satisfactory	Good	Easy	45-60	££	Plug and Play	Electronics prone to failure	Advanced

Figure 30: LV Current Sensor Technology Evaluation of Seven Manufacturer Solutions – reproduced from [113]

In the PV Impact on suburban networks project, WPD installed substation monitoring on seven LV feeders and one substation transformer in order to assess voltage and current ranges, harmonics, power factor and power flows [114]. As a result of this project, WPD amended existing design policies to allow the connection of a further 20% of solar PV on multiple LV properties.

The LV Network Templates project deployed a large-scale LV monitoring campaign of 824 substations including feeder end voltages [112]. Statistical analysis of the data monitored was undertaken to update current understanding of substation load profiles. The main project output were the LV Templates and the open source tool for their application. By inputting substation-specific data regarding customer numbers (by Elexon profile class) and equipment details, the LV Templates tool then produces seasonal, daily load and voltage profiles for use in planning (Figure 31). These are stated to be 80-90% accurate and representative of 50% of the GB network.

The LV network templates project also monitored 120 PV installations and augmented this data with a database of a further 500 customers. Their analysis supported previous work that found a diversified peak output of 80% nameplate capacity for PV connected to a secondary substation was a reasonable planning approach.

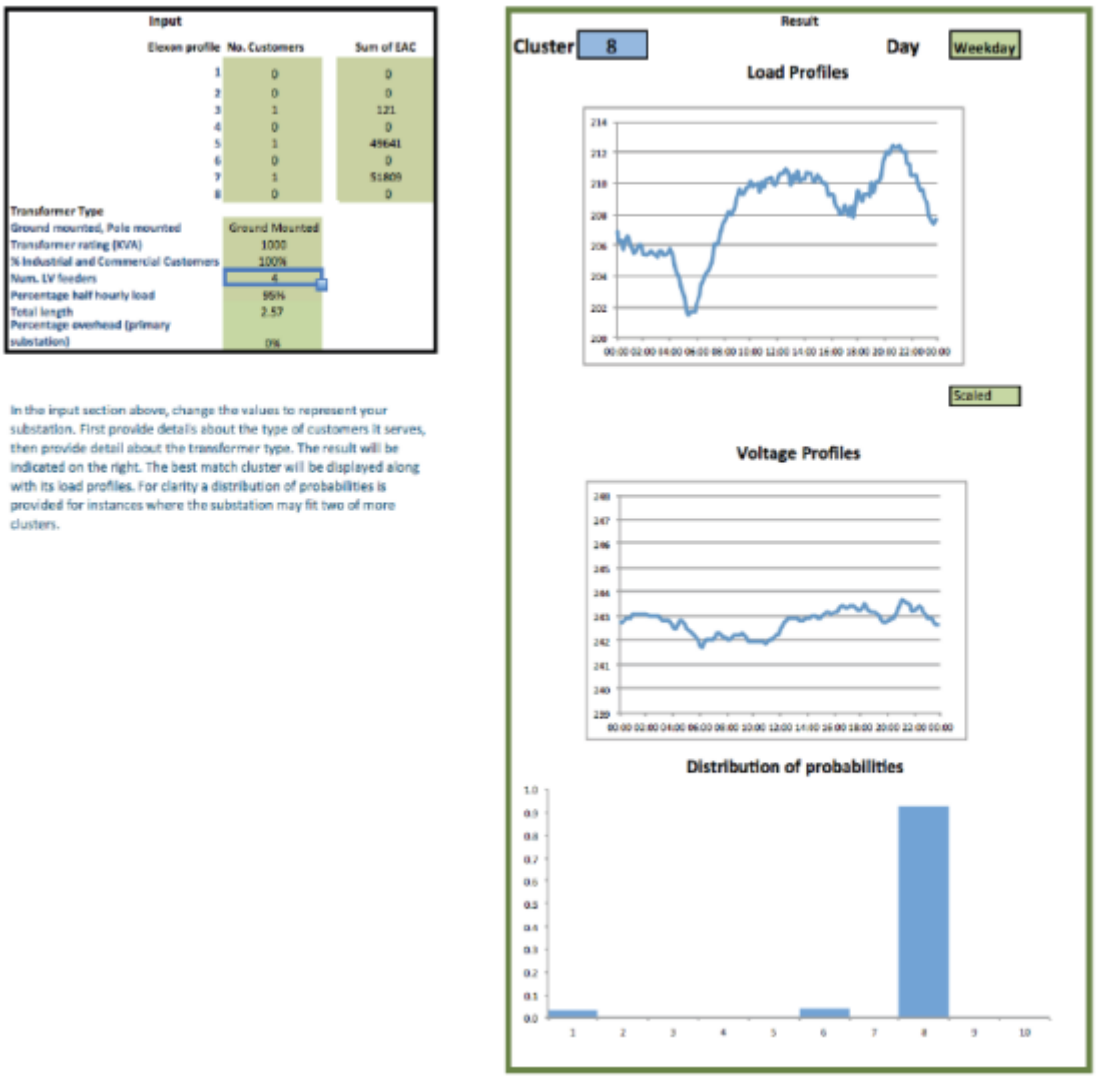


Figure 31: LV Network Templates Example Output – reproduced from [112]

The Implementation of an Active Fault Level Management Scheme project [115] deployed an Active Fault Level Monitor (AFLM) that consisted of an auto-closer device and a power quality monitor that enables real-time monitoring of fault level. The project provided proof of concept that the fault levels can be monitored remotely in real-time, opening the application for active management of DG connections.

The SoLa BRISTOL[34] project involves monitoring of 11 substations with connected BRISTOL customers undertaking trials of in-home DC energy management [40]. Potential project learning is primarily on the impact of the energy management systems on LV network loading. Trial numbers do not allow any significant impact to be demonstrated at present; however, some theoretical extrapolation indicates the EMS battery charging could have some network value. The project has yet to close at the time of this review and full review of learning outcomes has not been possible.

The FALCON project [58] included a significant monitoring and communications network deployment covering 158 distribution substations. The communications solution involved extensive WiMAX implementation [116]. Monitored data was used to develop an Energy Model that estimates distribution substation loading with verification comparing estimated loading versus measured values [117]. Future

[34] Buildings, Renewables and Integrated Storage, with Tariffs to Overcome network Limitations project

work requirements have been identified in order for this energy model to be used formally for 11kV planning and underlying data requirements for customer categorisation seems to be the most significant barrier. While the energy model has an overall tendency to overestimate load (Figure 32), the degree of overestimation is small for winter weekdays. As winter peaks are still the most onerous conditions for the majority of the network, this is unlikely to result in "false positives" within FALCON's Scenario Investment Model (SIM) suggesting unnecessary intervention.

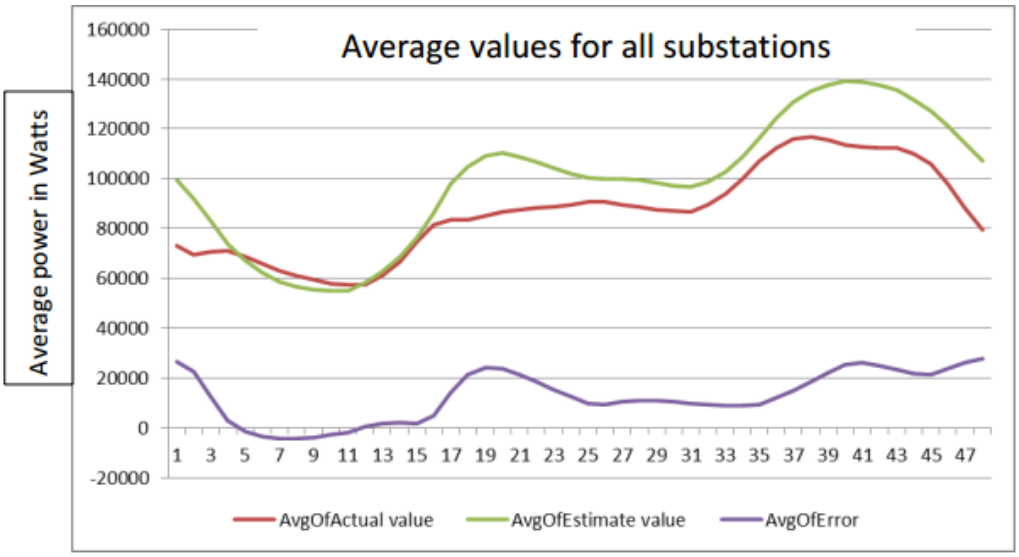


Figure 32: FALCON Energy Model Profiles compared with Measured Profiles – reproduced from [117]

WPD's projects have undertaken an expansive campaign of secondary substation monitoring and data analysis. They have generated extensive learning on secondary substation monitoring solutions that have benefited following projects. The prevailing theme of their approach is to use the data gathered to develop accurate load estimation tools that remove the need for secondary substation and LV feeder monitoring. Deployment of enhanced network monitoring should be well established as a Business As Usual process for WPD; however, the indications are that they will primarily utilise new understanding gained from their monitoring campaign rather than deploy additional monitoring. WPD indicate in the LV Templates reporting that their strategy is to apply LV Templates where it is deemed necessary to revisit traditional design assumptions. Where uncertainty exists in the application of templates, monitoring will be deployed. However, it appears that the Energy Model from the FALCON project has superseded the LV Templates approach.

WPD LCNF projects have not addressed smart metering. With reference to Smart Meters WPD state: We will make use of smart meter data from all of our customers to build a detailed understanding of the LV network. The smart meter data will complement the data from the LV Templates project and provide a check that the templates correctly reflect network usage.

9.1.4.1 Key Learning

The key learning published in the reporting referenced in this section is set out below.

Learning on communications:

- BPL solutions required HV outage for installation.
- Availability of radio was been good for the Isles of Scilly but the SD4 radios using allocated power industry spectrum have limited data throughput capabilities.
- For some links the performance of BPL falls below required standards for some time periods.

