Project FALCON
Commercial Trials Final Report

September2015

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FALCON

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SECTION 1

Executive Summary

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1.1 FALCON Commercial Trials – report purpose

The commercial trials that were undertaken within Project FALCON as a discrete requirement that was part of a far wider scope that ultimately culminates in the creation of new software based network planning tools. As part of the overall scope WPD required to design, build and operate a new commercial demand response programme that could potentially be used by DNOs as an economic alternative to conventional reinforcement or a range of other smart technologies that could be used to manage constraints and provide additional network capacity.

The following report details each stage of the trials processes and presents the learning and conclusions that were derived from the work carried out. In addition it provides context in relation to the broader market for current and proposed DSR services which require to be taken into account when seeking to determine how DNO operated programmes are likely to be introduced as 'Business as Usual.'

1.2 Report Deliverables

The report provides a wide range of outputs relating to the full trials lifecycle from initial assessment and design through to their operation and analysis:

- High level programme design
- Assumptions and dependencies
- Technical design and development
- Commercial / financial design and development
- Participant and industry engagement
- Trials Operation over 2 seasons
- Analysis
- Trials modification based on captured learning
- Conclusions
- Knowledge capture and dissemination
- Results / Conclusion
- Next steps / impact on business as usual
- Market overview – synergies and conflicts

A variety of different methods have been used in order to develop the Commercial Trials programme which call upon experience from existing Demand Response services and other trials operated previously in relation to a DNO as the service operator. Where there are precedents that have been established from existing programmes or other innovation trials the report includes references to appropriate resources either contained with the document or external links to further resources.

An interim report was published in June 2014 after the first season of winter trials. Where appropriate the interim report content is included within this final report and is clearly labelled as to whether results refer to the first or second winter of operational trials. Following the interim findings several modifications were made to the second season of winter trials based on the learning gained to that point. The final report therefore seeks to apply the same methodology with regards to design, develop, build operate and analyse to provide a consistent approach and reporting over the whole project lifecycle.

1.3 Conclusions

The scope of the DSR trials being carried out within FALCON are far more commercially focussed than any previous investigations carried out by DNOs. This has been set against the context of establishing an industry roadmap as to how this could potentially be offered as a 'Business as Usual' solution.

FALCON can be deemed to have already achieved a very meaningful set of learning outcomes during the trials operation that have assisted WPD in increasing both its and the industry's understanding of how commercial techniques may be applied and how they may require to be adapted in order achieve desired efficacy levels. Building on the learning from the first season winter trials, we altered the scope of the second season trials to extend the learning and results beyond the original expectation of the project scope. Due to the effectiveness of the first winter of operation in determining key issues within the current market for DSR services we recognised that to repeat them again for the second year of operational trials would merely be validating several fundamental issues, when we could potentially attempt to address them through modification of the scope and methodology. The alterations should therefore enable WPD to minimise duplication of learning and continue to achieve fresh achievements beyond the originally proposed scope.

The main highlights of the first year's results and consequential conclusions were as follows:

- Reliability is critical to DNO deployment of commercial techniques. Under the conditions applied within the trial it is unlikely that a DNO could rely on such services as a viable alternative in order to substantially defer capital investment.
- The level of funding that a DNO is likely to have to make as operational payments to participants is in conflict with the principal of commercial techniques being a lower cost alternative.
- Existing DSR programmes and their associated contractual terms create restrictions that require to be addressed if participants are to benefit from multiple programmes. A cost sharing model will need to be developed to reduce cost of operation.
- Identification of potential participant sites in the correct location and their engagement is a critical aspect of developing a DSR service that can affect specific constraint points.

Initially, it is likely that there will only be very limited correlation between network issues and suitable customers to offer load reduction or generation.

- DSR service participants are heavily biased towards providing service via Technique 6 'Distributed Generation'
- A non-engineering approach to managing network issues and future design decisions is currently not well aligned with a DNO's existing resources. Major investments in several areas including culture, skills development, recruitment and IT systems will be necessary in order to establish DSR services within the existing BaU options.

The main highlights of the second season results, following the variations were as follows:

- Reliability statistics were vastly improved with the introduction of a longer notification period, extended from 30 mins to between 7 – 12 days. Although this does introduce another challenge of ensuring sufficient accuracy of forecasting exact time of need.
- The level of funding that a DNO is likely to have to make as operational payments to participants is in conflict with the principal of commercial techniques being a lower cost alternative for 11kV capital works.
- The general principals of a shared service model are supported by the operational results and give a positive indicator to continue work in this area to find agreeable commercial terms that encourage the development of DSR services on a non-exclusive basis within the market.
- When seeking to manage 11kV constraints, the identification of potential participant sites in the correct location and their engagement is a critical aspect of developing a DSR service that can affect specific constraint points.
- Despite increased efforts and significantly enhanced financial incentives, DSR service participants are heavily biased towards providing service via Technique 6 'Distributed Generation' rather than 'Load Reduction'
- DNOs are moving towards organisational change that will support the development of DSR services alongside more engineering based alternatives. This is largely through the recognition of some of the potential benefits that are being identified through innovation projects and industry working groups including Ofgem funded initiatives.