- Additional research is needed to understand the impact of load types on BPL performance, and in particular the impact on BPL from the connection of low carbon technologies
- PLC communication can work on UK LV networks with an average success rate of 70-75% with apparent links to network loading.
- Trails of radio backhaul communications solutions had a reliability in excess of 95%.
- WiMAX has proved to be a suitable radio technology for distribution network monitoring - yielding a low overall installation and operational cost solution while giving high levels of control to the DNO when compared to other candidate solutions such as fixed line.
- WiMAX radio offers a resilient IP network solution for use where site access and installation may be an issue.
- A low latency solution may be implemented by minimising the number of routing node hops necessary to communicate with terminating equipment, allowing a tele-protection scheme between secondary substations to be run over the WiMAX network.
- The use of half duplex communications on the radio links is not inconsistent with the typical network traffic, consisting of mainly small SCADA data packets.
- Workarounds for line of sight issues have been found.
- WiMAX radio lends itself to adaptation and adjustment in the field should expected theoretical signal coverage not be realised.
- The cost of the rugged WiMAX radio based solution for Project FALCON is modest when compared to the likely costs for an IP network infrastructure based on fixed line telecommunications. However, the potential licence costs associated with extending the use of the WiMAX solution from test to full operations is not factored into this assessment as it is currently unknown.
- It would be advantageous to utilities and other critical national infrastructure organisations to have access to a WiMAX / 1.4GHz frequency solution.

Learning on load:

- For most substations the FALCON Energy Model estimates are reported to be a good representation of the actual monitored results.
- The quality metrics for the Energy Model are better than those for the estimates created using the LV Network Templates tool.
- The substation characteristics linked to good or bad quality estimates are consistent with the findings of previous analysis for LV Network Templates and for earlier analysis within FALCON using estimates created by replicating the settlement process.
- Good quality estimates are more likely for substations serving a larger number of customers and where these customers are domestic, particularly those in Profile Class one.
- Substations serving a smaller number of customers are less likely to give good quality estimates as are those with a larger proportion of non-domestic customers (though this relationship is weaker).

Learning on PV:

- A diversified peak output of 80% nameplate capacity for PV connected to a secondary substation was found to be a reasonable planning approach.
- Solar PV had a relatively modest effect at reducing the traditional network peak demands in the morning (7:00am – 8:30 am) and during the evening (6pm – 8pm).
- Reverse power flow was not observed in the smaller trial.
- The voltage profile was found to be mainly dominated by the tap changers on primary transformers and not by voltage rise from embedded solar PV.

9.1.4.2 BAU Assessment

Enhanced Network Monitoring (11kV Feeders, Secondary Substations, LV Feeders)

Through the deployment of enhanced network monitoring in numerous projects, monitoring solutions are well tested by WPD and are to be reactively deployed in ED1. Although the business case will depend on the specific application (need for visibility), deployment of network monitoring solutions should now be a BAU process. **BAU Score: 4.**

Enhanced Understanding of Demand

The templates project created a new planning tool that generates secondary substation load profiles ready to be applied within existing planning processes. WPD indicate these will be used as BAU but have since also developed an alternative tool that is deemed superior. **BAU Score: 2**.

Enhanced Understanding of LCT

Extensive learning has been obtained regarding solar PV and incorporated into BAU design rules. **BAU Score: 4.**

9.1.5 SCOTTISH POWER ENERGY NETWORKS

The Ashton Hayes Smart Village project implemented monitoring solutions for supporting community smart grid aspirations [118]. The monitoring covered 4 distribution substations supplying the village of Ashton Hayes. Whilst too small a project to provide robust evidence, the project provided experience of community engagement and lent insight into LV operating conditions, hence indicating further work on new planning approaches, real-time rating and flexible demand were merited. The understanding gained on LV monitoring fed into the Tier 2 Flexible Networks project.

The Flexible Networks project [73] sought to analyse and implement alternative flexible solutions to network reinforcement with trials on three areas of network with known capacity issues. The project deployed new primary and secondary substation data monitoring to support these network innovations and further understand the value of monitoring. The monitoring deployment covered 8 primary substations and 184 secondary substations.

A large amount of learning regarding analysis of load and application into 11kV planning has been published [119]. Key outcomes included an improved statistical understanding of primary substation load forecasting and a proposed probabilistic approach to P2/6 that releases additional capacity headroom. Flexible Networks have published a Network Monitoring Good Practice Guide [120] and a future network monitoring strategy [121].

An example of the additional capacity that can be obtained from the proposed probabilistic approach is given in Figure 33 below.

Primary Network Groups	Ruabon	Whitchurch	St Andrews
Firm Capacity MVA	10	20	21
Half-hour Maximum Demand MVA	7.12	14.21	19.84
Minimum of 4 Highest Half-hour Loads MVA	7.02	13.94	19.33
% Additional Capacity Headroom	1.1%	1.3%	2.4%

Figure 33: Flexible Networks Headroom Capacity Improvements from Improved Load Characterisation –reproduced from [119]

Recommendations from the Future Network Monitoring Strategy [121]:

- Install "smart" MDIs instead of conventional MDIs in new secondary substations and replacement LV switchboards.
- Install "smart" MDIs in secondary substations at key locations across the LV network identified through application of the LCT Network Monitoring Strategy.
- Install secondary substation monitors with more detailed functionality at a small volume of selected locations of high LCT clustering and network constraints.

The project also developed a prototype Distribution Grid Analytics tool that utilised GIS data, NMS network configuration data, co-ordinates of monitoring locations and monitoring data [122]. A major issue was encountered in extracting data from existing systems. The project states *this was our first trial of data analytics. We believe that this technique is at least 2 years away from business as usual adoption* [122] (page 15).

SPEN have developed extensive experience in the acquisition and analysis of detailed data from the lower network voltage levels. Learning on secondary substation load profiles has provided enhanced understanding of risk and a new planning approach has been developed that should be moved to BAU in order to unlock capacity from existing assets. SPEN state they will look to deploy enhanced monitoring in a reactive way; however, they have identified the need for a new intermediary monitoring approach that flags the need for enhanced monitoring.

Smart MDIs are to be developed and deployed at all new secondary substations and at key location across the LV network as identified by the SPEN LCT monitoring strategy. In known highly-constrained areas, detailed network monitoring will be deployed. The LCNF work itself has not developed the smart MDI as yet.

The Flexible Networks project also updated rules of thumb for characterisation of PV generation at LV that release about 25% of additional capacity for the connection of PV [73]. Learning on the impacts of PV supports that produced by WPD. SPEN have produced their own new connection guidelines for PV that should be moved to BAU in order to unlock capacity from existing assets. SPENs LCNF projects have not included smart metering.

9.1.5.1 Key Learning

The key learning published in the reporting referenced in this section is set out below.

Learning on Network Monitoring:

- Monitoring specifications should be consistent with required minimum accuracy and reliability, given consideration to scaling across the network at large volumes.
- Practical installation considerations are also important to ensure an efficient monitoring rollout programme.
- Heuristics based analysis is a powerful technique that can help identify network 'hot-spots' at an early stage.
- Detailed analysis of monitoring data for network trial sites can be used to develop and verify simple rules of thumb for application to the wider network.
- Development of a "common" library[35] will facilitate integration of analysis tools using the same data sources and underlying analysis techniques across planning, operations and connections business processes.

[35] a software based tool, or tools, that allows different users and business functions access to the same information and data processing

- It is critical to understand the risk associated with a data-based business decision in the context of rapid increases in future load growth and clustering.
- Metrics which provide a characterisation of the risk associated with a data-based decision should be incorporated.

Learning on Load:

- Smart MDI type monitors at secondary substations could provide a cost-effective alternative to conventional MDIs.
- Detailed LV monitoring is appropriate in areas of high load uncertainly, such as clusters of heat pumps, EV charging or PV generation.
- Consideration is given to detailed LV monitoring as a temporary installation, with the option to re-locate the equipment. This makes a significant difference to the business case.
- Data transmission through mobile data networks is not 100% reliable and so allowances must be made to manage this to maximise data availability.
- In general, loads should be modelled as constant current rather than the current practice of constant power, except when more detailed information related to the nature of the load is available.
- A more statistical and probabilistic approach to data analysis provides a much fuller characterisation of network behaviour, sensitivities and trends.

Learning on PV:

- Peak PV generation load factor was reduced from 100% to 90% for North Wales/Scotland.
- Daytime minimum load per domestic property assumption was increased from 200W to 300W during periods of peak PV generation.

9.1.5.2 BAU Assessment

<u>Enhanced Network Monitoring (11kV Feeders, Secondary Substations)</u>

The Flexible Networks project implemented significant 11kV instrumentation for enhanced network monitoring. Secondary substation monitoring solutions are well tested. A staged strategy including smart MDI has been proposed for ED1 deployment. Although the business case will depend on the specific application (need for visibility), deployment of network monitoring solutions should now be a BAU process. **BAU Score: 4.**

<u>Enhanced Network Visualisation</u>

Integrating LV network monitoring data into visualisation and management systems was piloted in the Flexible Networks project. This may form an area of further development during ED1 but is some way from BAU. **BAU Score: 1.**

<u>Enhanced Understanding of Load</u>

In Flexible Networks, new tools were developed for forecasting and risk characterisation using secondary substation data; however, from the reporting it is not fully clear the strategy for adopting this into BAU. **BAU Score: 2.**

<u>Enhanced Understanding of LCT</u>

New insight on PV generation has led to updated design rules and a new BAU connections process. **BAU Score: 4.**

9.1.6 ELECTRICITY NORTH WEST

The Low Voltage Network Solutions project set out to trial and develop procedures to install low voltage monitoring without customer interruptions on 200 distribution substations [123]. The monitoring data was used to obtain an improved understanding of LV load and network conditions. Extensive analysis of substation busbar voltages and harmonic distortion on feeders has been published. The work allowed an existing Load Allocation tool to be improved and moved to BAU. The project included significant amounts of academic input to develop detailed LV network modelling techniques and probabilistic planning methods.

Smart Street represents the culmination of extensive LV monitoring, visualisation and control innovation by ENWL [59] [60]. ENWL's capability for full LV visibility and automation is well advanced through the work of these projects. Although ENWL state that the installation of LV monitoring is now a BAU process for them, the extent of implementation is not yet clear. They state "*Electricity North West intends to develop a policy to target its LV monitoring towards those networks or feeders where LCT uptake suggests a problem might be more likely to occur*" [123] (page 68).

ENWL LCNF projects have not addressed smart metering. Their work has mainly focussed on achieving LV visibility without the use of smart meter data.

9.1.6.1 Key Learning

The key learning published in the reporting referenced in this section is set out below.

Learning on monitoring LV networks:

- Both line-to-neutral voltages and phase currents (or active and reactive power) at the head of the feeders should be monitored
- For performance evaluation of the network, the mean value of 10 minute sampling intervals (or close to this, e.g. 15 minutes) should be adopted to avoid (in particular) underestimating voltage impacts. For the monitoring of currents (or active and reactive power), hourly values are adequate. There is no significant benefit in adopting shorter sampling intervals (e.g. 1 or 5 minutes). If an operational solution with control is later adopted, sampling intervals can be adapted accordingly and could sometimes be longer.
- For voltage purposes, the end points of the corresponding feeders should be monitored given that the busbar would only work as a proxy if some knowledge of the feeders exists. Mid-points do not necessarily bring more critical information although they increase certainty and observability. However, for congestion purposes, currents at the head of the feeders should be monitored
- The monitoring devices to be deployed, particularly at the substation, should ideally also monitor total harmonic distortions of voltage and neutral currents, given that high penetrations of LCT are likely to exacerbate these issues

Learning from LV monitoring data:

- 15% of monitored substations were found to have some limited reverse power flow.
- Busbar voltages: the daily average voltages with 10 minute sampling varied between 237V and 253V. Most substations (63%) have a daily average voltage between 241V and 248V.
- For the majority of substations (93%) the difference between maximum and minimum busbar voltage was less than 11.5V.
- The monitoring found significant variation in the average current THD per feeder varied between 2% and 98%, although most feeders (65%) were found to have between 10% and 20% average current THD. The average current THD increased significantly in feeders with PV, particularly for feeders where more than 30% of customers have PV.

- A change was made to the default power factor assumption from 0.95 to 0.98 in the company's existing 'Load Allocation' algorithm
- A Future Capacity Headroom (FCH) model of the ENWL LV and HV network has been built.
- Three-phase four-wire modelling is required at LV. The utilisation of single-phase (balanced) network and load representations was found to underestimate the impacts of LCT in LV networks.
- Due to the BSEN50160 standard, analyses carried out with intervals longer than 10 minutes are likely to underestimate voltage impacts.

Learning on network visualisation:

- A Future Capacity Headroom (FCH) model of the ENWL LV and HV network has been built.
- Three-phase four-wire modelling is required at LV. The utilisation of single-phase (balanced) network and load representations was found to underestimate the impacts of LCT in LV networks.
- Due to the BSEN50160 standard, analyses carried out with intervals longer than 10 minutes are likely to underestimate voltage impacts.

Learning on LCT:

- A probabilistic analysis of future LCT scenarios on detailed LV models is a valuable scenario planning tool.
- As LCT uptake may not necessarily lead to a network problem, an approach which monitors first rather than intervenes is justified. Suitable correlation metrics should be adopted to find the most suitable penetration level of a given LCT for a feeder or LV network for which monitoring is required.

9.1.6.2 BAU Assessment

<u>Enhanced Network Monitoring (Secondary Substations and LV Feeders)</u>

Enhanced LV network monitoring solutions have been widely deployed by ENWL. Although the business case will depend on the specific application (need for visibility), deployment of network monitoring solutions should now be a BAU process. **BAU Score: 4.**

<u>Enhanced Network Visualisation</u>

ENWL projects have focussed heavily on developing LV modelling and visualisation and automation solutions. The final results of Smart Street will be critical to determining the business case for widespread deployment. Further development of these solutions is expected in ED1 innovation projects. The LV network modelling work reviewed has indicated some benefits; however, it has been primarily an academic exercise and the DNO intention to adopt as BAU is unclear. **BAU Score: 1.**

<u>Enhanced Understanding of Demand</u>

Analysis of monitoring data has updated ENWL understanding of load at secondary substations and new modelling and planning tools are identified as ED1 innovation activities. **BAU Score: 3.**

<u>Enhanced Understanding of LCT</u>

New probabilistic planning methods have been developed for LCT; however the reporting indicates this has been a largely academic exercise and it is not clear if this will be developed further towards BAU. **BAU Score: 1.**

9.2 Discussion

Enhanced Network Monitoring

The vast majority of network monitoring activity has focussed on 11kV feeders, secondary substations and LV feeders. These projects can be split into two groups: 1) projects that specifically addressed the technical challenge of monitoring lower voltage networks as their core objective; and 2) projects that required monitoring solutions to support wider objectives. The first group of projects occurred in the initial stages of the LCNF and culminated in the joint WPD/UKPN project LV Current Sensor Technology Evaluation. From the second group of projects, those that commenced in the early stages of the LCNF either draw on Tier 1 project learning and/or undertake their own learning process on how best to meet their monitoring needs.

Enhanced Network Visualisation

Data acquisition in LCNF projects has been undertaken in many cases as a one-off exercise in order to support testing and validation of new solutions. In other cases, the gathering, processing and utilising data is a core feature of the innovation. Where the data is brought back to a centralised location (control room) new tools and systems have been developed that allow the analysis and visualisation of the data. These may be linked to the existing Network Management System or may be stand alone. Work in this area centres around building capability to build detailed network models of 11kV and LV network areas that can then be populated by data, either in near real-time for distribution state estimation that in turn enables control decisions, or retrospectively for longer term planning studies.

Improved Understanding of Existing Demand and LCT

Many projects have gathered data in order to update the current industry understanding of demand for planning applications. By gaining access to large quantities of smart meter data, either by partnering with early electricity supply company deployments or by deploying project specific metering to represent expected future smart meter functionality, projects have explored the ways in which smart meter data can be used by DNOs. The majority of activity has been on updating existing planning methods with new design assumptions (ADMD values or profiles), rather than developing entirely new planning methods based on more advanced analysis of load. Projects have also investigated the load characteristics of LCT loads such as Electric Vehicles and Heat Pumps, as well as investigating the generation characteristics of residential PV. This includes developing ways to represent this new load and generation that exists 'behind the meter' within existing planning tools and also developing new planning methods for LCT.

9.3 BAU Overview

An overview of the BAU scores is provided in Figure 34 and Figure 35.

All DNOs have developed their capability to extend enhanced network monitoring throughout the network and this should be a BAU process for all DNOs now. The business case for deployment is linked to the need to reduce uncertainty or support another innovation that requires network visibility. As such the consensus is that enhanced monitoring will be deployed as LCT penetration or innovation projects require it. Some early learning has taken place on the development of network visualisation tools. The evidence indicates some value here but is linked to a more general shift to an area or centralised control architecture for which the business case has yet to be made.

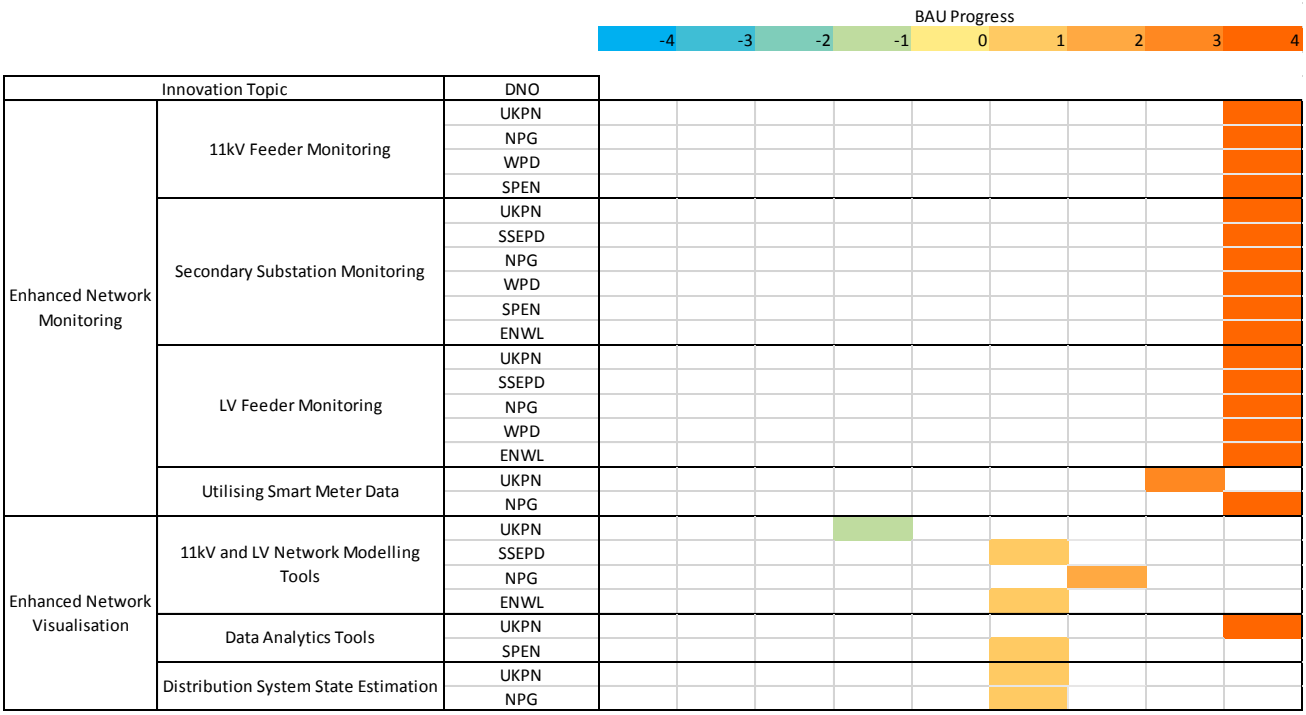


Figure 34: BAU Assessment for Network Monitoring and Visualisation Projects

An updated understanding of secondary substation loading and residential load profiles suitable for standard design process has been obtained by several projects. These should be adopted as BAU. Other projects have focussed on more ambitious work that seeks to develop more detailed probabilistic understanding of which has yet to close and report fully at the time of this review.