IMPORTANT NOTE:

In order to fully appreciate the report and its findings in relation to the commercial parameters outcomes it is necessary to have a minimum level of knowledge in relation to many of the complex sensitivities associated with the current and potential future of the DSM / DSR Marketplace. The report therefore includes and extensive summary of the existing and foreseeable services that are likely to be actors within the commercial and operational framework that will potentially influence the DNO use case for DSM / DSR. These resources are contained within the appendices section of the report and it is recommended that if the reader is unfamiliar with context these market conditions create it should be a prerequisite to read the appendices in advance of the FALCON Commercial Trials Final Report

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SECTION 2

FALCON Introduction

2.1 Power Transmission and Distribution

To date the principals that have determined electricity network design and its operation have been predicated on the assumption that generation is likely to be large centralised power stations. This in turn creates a single direction of flow to customers at the opposite end of the network. On this basis the network is assumed to maintain a passive role to accommodate the safe transfer of power from the top to the bottom, or left to right as shown on the diagram below.

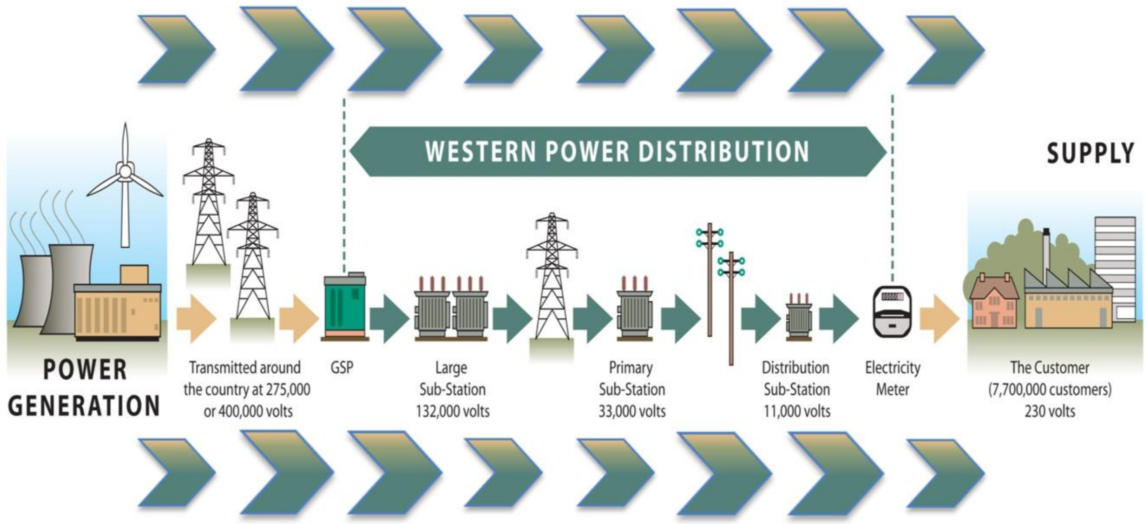

Figure 1 - Topology of GB electricity networks

The whole network requires to be designed and constructed with adequate capacity to meet the peak annual demands at every level. For the Distribution Networks which operate from voltages of up to 132kV down to final delivery at around 230 volts it can result in the network being oversized for 99%+ of the year but out with the design ratings for certain period on just a few days.

Traditionally, any such constraints would be addressed through network reinforcement, which will generally involve the re-specification of the assets that are determined to be limiting the capacity. This is often takes time and costs money that results in additional or larger capacity cables, transformers and switches to be installed along with their related ancillary equipment. In some cases this may mean that new street furniture, sub stations and pole mounted equipment is required to be installed.

2.2 Purpose of FALCON

FALCON (**F**lexible **A**pproaches for **L**ow **C**arbon **O**ptimised **N**etworks) is a project led by Western Power Distribution (WPD) involving a number of partners. The project is partially funded by the energy regulator, OFGEM, via their Low Carbon Networks Fund, which tasks Distribution Network Operators (DNOs), like WPD, to trial new ways to provide security of supply at value for money as Great Britain moves to a low carbon future.

The project is a £16.19m project and started 1st January 2012. It has five overlapping phases: mobilisation, solution design, solution build, trials implementation, consolidate and share. Project completion date is 30th September 2015.

The ultimate deliverable from FALCON is a new prototype software that assists network designers and planners to make choices relating to deploying new techniques and technology as an alternative to conventional reinforcement. The prototype simulation software, the Scenario Investment Model (SIM), has an embedded network modelling tool capable of analysing the network as loads change over time. This will allow expected constraints to be visualised for different time periods over many years. The SIM will simulate the application of the various techniques to solve network constraints so that many potential solutions are considered over a long time frame. It will then allow the user to select optimum solutions that are evaluated against various factors including cost, speed of implementation and impact on network performance and losses. This is particularly important in the development of a smarter more efficient system. When electricity is produced at a power station it needs to travel through the National Grid transmission system then on through the lower voltage distribution network to consumers. As the DNO for the Midlands, South West and Wales, it is WPD's responsibility to ensure that the installed infrastructure meets the needs of homes and businesses.