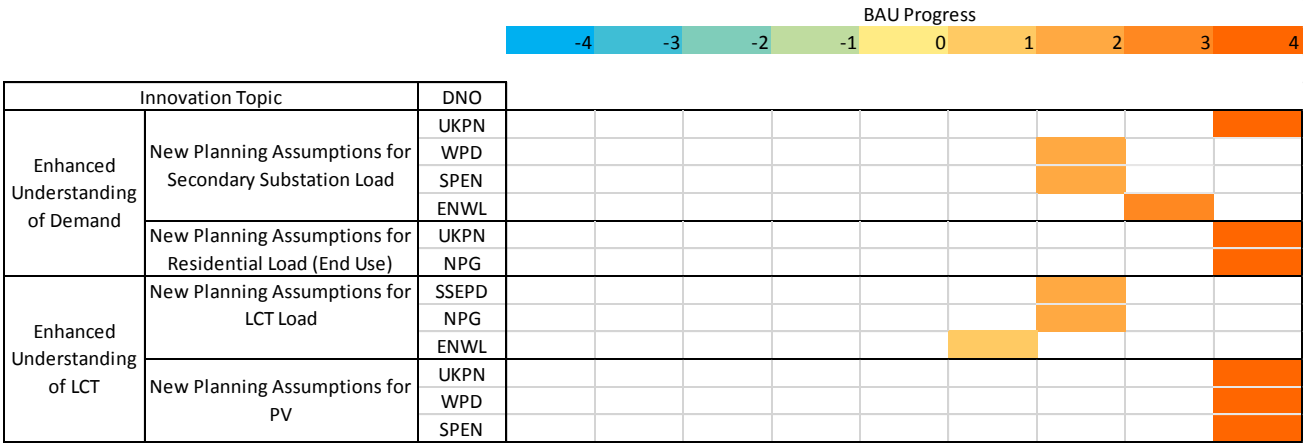


Figure 35: BAU Assessment for New Planning Assumptions

9.4 Synthesis of Learning

The synthesis of learning and associated recommendations derived from the review in this section are set out below.

<u>Enhanced Network Monitoring</u>

Learning:

- The ability to deploy enhanced monitoring across the network should now be a BAU process for all DNOs.

- There is no strong business case for enhanced permanent monitoring alone; it is an enabler for other innovation or to remove uncertainty caused by LCT penetration.
- Detailed recommendations on network monitoring requirements and best practice have been made by several projects.
- In respect of strategies for staged deployment of network monitoring and optimal use of network data, approaches and recommendations vary between DNOs.
- A variety of communication network solutions have been trialled with results displaying a range of performance and reliability across the different technologies.

Recommendations:

- Collaborative efforts should be undertaken by the DNO community to consolidate the various findings and establish industry best practice for network monitoring technology and communication network solutions.
- Collaborative efforts should be undertaken by the DNO community to consolidate strategy recommendations and establish best practice on network monitoring strategy.

<u>Enhanced Network Visualisation</u>

Learning:

- Capabilities for detailed modelling of distribution networks, down to LV cut-outs, have been developed and many different load flow packages with varying functionality have been utilised.
- Detailed modelling has encountered many challenges including: accuracy of asset records, translation of asset records into suitable data formats, integration of new tools into existing systems and databases and availability of suitable commercial packages for new analysis requirements.
- Distribution System State Estimation (DSSE) has been tested – further work is required to improve functionality and improve accuracy.
- New data analytics tools have been developed that integrate monitoring data with existing GIS and asset management systems.

Recommendations:

- Collective experience on distribution network modelling tools should be established with a comparative analysis of functionality and data and integration challenges.
- DSSE is a requirement for area control systems and should remain an innovation priority area.
- There is opportunity for further knowledge sharing to fully demonstrate prototype visualisation tools and communicate potential applications and benefits.

<u>Improved Understanding of Existing Demand</u>

Learning:

- New ADMD values, customer categorisations and DEBUT planning profiles are now available along with enhanced LV substation load profiling; however, methods and recommendations vary between projects.
- The improved understanding of load from several projects indicates that additional capacity can be released under existing planning methods and policy; however, results vary between projects.
- Although an updated understanding of load has obvious value, essentially the new load profiles follow expected patterns and look very similar to legacy profiles. More advanced, probabilistic methods of modelling and forecasting load have had limited attention – advanced planning techniques are likely to be required but are in very early stages of development.

- The focus of LCNF project activity indicates that a main application DNOs see for smart meter data is the periodic updating of load profiles for current planning and design methods.
- Several projects have deployed 'End Point Monitoring' to simulate access to smart meter data for operational purposes.
- There appears to be a risk that either DNO value from more dynamic access to smart meter data is proven but not permitted by current policy/functionality and hence duplicate metering is required; or DNO value from more dynamic access to smart meter data is not properly explored as DNOs believe current policy/functionality will not enable it to be realised anyway.

Recommendations:

- There is an opportunity to bring together the data sets and new insights related to load and planning in order to establish new industry standards and ensure all DNOs are able to fully exploit existing network capacity.
- Whilst current planning and design methods can be usefully updated by LCNF insights, the use of initial LCNF work on new planning and design methods should be an innovation priority going forward, assessing the benefits of utilising extensive quantities of data for more complex probabilistic planning and design, in place of deterministic methods.
- The use of 'End Point' data for operational purposes should remain an innovation priority in order to establish any benefits and demonstrate either a business case for DNO owned metering additional to smart meters or to highlight the need for augmented DNO access to smart meters.

<u>Improved Understanding of LCT</u>

Learning:

- New ADMD values and planning profiles are now available for EV, heat pumps and solar PV.
- Findings on LCT ADMD and planning profiles are from relatively small sample sets – further work to characterise LCT demand for robust planning will be necessary as deployments increase.
- A consensus appears to be building on PV output diversity and updates to planning policy that can release immediate capacity.

Recommendations:

- Insight into LCT demand and impact is limited by lack of practical experience due to current low penetration levels. Continually updating understanding of LCT and incorporating it into planning and design methods should remain a priority for the DNOs.
- Further collaboration should take place to establish a consensus on appropriate PV connection policy that should become BAU for the sector in the immediate future.

10 Summary of Main Findings

The key learning and recommendations from each synthesis theme are consolidated in this section. The BAU assessment for each synthesis theme is also summarised. A median value and range of scores is provided for each innovation to represent the aggregate BAU position across all the DNOs. The median BAU score is represented by the location on the BAU scale of the coloured bar. The size of the bar represents the relative amount of project activity in this area and the high-low lines indicate the range of scores across the relevant projects.

10.1 Battery Energy Storage

Key Learning:

- Technical proof of concept for power flow management and voltage support applications has been demonstrated by multiple projects.
- The technology is still evolving and field experience has been valuable to uncover the difference between theoretical (modelled) and practical operation characteristics.
- Round trip efficiencies as low as 40% have been observed[36].
- Auxiliary power requirements are a significant factor in reduced efficiency performance.
- Charge/discharge characteristics can vary significantly between units of the same technology.
- Accurately measuring and modelling State of Charge has been problematic in practice and is a major challenge for battery life cycle management.
- Where business case analysis is provided by the projects, costs are currently unjustifiable when only DNO network reinforcement deferral is considered; where multiple hypothetical revenue streams are considered, a positive cost-benefit analysis (CBA) is sometimes achieved.
- Large scale battery storage may be an attractive, flexible solution for DNOs if it can be contracted from 3rd parties; however, a viable business case for 3rd parties remains to be demonstrated.
- Small scale distributed storage may become an attractive solution as technical understanding and control methods develop; however, costs are still prohibitive.

Recommendations:

- Given the reported technical, commercial and regulatory challenges with large-scale storage, DNO innovation efforts should not focus on DNO owned and deployed storage, but on supporting the necessary industry developments and commercial model evolution that allow DNOs to tender, on a technology neutral basis, for flexibility services.
- An exception to the above is smaller-scale distributed storage deployed at secondary substations and LV feeders. Further evidence on the value such storage can provide through voltage support, peak shifting and phase balancing functionality – combined with tracking of market developments and cost reductions – is needed to allow robust business case analysis.

Understanding the most appropriate approaches to the control of smaller scale distributed storage (e.g. real-time versus forecast and schedule, or local versus coordinated) should remain a research and innovation priority.

The BAU summary is shown in Table 24 below.

[36] Although a direct comparison with expected (manufacturer rated) efficiency is not provided in most cases, the general trend is that although battery charge/discharge efficiencies are claimed to be upwards of 80%, the full round-trip efficiency including parasitic power requirements is often significantly less.

Learning Topic	Innovation	BAU Score -4 -3 -2 -1 0 1 2 3 4
Storage for Power Flow Management and Voltage Control	Large Scale Batteries	
	Distributed Small Scale Batteries	

Table 24: Summary of BAU Scores for Storage Innovations

10.2 Flexible Demand

Key Learning:

- Voltage reduction to achieve general demand reduction has been demonstrated successfully; all DNOs should consider the application of this as a BAU option.
- The C2C project's solution for managed flexible connection of I&C demand should also be considered as a BAU option by all DNOs.
- On-demand dispatch of I&C demand (call-off contracts) has been successfully trialled and should be progressed to a BAU option by all DNOs. Challenges remain to reduce uncertainty around reliability, CBA and acceptable risk for post-fault flexible demand.
- Residential Time of Use tariffs have shown limited potential in the LCNF trials. Although some peak reduction was achieved, the solution was deemed unlikely to provide sufficient benefit to avoid network reinforcement.
- Residential direct demand control trials also achieved limited network benefits.
- As trialled in LCNF projects, residential flexible demand is unlikely to be a solution deployed by DNOs although if rolled out by suppliers, DNOs may derive some benefit.
- LCT direct control has shown good potential; however, trials are for relatively small numbers and the technology is at early stages of development.

Recommendations:

- Further collaborative efforts to establish best practice in voltage reduction and the potential for offering frequency response should be undertaken by the DNO community.
- Further dissemination of the C2C method should be undertaken with all DNOs formally assessing its potential for their network areas.
- Collaborative efforts to establish industry best practice for I&C flexible demand should be undertaken addressing:
    - The geographical nature of flexible demand requirement.
    - The best methods of contracting flexible demand.
    - Improved understanding of reliability and appropriate planning methods.
- Data-sets from the LCNF I&C trials should be consolidated in order to provide further insight to appropriate methods of accounting for flexible demand within industry security of supply standards and to identify further work required to improve the understanding of risk for post-fault flexible demand.
- New methods of harnessing the potential of residential demand response should remain an innovation priority in parallel with efforts to establish the necessary frameworks with suppliers to enable DNOs to access this resource.
- LCT direct control should remain an innovation priority, developing the technical and commercial understanding of such solutions, in addition to the development of appropriate planning tools in readiness for significant LCT adoption.

The BAU summary is shown in Table 25 below.

Learning Topic	Innovation	BAU Score
Flexible Demand for Power Flow Management	Voltage Optimisation	
	Industrial & Commercial Managed Connections	
	Industrial & Commercial Call Off Contracts	
	Residential Time of Use Tariffs	
	Residential Appliance Control	
	Residential LCT Control	
	Community Engagement	

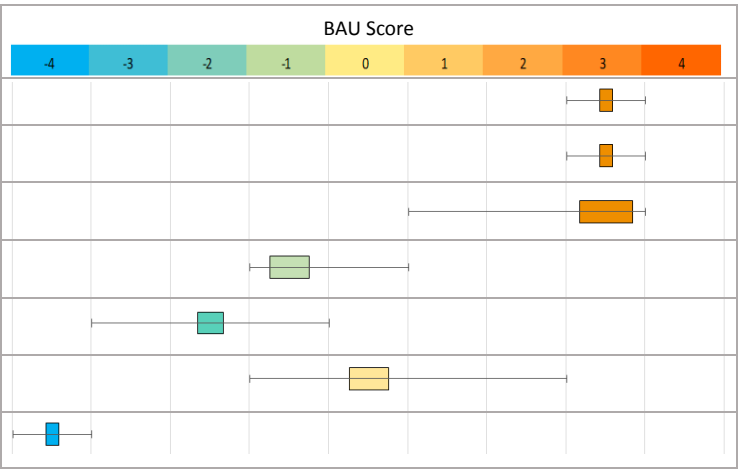


Table 25: Summary of BAU Scores for Flexible Demand Innovations

10.3 Generator Control

Key Learning:

- Active Network Management for DG connections should be a BAU option for all DNOs.
- The ANM solution has matured; extensive experience has been garnered and shared.
- DNOs have collaborated to produce an ANM best practice guide.
- Templates of commercial documents[37], planning tools and stakeholder engagement and information tools are now well-developed.
- The deployments are predominately stand-alone, local solutions based on measurement of pre-identified constraints, with control of generator output based on a Last in First Out commercial model.
- Pro-rata commercial models were trialled successfully and found to offer improved efficiency in maximising connected generation for specific constraint scenarios.
- Pro-rata was found to be suitable for reverse power flow constraint on grid substations; however, it was deemed technically unsuitable for more complicated situations with multiple constraints.
- Contracting with an aggregator for temporary installation of DG, i.e. seasonal deployment such as of diesel generators during the winter, was found to be technically and commercially unviable.
- The understanding of DG contribution to security of supply has been progressed and new data produced that can inform review of ETR130/131 and the current review of ER P2/6.

Recommendations:

- Detailed analysis of the ANM route to BAU, and the role of innovation funding at different stages in the process should be undertaken to inform future innovation project direction and policy for the development of other promising technologies.
- ANM solutions that account for and utilise load 'behind the meter' should be an ongoing innovation focus (depending on results from SPEN's ARC project).
- Alternative technical and commercial solutions and the transition to more coordinated, integrated wide area control should remain an innovation priority.
- There is the opportunity for a collaborative effort that utilises all relevant data from numerous LCNF projects (and other DG projects) to provide further insight into DG contribution to security of supply and to update ETR 130/131.

[37] Standardised connection agreements, offer letters, terms and conditions, etc.

The BAU summary is shown in Table 26 below.

Learning Topic	Innovation	BAU Score (-4 -3 -2 -1 0 1 2 3 4)
Generator Control for Power Flow Management and Voltage Control	Actively Managed DG Connections	
	Seasonal Generation Deployment	

Table 26: Summary of BAU Scores for Generator Control Innovations

10.4 Network Configuration

Key Learning:

- In the cases assessed, interconnection at 33kV has been shown to have insufficient benefit to justify deployment.
- Interconnection between 11kV substations has been shown to have significant potential for cost-effective release of network capacity by the Flexible Network Connections project; however, some contrary evidence is provided by the FALCON project.
- Justification for interconnection and automation at LV has yet to be proven; however, significant projects in this area are yet to close and report fully.
- Smart Fuse technology for LV networks has shown significant potential and should be considered as a BAU option.

Recommendations:

- Further work on 11kV interconnection is carried out to enhance the evidence base and confirm the potential of the solution as a BAU option for all DNOs.

The BAU Summary is shown in Table 27 below.

Learning Topic	Innovation	BAU Score (-4 -3 -2 -1 0 1 2 3 4)
Network Configuration for Power Flow Management and Protection	33kV Interconnection	
	11kV Interconnection	
	LV Interconnection	
	LV Smart Fuse	

Table 27: Summary of BAU Scores for Network Configuration Innovations

10.5 Equipment for Active Regulation of Voltage

Key Learning:

- Voltage reduction at primary substations has been demonstrated as an effective method of releasing 'headroom' capacity that can also, depending on the nature of the load, potentially reduce energy consumption. This should be considered as a BAU option by all DNOs (revision of grid code stipulations may be required).
- Suggested approaches to voltage reduction vary between DNOs:
    - A permanent reduction of 1%;
    - Seasonal reduction up to 3%;
    - Local control by Load Drop Compensation up to 3%;
    - Coordinated control by a wide area control scheme.
- Dynamic control of voltage reduction has been noted to open the possibility of DNO provision of balancing services to National Grid.

- Enhancing automatic voltage control (AVC) functionality for primary substations via relay upgrade, additional control capability and enabling remote configuration, allows improved local control and is a key enabler for area coordinated voltage control.
- Deployment of secondary substation OLTC has been shown to release significant 'legroom'; however, there is debate on whether a positive CBA can be built versus LV re-cabling[38].
- HV Automatic Voltage Regulators (AVRs) are a useful enabling technology for flexible networks.
- D-STATCOM devices have demonstrated effective voltage control; however, issues are reported around costs and practical aspects of implementation.
- Results indicate the coordinated control of multiple voltage management devices across the network enables full value (increased network capacity) to be realised; however, this has only been partially demonstrated and is deemed difficult and too complex at present.
- The deployment of many controllable devices at all voltage levels requires coordination via area control schemes. The previous statement on complexity and necessity of such schemes, plus outputs on voltage management strategy by projects, indicate that although some of this voltage control equipment may be deployed in isolated, case-specific circumstances, limited additional control will be deployed beyond primary substations in the foreseeable future.

Recommendations:

- There is an opportunity for further knowledge sharing and collaborative efforts to establish best practice for voltage reduction. This should include further detailed technical work on associated issues including trends in the voltage dependency of loads, circulating currents and relay hunting.
- Additional to any upgrades required to deliver voltage reduction, enhanced voltage control functionality for primary substations should be considered as a standard deployment as a key enabler for future voltage control strategies.
- Innovation work should focus on proving/improving the business case of secondary substation OLTC against LV reinforcement.
- There is an opportunity for further knowledge sharing and collaborative efforts to establish best practice for HV Automatic Voltage Regulator applications.
- Further innovation in respect of voltage regulation should focus on the required coordination and control architectures (boundaries between local and centralised control, and coordinated management of thermal and voltage constraints) rather than being approached solely from a kit-testing perspective.

The BAU summary is shown in Table 28 below.

Learning Topic	Innovation	BAU Score (-4 … 4)
Equipment for Active Regulation of Voltage	Voltage Reduction	
	Primary Substation Enhanced AVC	
	Secondary substation OLTC	
	Voltage Regulators	
	Switched Capacitors	
	D-STATCOM	

Table 28: Summary of BAU Scores for Equipment for Active Regulation of Voltage

[38] Although some additional footprint requirements were noted in the trial installations, secondary OLTC transformer sizes have not been highlighted as a barrier to deployment by these projects.

10.6 Real Time Thermal Ratings

Key Learning:

- Results reveal that in general, static ratings are not always as conservative as had been commonly assumed and RTTR can be less than the static rating more often than expected by the existing standards.
- There are conflicting statements on the need for dynamic ratings; deployments of monitoring to calculate enhanced static ratings have been proposed as sufficient.
- RTTR for 132kV and 33kV overhead lines is well tested by LCNF projects.
- Average uplift for 33kV OHL is in the order of 10-15%.
- There are conflicting conclusions on the issue of sheltering for 33kV OHL RTTR.
- 33kV OHL RTTR or enhanced ratings can unlock capacity and should move to BAU, particularly with ANM for DG connections.
- RTTR for primary transformers was shown to enable 30% increase in peak loading above nameplate by modelling in one project; however, trials were limited to 10% by other asset capacity issues. Other projects had less conclusive results; however, in general, results suggest an uplift of 10% is achievable.
- RTTR for 11kV OHL, underground cables and distribution transformers requires further work – some benefits have been observed, but issues such as rapid variability and improved thermal modelling need to be addressed.

Recommendations:

- There is an opportunity for further knowledge sharing and collaboration to establish industry best practice on 33kV OHL RTTR.
- Learning and experiences from across the projects on RTTR for 11kV OHL, underground cables and transformers should be further reviewed and consolidated, with a view to establishing the most appropriate further innovation work for RTTR or bespoke enhanced ratings of these assets.

The BAU summary is shown in Table 29 below.

Learning Topic	Innovation	BAU Score (-4 -3 -2 -1 0 1 2 3 4)
Real Time Thermal Ratings (RTTR)	33kV Overhead Line RTTR	
	11kV Overhead Line RTTR	
	Underground Cable RTTR	
	Underground Cable RTTR	

Table 29: Summary of BAU Scores for Real Time Thermal Ratings Innovations

10.7 Enhanced Network Monitoring

Key Learning:

- The ability to deploy enhanced monitoring across the network should now be a BAU process for all DNOs.
- There is no strong business case for enhanced permanent monitoring alone; it is an enabler for other innovation or to remove uncertainty caused by LCT penetration.
- Detailed recommendations on network monitoring requirements and best practice have been made by several projects.
- In respect of strategies for staged deployment of network monitoring and optimal use of network data, approaches and recommendations vary between DNOs.

- A variety of communication network solutions have been trialled with results displaying a range of performance and reliability across the different technologies.

Recommendations:

- Collaborative efforts should be undertaken by the DNO community to consolidate the various findings and establish industry best practice for network monitoring technology and communication network solutions.
- Collaborative efforts should be undertaken by the DNO community to consolidate strategy recommendations and establish best practice on network monitoring strategy.

The BAU summary is shown in Table 30 below.

Learning Topic	Innovation	BAU Score (-4 -3 -2 -1 0 1 2 3 4)
Enhanced Network Monitoring	11kV Feeder Monitoring	
	Secondary Substation Monitoring	
	LV Feeder Monitoring	
	Utilising Smart Meter Data	

Table 30: Summary of BAU Scores for Enhanced Network Monitoring Innovations

10.8 Enhanced Network Visualisation

Key Learning:

- Capabilities for detailed modelling of distribution networks, down to the customer point of connection, have been developed and many different load flow packages with varying functionality have been utilised.
- Detailed modelling has encountered many challenges including: accuracy of asset records, translation of asset records into suitable data formats, integration of new tools into existing systems and databases, and availability of suitable commercial packages for new analysis requirements.
- Distribution System State Estimation (DSSE) has been tested – further work is required to improve functionality and improve accuracy.
- New data analytics tools have been developed that integrate monitoring data with existing GIS and asset management systems.

Recommendations:

- Collective experience on distribution network modelling tools should be established with a comparative analysis of functionality and data and integration challenges.
- DSSE is a requirement for area control systems and should remain an innovation priority area.
- There is opportunity for further knowledge sharing to fully demonstrate prototype visualisation tools and communicate potential applications and benefits.

The BAU summary is shown in Table 31 below.

Learning Topic	Innovation	BAU Score (-4 -3 -2 -1 0 1 2 3 4)
Enhanced Network Visualisation	11kV and LV Network Modelling	
	Data Analytics Tools	
	Distribution System State Estimation	

Table 31: Summary of BAU Scores for Enhanced Network Visualisation Innovations

10.9 Improved Understanding of Existing Demand

Key Learning:

- New ADMD values, customer categorisations and DEBUT planning profiles are now available along with enhanced LV substation load profiling; however, methods and recommendations vary between projects.
- The improved understanding of load from several projects indicates that additional capacity can be released under existing planning methods and policy; however, results vary between projects.
- Although an updated understanding of load has obvious value, essentially the new load profiles follow expected patterns and look very similar to legacy profiles. More advanced, probabilistic methods of modelling and forecasting load have had limited attention – advanced planning techniques are likely to be required but are in very early stages of development.
- The focus of LCNF project activity indicates that a main application DNOs see for smart meter data is the periodic updating of load profiles for current planning and design methods.
- Several projects have deployed 'End Point Monitoring' to simulate access to smart meter data for operational purposes.
- There appears to be a risk that either DNO value from more dynamic access to smart meter data is proven but not permitted by current policy/functionality and hence duplicate metering is required; or DNO value from more dynamic access to smart meter data is not properly explored as DNOs believe current policy/functionality will not enable it to be realised anyway.

Recommendations:

- There is an opportunity to bring together the data sets and new insights related to load and planning in order to establish new industry standards and ensure all DNOs are able to fully exploit existing network capacity.
- Whilst current planning and design methods can be usefully updated by LCNF insights, the use of initial LCNF work on new planning and design methods should be an innovation priority going forward, assessing the benefits of utilising extensive quantities of data for more complex probabilistic planning and design, in place of deterministic methods.
- The use of 'End Point' data for operational purposes should remain an innovation priority in order to establish any benefits and demonstrate either a business case for DNO owned metering additional to smart meters or to highlight the need for augmented DNO access to smart meters.

The BAU summary is shown in Table 32 below.

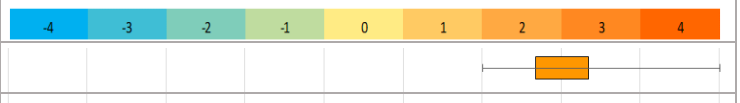
Learning Topic	Innovation	BAU Score (-4 to 4)
Improved Understanding of Existing Demand	New Planning Assumptions for Substation Load	
	New Planning Assumptions for Residential Load	

Table 32: Summary of BAU Scores for Innovations on Improved Understanding of Existing Demand

10.10 Improved Understanding of LCT

Key Learning:

- New ADMD values and planning profiles are now available for EV, heat pumps and solar PV.
- Findings on LCT ADMD and planning profiles are from relatively small sample sets – further work to characterise LCT demand for robust planning will be necessary as deployments increase.
- A consensus appears to be building on residential PV output diversity and updates to planning policy that can release immediate capacity.

Recommendations:

- Insight into LCT demand and impact is limited by lack of practical experience due to current low penetration levels. Continually updating understanding of LCT and incorporating it into planning and design methods should remain a priority for the DNOs.
- Further collaboration should take place to establish a consensus on appropriate PV connection policy that should become BAU for the sector in the immediate future.

The BAU summary is shown in Table 33 below.

Learning Topic	Innovation	BAU Score -4 -3 -2 -1 0 1 2 3 4
Improved Understanding of LCT	New Planning Assumptions for Electric Vehicles and Heat Pumps	
	New Planning Assumptions for Residential PV	

Table 33: Summary of BAU Scores for Innovations on Improved Understanding of LCT

11 Reflections on Implementation and Reporting of LCNF Projects

Despite some criticisms, expanded on below, our review has revealed many projects that, on the basis of the evidence they have published, appear to have been well run and have made significant strides forward in the current state of knowledge. The collective position of the DNOs with respect to innovation when the LCNF was introduced should be kept in mind [2, 6]. They had very little recent experience of specifying and managing the kind of research and development (R&D) or demonstration activities required to address the uncertainties inherent in innovation. We are confident that they have much better capability now with respect to R,D&D and its reporting than they did at the beginning. In addition to the knowledge gained within each of the themes we have identified, we believe that this, in itself, is a major success of the LCNF.

The stated objective of the LCNF was *to help DNOs understand how they provide security of supply at value for money and facilitate transition to the low carbon economy* [1]. The LCNF Governance arrangements state that projects should focus on the trialling of: new equipment (more specifically, that unproven in GB), novel arrangements or applications of existing equipment, novel operational practices, or novel commercial arrangements [1]. Tier 1 projects were specifically required to have a Technology Readiness Level[39] (TRL) between 5 and 8. TRL 9 was excluded, as projects with this TRL were thought to be too low risk and offer limited scope for new knowledge to be generated. TRLs were not specifically mentioned in the governance for Tier 2 projects. However, the requirements for Tier 2 projects stated that projects should be neither at the R&D stage nor involve the widespread deployment of proven technology or practices. Instead, the guidance stated that methods being trialled should be "untested at the scale and circumstance in which the DNO wishes it to be deployed and that consequently new learning will result from the project". Since the adopted definition of TRLs defines R&D as TRLs 1-5, this guidance implies Tier 2 projects should be at TRL 6 or above, i.e. demonstration and early deployment.

In December 2015, Ofgem started a consultation on the governance arrangements for current distribution network innovation mechanisms [3]. Respondents highlighted that LCNF success is often discussed in terms of the diffusion of the trialled innovation into BAU [4, 5]. With the funding guidance focussing on demonstration, a certain amount of diffusion to BAU could indeed be anticipated and associating this with success is perhaps unavoidable. In addition, the balance of risk and reward for projects was noted to hinge on 'successful delivery' [7] with recovery of 10% of project costs dependent on retrospective assessment of Successful Delivery Reward Criteria (SDRC).

Our interpretation of these aspects of the LCNF mechanism is that they either encouraged incremental, conservative projects with the purpose of demonstrating high TRL (8-9) solutions, or influenced projects that included earlier TRL innovation to implement and report the project as though demonstrating high TRL (8-9) solutions. Many Tier 2 projects feature a range of methods and solutions with varying TRLs, yet the project design and learning methodologies do not necessarily reflect this. Although very large amounts of useful learning have been generated and most projects have met Ofgem's requirements to provide a methodology for learning and dissemination, we find that robust evidence regarding the innovations explored is sometimes lacking. While this can be due to unanticipated problems that should be addressed before any firm conclusion can be drawn, in a number of cases this would appear to have been due to poor initial design of experiments where there was a failure to clearly state what information is sought and to define robust methods to obtain it. In some projects, we also observe a failure to position a project relative to current levels of knowledge (or TRL), the expected evidence that should be generated by the trial, and finally, what level of knowledge is to be obtained by the end of the project. It is our impression that DNOs have shown

[39] The definition of TRLs used by Ofgem are taken from the UK Low Carbon Energy Technology Strategy: September 2008 available at http://webarchive.nationalarchives.gov.uk/20090609003228/http://www.berr.gov.uk/files/file47575.pdf

some reticence to report innovations that have not performed as expected and that the publication of sufficient data and information to allow others to try to reproduce the results and test the conclusions has been highly variable. We speculate that this could be due to: inexperience of some DNO personnel with management of R&D and scientific reporting; a focus in some cases on 'success' as meaning that what was being investigated in a project turns out to be something that can and should be adopted; or the nature of the competition between DNOs that has been fostered by Ofgem.

Based on the stated focus on *improved understanding,* we believe that the success of an LCNF project, once funded, should be judged on the quality of evidence generated. The evidence may actually indicate the rejection of the innovation, or the need for further work. For high TRL innovations, the evidence should allow robust decisions to be made regarding the viability and cost-effectiveness of the innovation and the conditions under which its deployment is justified. Similarly, projects that provide robust, credible evidence that a lower TRL innovation remains promising and requires further work, or should be dropped, should also be regarded as successes.

In respect of the transition of innovation from LCNF projects to BAU, not only as an option but also in actual deployment in the near term, we have found limited evidence of success. In certain projects, where the focus has clearly been on a high TRL solution, this has been achieved; however, in many cases, it has not. We believe this reflects the lower TRL of many of the innovations trialled. We also observe that many projects included prototype development and academic modelling, suggesting work at lower TRLs than set out in the LCNF governance. We do not see the focus on lower TRL innovation and lack of transition to BAU as a negative per se; the critical aspect is the quality of evidence that can be expected and what kinds of decisions this subsequently informs, as discussed above.

For those projects focussing on high TRL solutions (such as: improving voltage management and rolling out well understood ANM solutions) our opinion is that there was a clear business need. Where a significant level of uncertainty around the operation or roll out cost was not apparent, a question arises: was innovation funding necessary?

Questions around a particular technology not previously used by the DNOs in Britain may be summarised as follows:

1. What features does it offer for operation of the network?
2. How does it behave in detail once installed on a distribution network, and how can it be installed and operated?
3. In what situations might it be useful and potentially prove economically attractive, and on what does a positive business case appear to depend?

It seems to us that, in respect of a number of technologies, a network operator should already have good knowledge in respect of the first question above or might have acquired it through a suitable Tier 1 project before advancing to Tier 2. However, this question has been addressed by some Tier 2 projects.

Pursuit of answers to question 2 may have sought to address a particular DNO's lack of experience with a technology rather than the GB sector's lack of experience. However, this can nevertheless provide valid and useful learning that might not have been gained without LCNF. (Very often, operational issues associated with some equipment or a process only come to light when it is tried in a realistic situation).

In respect of question 3, in our opinion, it has not always been necessary to deploy technology at the scale that it sometimes has in order to gain valid answers, e.g. in projects involving batteries. In a number of projects, technical viability of a solution has somewhat been established but the system conditions under which use of the technology would be justified have not yet arisen, e.g. significantly more connected DG or

increased demand such as for EV charging or more electric heating. Nonetheless, the learning here should prove useful – as seen in the south of England in the last year with an unexpectedly rapid growth of solar PV, changes can happen quite quickly and the DNOs should be ready with a range of options to manage them adequately and with confidence. Work on these options ahead of need is therefore entirely justified.

Our view is that support for high TRL demonstration projects is required to avoid the 'regulatory valley of death' [6], but that support should appropriately reflect the relatively small risk to the DNO. In addition, innovation support should also provide for lower TRL projects with acknowledgement of the high degree of uncertainty and risk. Success for these projects should primarily be assessed on the level of new knowledge gained, i.e. the reduction of uncertainty. The project design and reporting for large Tier 2 projects should acknowledge the range of TRLs among the core methods and solutions being trialled. The methodology for learning and dissemination should be appropriate to each TRL and, crucially, should not inhibit learning from failure.

12 Conclusions

The learning from LCNF projects undoubtedly leaves the DNOs in Britain with a better understanding of the challenges and potential solutions for networks during the low carbon transition.

Battery Energy Storage has been tested at both large and small (distributed) scale with valuable learning generated on the practical deployment aspects in addition to the details of operation when connected to real distribution networks. The challenges around the commercial, legal and regulatory aspects of battery storage have been identified, if not solved, and an understanding has developed of storage as a flexible service to be contracted rather than an asset to be owned.

New options for utilising flexible demand via voltage management and control of I&C customers has been developed to an extent that is viable for further deployment. Trials on residential flexible demand have demonstrated that further innovation is required to harness this resource for the benefit of network operation.

Active Network Management for distributed generation connections has been deployed successfully by numerous DNOs and many have developed BAU processes and commercial templates. New commercial models for ANM connections have been tested and demonstrated to have advantages over the incumbent Last in First Out model under certain circumstances.

A suite of voltage control equipment and solutions have been tested generating learning that provides a foundation for further DNO development of more active voltage control strategies. Clear value has been demonstrated in upgrading AVC functionality at primary substations (new relays and remote configuration), both to offer immediate benefit via voltage reduction and to enable future coordinated control.

Interconnection at 33kV, 11kV and LV has been demonstrated with strong evidence generated against 33kV interconnection and indications of potential benefit at 11kV and, to a lesser extent, LV.

A number of Real Time Thermal Rating solutions have been tested for a range of network assets and have generated evidence for wider deployment at higher voltages, particularly 132kV and 33kV OHL. The data gathering and analysis work of these projects has highlighted an opportunity to unlock network capacity using improved static ratings as a prior step to deployment of full Real Time Thermal Rating solutions.

Very large quantities of network monitoring have taken place across the lower voltage networks. Understanding of the 'why, what and how' of network monitoring has progressed and several DNOs have published monitoring strategies and best practice guides. If accumulated and made publicly available, an invaluable collection of data-sets could be established to support and enhance future R&D activities.

This review has not been concerned with whether the particular regulatory mechanism put in place for the support of innovation has been necessary or appropriate but rather with a consolidation of the learning that has been achieved with respect to the innovations that have been investigated. However, the volume of research, development and demonstration (R,D&D) activity led by the DNOs under LCNF and the relative lack of it in the years after liberalisation of the electricity supply industry in Britain and before the introduction of LCNF and its prdecessor, the Innovation Funding Incentive (IFI), suggest that, without these schemes, established 'business as usual' would have remained unchallenged and the necessary DNO R,D&D to facilitate the Low Carbon Transition is, in our view, likely to have been stagnant at best and non-existent at worst.

A key requirement set by Ofgem for the use of LCNF money was that learning should be shared. In reviewing the reports produced by the LCNF projects we have found variation in the quality of evidence reported. There are numerous potential reasons for this; however, in general, we observe a focus on 'successful

demonstration', i.e. that a project has demonstrated all the elements that were promised. This is in contrast to a focus on whether a project has generated robust evidence that the innovations have been, can be or should be moved up the scale of TRLs (or, conversely, should be pursued no further). Although mostly positioned as upper TRL demonstrator projects, Tier 2 projects often contained significant amounts of development work. We observe an absence of clear definitions for the TRL of each innovation trialled within a Tier 2 project and the absence of a learning and dissemination methodology that accounts for the range of TRLs, and crucially, allows for learning by failure. Our assessment of evidence for or against BAU adoption has not been conducted as a judgement of project success; however, it has been influenced by the way learning has been reported. If a project has not produced evidence of sufficient quality and it is difficult to determine a clear movement on the TRL scale, then evidence on BAU adoption remains highly uncertain. This is a very different end result from where a project has produced good quality learning that still leaves significant uncertainty and need for further work before the innovation can be regarded as a viable BAU option with a TRL of 9.

Notwithstanding the above comments on reporting, our conclusion is that much useful knowledge has been generated by the projects supported by the LCNF. In those terms, the LCNF has been valuable. Compared with the situation before IFI and LCNF, the DNOs are considerably more active in R,D&D and open to innovation. Moreover, we are confident that, collectively, they will now be much better at scoping, managing and reporting R,D&D than they were. In addition, the communities from which the DNOs' project partners have been drawn should now be much better equipped to support them. Both the increased level of engagement with R,D&D and improvements in the way the DNOs do it could be regarded as indicative of LCNF being a successful scheme.

A challenge arising from the quantity of learning generated is its accessibility within the originating DNO, and to other DNOs and the wider community. Successful dissemination and consolidation of the learning is essential to advance viable solutions and undertake further work in the most efficient manner. This review and synthesis work accomplishes the first stage of this process. For full value to be taken from the LCNF projects, it is essential that work to consolidate, contrast and compare themed learning across projects is undertaken in order to fully establish what gaps remain in knowledge and to inform further innovation work. We have identified a range of opportunities for such work in the recommendations of Section 10 of this report.

We believe that it is essential that DNOs continue to consider and evaluate novel technologies and methods that can be applied in planning or operation of their networks and benefit network users and now build on the LCNF learning to develop innovation strategies that are based on a coherent vision of future distribution system operation.

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14 Appendix A – Project Summary Tables

14.1 Visibility

14.1.1 Load Profiling

Title	DNO	Load Type	Method
Customer Led Network Revolution	NPG	premises	Statistical analysis of smart meter data from ~9000 British Gas customers.
Low Carbon London	UKPN	premises	Statistical analysis of smart meter data from ~5000 EDF smart meter customers.
LV Network Templates	WPD	distribution substation	Statistical analysis of data monitored from 800 distribution substations
Ashton Hayes Smart Village	SPEN	distribution substation	Monitoring of 4 distribution substations supplying the village
PV Impact on surburban networks	WPD	distribution substation	Substation monitoring was installed on seven LV feeders and one substation transformer
Hook Norton Low Carbon Community Smart Grid	WPD	distribution substation	Monitoring of 11 distribution substations with 46 load monitoring nodes installed in customer premises
Low Voltage Network Solutions	ENWL	distribution substation	Monitoring of 200 distribution substations
Flexible Networks for a Low Carbon Future	SPEN	distribution substation	Monitoring of 8 primary substations and 184 secondary substations
FALCON	WPD	distribution substation	Monitoring of 158 distribution substations
SoLa BRISTOL	WPD	distribution substation	Monitoring of 11 substations with connected SoLa customers
New Thames Valley Vision	SSEPD	premises and distribution substation	250 end point monitors and 100 distribution substation monitors installed.

Table 34: Projects related to Load Profiling

14.1.2 LCT

Title	DNO	Method
Demonstrating the benefits of monitoring LV network with embedded PV panels and EV charging point	SSEPD	Monitoring a development of ten low carbon homes near Slough
Customer Led Network Revolution	NPG	Monitoring of domestic customers - approximately (90 HP, 11 CHP, 133 EV, 300 PV).
Low Carbon London	UKPN	Monitoring of domestic customers - approximately (21 HP, 72 EV).
LV Network Templates	WPD	Monitoring of 120 PV FiT customers complemented by dataset for addition ~500 customers (all in WPD area)
PV Impact on surburban networks	WPD	Monitoring of seven LV feeders and one substation transformer in an urban area with dense PV penetration
Low Voltage Network Solutions	ENWL	Using validated detailed LV network models to simulate 'what-if LCT scenarios' using available external data sets
Early learning of LV network impacts from estate PV cluster	WPD	Monitoring of a new housing estate planned with full PV penetration
Validation of Photovoltaic (PV) connection assessment tool	UKPN	Monitoring of 20 distribution substations and 10 customers' PV installations.

Table 35: Projects related to LCT load

14.1.3 Comms and Sensors

Title	DNO	Comms	Sensors/Meters	sampling
Implementation of Real-Time Thermal Ratings	SPEN	Existing fixed line augmented by IPSEC VPN over 3G and GPRS	Nortech - Envoy RTUs and iHost. Skye Instruments (Weather data)	not found
Demonstrating the benefits of monitoring LV network	SSEPD	GSM/GPRS and DNP3	CURRENT group, Grid-Key and GE Energy products tested for voltage and current monitoring.	5-minute
Distribution Network Visibility	UKPN	M2M GSM	Powersense optical current sensors trialled along with existing standard sensors.	10 and 30 minute
Low Carbon London	UKPN	GSM	As per DNV project with additional voltage measurement at remote end of LV feeders within EIZs	10-minute
LV Network Templates	WPD	Radio Mesh, GPRS and PLC	Substation: GE KV2C. Moriarty CTs Feeder-End and PV: EDMI Mk7c	10-minute
Network Management on the Isles of Scilly	WPD	GE SD4 and EnraNET radio point to point. PPC Aranuka BPL	GE SM300 and KV2C CTs requiring outage	10-minute
Ashton Hayes Smart Village	SPEN	GSM modem	eMS sub.net IMVC-LV input modules and 3 phase Rogowski coils	10- minute
PV Impact on surburban networks	WPD	GPRS	eMS subNet and EDMI Mk6E meters. Voltage: Schneider voltage handle EE:200 and Nylon G Clamp CTs: US1000A:1A, Fluke i800 Current Clamp, Rogowski Coils,	10-60 minute
Hook Norton Low Carbon Community Smart Grid	WPD	UHF Radio point to point backhaul from substatin. PLC from customer premises to substation.	Schneider PM9 meters, Rogowski Coils	15- minute
Low Voltage Network Solutions	ENWL	GPRS	Nortech Envoy and GridKey MCU solutions (Rogowski coils)	10- minute
LV Current Sensor Technology Evaluation	WPD	GPRS	GMC i-Prosys, Sentec/Selex (Gridkey) , Current, PowerSense, Ambient, Haysys, Locamation	not found
Flexible Networks for a Low Carbon Future	SPEN	GPRS	Selex(GridKey), eMS subNet. Lyandis & Gyr in customer premises. Rogowski Coils NorTech iHost data acq	1- 10 minute
FALCON	WPD	WIMAX (Cisco and Airspan)	Cables: P341 relays, Tollgrade Lighthouse MV OHL sensors, Alstom P141 relays. Secondary Subs: Gridkey,eMS Sub.net	not found
BRISTOL	WPD	GPRS, PLC or mesh radio	In home measurement and control system (zigbee). Bespoke kit by Siemens and Moixa. Siemens substation metering Simeas P	not found
New Thames Valley Vision	SSEPD	GPRS for end-point M2M GPRS/UMTS for subs	end point: GE EDMI Mk7c substation: GE DGCM Field RTU Rogowski Coils	30min
Validation of Photovoltaic (PV) connection assessment tool	UKPN	not found	Current/Ormazabal	not found
Low Voltage Integrated Automation	ENWL	GPRS	GridKey Selex (uses LV Net solutions kit)	1-min
LV Protection And Communications (LV PAC)	ENWL	Within substation: proprietary protocol over radio. Backhaul: GPRS	not found	not found
ETA (Smart Street)	ENWL	Zigbee/GPRS/3G	Kelvatek switching devices monitor a range of parameters and communicate back to NMS	not found

Table 36: Projects related to Comms and Sensors

Monitoring Type	Device used and No. of units fitted	Quantities monitored	Sensors	Accuracy	Data Transmission	Data Communication	Comment
M1 Primary	7 SuperTapp N+ 5 Fundamentals DAM* MR Trafoguard	line voltage per phase Bi-directional RMS L2 current. Real Power and Reactive Power Tap position Temperature	Current – CTs EN60044-1 class 0.5S 1600/5, 1200/5 800/5 400/5 & 300/5 Interposing clip on CT on outgoing feeders 300/5 or 400/5 CTs Thermocouple	Voltage: to IEC 62053, Class 0.5 S Current to Class 0.5S Thermocouples: ±0.25%	15 second intervals with dead band of greater than 100v^	Fixed line firewall secured broadband ADSL Existing DNO SCADA	Values extracted from AVC relay Alarms fed over SCADA link
M2 HV feeder monitoring	1 Nortech Envoy	Bi-directional RMS L2 current. Real Power and Reactive Power	Interposing clip on CT	Current to Class 0.5S	1 minute averaged over 15 second intervals	Roaming GPRS to iHost server	
M3 HV Industrial and Commercial	1 Direct metered 5 Commercial aggregator sites	Real Power	Commercial Metering Modbus Load feed	Voltage: to IEC 62053, Class 0.5 S Current to Class 0.5S	30 minute averaged over 1 minute intervals 1 minute averaged Modbus data link for loading information	SCADA BMS or GPRS	results obtained from commercial metering in place with energy supplier and commercial aggregator
M4 Secondary Distribution transformer monitoring	3 Tapconn 230 20 Nortech Envoy 2 Kelvatek gateway	RMS phase voltage and line to neutral voltage per phase Bi-directional RMS currents per phase and neutral current. Real Power and Reactive Power Phase angle per phase Tap position 1st to 50th Harmionic Flicker Temperature	Fused voltage take off, Rogowski coils PQube power quality meter ND metering solution rail 350 Novus Digirail Temperature sensors	Voltage: to IEC 62053, Class 0.5 S Current to Class 0.5S Thermocouples: ±0.25%	15 second intervals with dead band of greater than 1v^ 1 minute averaged over 15 second intervals	Fixed line firewall secured broadband ADSL Roaming GPRS to iHost server Roaming GPRS to iHost server	Values extracted from AVC relay
M5 LV Feeder monitoring	3 Nortech Envoy 32 Prysmian smart link box	RMS Phase voltage and line to neutral voltage per phase Bi-directional RMS currents per phase and neutral current. Power factor per phase Phase angle per phase 1st to 50th Harmionic Flicker	Fused voltage take off Rogowski coils Conventional VT / CT in link box Kelvatek Bidoing	Voltage: to IEC 62053, Class 0.5 S Current to Class 0.5S	1 minute averaged over 15 second intervals		

Table 37: CLNR Monitoring Equipment – reproduced from [108]

14.2 Storage

Title	DNO	Capacity	Voltage Level	Battery	Efficiency
Demonstrating the benefits of short-term discharge energy storage on an 11kV distribution network	UKPN	200kWh 600 kW max 15 mins +-600kVar	11kV	Li-ion	Varies with power exchange magnitude. Battery: 90-95% Full round trip: 78-84% Auxillary power requirements significant in round trip figure
1MW Battery, Shetland	SSE	3MWh 1MW	11kV	VRLA	Battery: 85% Full round trip: 75%
Customer Led Network Revolution	NPG	2,500kVA 5,000kWh	11kV	Li-ion	Round Trip Efficiency (excluding parasitic losses) 83.2% Average Parasitic Load 29.5 kW Round Trip Efficiency including parasitic losses, assuming one charge/discharge cycle per day 69.0%
		100kVA 200kWh	0.4kV	Li-ion	Round Trip Efficiency (excluding parasitic losses) 86.4 % Average Parasitic Load 2.50 kW Round Trip Efficiency including parasitic losses, assuming one charge/discharge cycle per day 56.3%
		50kVA 100kWh	0.4kV	Li-ion	Round Trip Efficiency (excluding parasitic losses) 83.6 % Average Parasitic Load 1.77 kW Round Trip Efficiency including parasitic losses, assuming one charge/discharge cycle per day 41.2%
FALCON	WPD	50kW/100kWh	0.4kV	sodium-nickel	Battery: 98%
BRISTOL	WPD	4.8kWh for domestic sites and 22.5 kWh for commercial sites	0.4kv	VRLA	not found
New Thames Valley Vision	SSEPD	36 kVA 37.5kWh	0.4kV	Li-ion	not reported
LV Network Connected Energy Storage	SSE	3 single phase 25 kW / 25 kWh	0.4kV	Li-ion	static schedules : 80-88% dynamic operation: 68% - 72%
Trial of Orkney Energy Storage Park	SSE	500kWh 2MW	33kV ?	Li-ion	not reported
Smarter Network Storage	UKPN	6MW/10MWh	11kV	Li-ion	not reported

Table 38: LCNF Battery Projects

14.3 Flexible Demand

	CLNR	LCL	Falcon	NTVV	C2C
Method	I&C contracts for load reduction or generator substitution	I&C contracts for load reduction or generator substitution	I&C contracts for load reduction or generator substitution	Automated ADR where the Honeywell system interacts with customer building management systems that are able to control plant such as air-con and refrigeration.	I&C DSR contracts for both new and existing customers for a managed connection within new network operation arrangements
Use-case	Post fault constraint management. Primary substation upgrade deferral.	Constraint management - Pre-Fault, Post_Fault. Outage Management. Primary substation upgrade deferral.	Pre fault constraint management. Primary substation upgrade deferral.	Peak Reduction	Primary substation upgrade deferral. Increased connection capacity.
Trial Scope	25 Weeks, 14 customers, 33 events.	3 months summer with 26 customers, 3 months winter with 19 customers. 37 customers total - 21 load, 19 generation. 185 DSR events.		30 ADR contracts signed directly with customers. Phase1 Apr 14 to Apr 15. 250 load shed events.	10 new and 10 existing load customers. 20 fault occurences
Dispatch Method	ANM system signals to Aggregators via SMS or Modbus	phone-call and ANM system triggers	phone-call	Automated system - DNO control via Honeywell Building Management Systems	Automated system -managed connections
Response Time	30 mins max	30 mins max	30 mins max	Not Found	Protection time-scales
Response Duration	2-4 hours	1-3 hours	1-2 hours	0.5 - 2 hours	
Technical Reliability	Load Availability/Utilisation = 100%/100% Generation Availability/Utilisation=83%/91% Combined Reliabilty = 83% Results for 8 sites (2 load, 6 generation)	Load Availability/Utilisation = 48%/95% Generation Availability/Utilisation=30%/95%	In progress	Full analysis not yet published, interim info released suggests around 73% reliability and between 8.9% and 11.3% average load reduction.	
Contractual Arrangements	Availability/Utilisation = £10/MW/h and £300/MW/h or Daily Charge = £306/MW/day	Availability/Utilisation = £50-100/MW/h and £200/MW/h	phase 1: £300/MW/h phase 2: £600/MW/h	Voluntary customer sign up based on cost saving proposition	New customers - managed connection offer. For existing customers - aggregator commission model with a mid-point target of £20k/MVA pa.

Table 39: I&C DSR Comparison

14.4 Ratings

DNO	Project	Asset	Voltage	Average Improvement
SPEN	Implementation of RTTR	OHL	132kV	1.27 - 2.19 %
	Flexible Networks	OHL	33kV	11%
		Primary Transformers	33kV	10%
NPG	CLNR	OHL	33kV	
		OHL	11kV	
		Underground cable	33kV	
		Underground cable	11kV	
		Primary Transformers	33kV	
		Secondary Transformers	11kV	
WPD	Low Carbon Hub	OHL	33kV	13%
	FALCON	Underground cable	33kV	7%
		Underground cable	11kV	7%
		Primary Transformers	33kV	10%
		Secondary Transformers	11kV	10%
		OHL	11kV	
UKPN	Flexible Plug and Play	OHL	33kV	14%

Table 40: RTTR Comparison