Conventional reinforcement methods for centralised networks mean that they have been designed and maintained to cope with times of peak consumption, which can commonly be just a few hours on the coldest winter or hottest summer days. This can lead to expense and disruption, as more cables and transformers are laid to create extra capacity that represents **less than 1%** of actual annual consumption. FALCON is testing smarter alternatives to reduce the need to do this.

FALCON will operate live system trials to test six alternatives to conventional network reinforcement methods, to assess their effectiveness, see how they work in practice, establish likely costs and generate new learning about how these can be rolled out across the networks in the future. An innovative new communications network will allow these to be controlled and all the resulting performance data captured to ensure that our energy models reflect real world performance.

Four of these options are based around engineering approaches that will involve modifications to the network itself:

- Dynamic Asset Ratings
- Meshed Networks
- Automatic Load Transfer
- Storage

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The remaining two options are Commercial Techniques, which focus on consumer behaviour. These will provide opportunities for participants in the trial to receive an incentive for changing their behaviour for a short period of time. This is commonly known as a Demand Side Response (DSR). The two approaches to achieving the desired behavioural change are by:

- Reducing load by stopping, or deferring consumption
- Starting or increasing generation reduce load and / or export to the 11kV network

2.3 Identifying between Season 1 and 2

As already indicated in the Executive Summary, the trials were initially intended to design and develop trials for commercial techniques that would be operated first during the winter period commencing November 2013. Following this it was the intent of the original plan to repeat the trials without significant alteration in the second winter trial in order to provide a broader set of results data. By doing so we would have the opportunity to carry out comparative analysis between the two periods and help validate much of the key learning. With DSR still being a relatively new technology and application of it across the industry in its infancy, the marketplace was undergoing parallel developments. This was to such an extent that the combination of changing market conditions along with results of the first season trials presented an opportunity to advance the scope for learning and evolve the programme design.

As a result of this the commercial trials underwent a significant redesign for the second season in order to address some of the issues we identified. The key changes were approved as it was highly unlikely that a DNO would adopt DSR in the season one format out with the trial conditions. Detailed explanations of both trials including the modifications for the second phase are contained within this report. For clarity of reporting the document has been set out in chronological order with conclusions for season 1 being mainly documented up to *section 12.4* and season 2 repeating the formatting of knowledge outputs in *sections 12.5 to 15*. Where appropriate the document will identify work carried out during each phase or comparative data by the following notation

(S1) Season **1** Nov’13 to Feb’14

(S2) Season **2** Nov’14 to Feb’15

2.4 Methodology

The methodology applied in the authoring of the report varies in relation to the stages of the trials development being described. In respect of much of the high level design principals, stakeholders were engaged and sensitivities identified on a consultative basis. The outputs are therefore a reflection of this process and the report seeks to offer a basis for the parameters considered and either justification or reason for any decisions that were made. To a large extent, this was determined by a small number of key factors:

- Budget should be based upon cost no greater than that of an 11kV substation upgrade.
- Both direct and third party engagement should be tested
- Reliability is paramount and performance monitoring is required to reflect this
- Commercial arrangements require to test enduring terms and not just for 'trials' period, therefore they require to be compatible with the broader market
- Service should be primarily focussed on 'pre-fault' conditions for enhanced efficiency and cost reduction objectives
- Trial participants are limited to Half Hourly metered, non-domestic properties

As a result, much of the report will be provided in the form of statements, with references to supporting resources that seek to verify the assertions offered.

The 'trials operation' stage offers a great deal of measurable data relating to participant performance against clearly determined objectives, as well as the attitudinal research that was carried out before, during and after. The methodology during this phase is therefore significantly different and the analysis in this area is a combination of statistical and socio-technical reporting.

Overall the report seeks to, not only determine the most critical factors to the operator of a DNO, but also understand how those align to broader marketplace and any potential participants in commercial intervention techniques in the future.

The success criteria for the commercial trial is not predetermined as to be the creation of a new DSR (Demand Side Response) service capability to be introduced. The purpose of the trial is primarily to establish if and how a DSR service may integrate amongst conventional reinforcement and other alternative 'smart' techniques. This means that even if the trials were to result in new learning that strongly supported the assertion that commercial techniques were **not** well suited to DNO needs, we could regard this as success in the context of the trial as long as there is data to support that outcome.

2.5 High Level Learning objectives

Due to the similarity of the impact of the two commercial techniques on the programme operator it can often be assumed that their similarities extend right across the board. Despite this, FALCON has separated demand reduction and generation within the learning and reporting processes in a clear attempt to challenge such assumptions and determine what the potential differences are potentially how this may alter the design and development of future DSR programmes.

2.5.1 Technique 5 Description – *Load Reduction (LR)*

It is important to note in both this section and that of 2.5.2 that these should be considered in the context of Section 19 'Appendices' which set out the functions of DSR within the broader UK Marketplace.

Load Reduction in this context, refers to a change in behaviour by a customer site in response to an explicit signal triggering a pre agreed action. The action being referred to should be the interruption of a participant's internal electricity consuming processes, either as overall avoidance or, more likely, to defer these to a later time. Typically, this is expected only to yield results from 'non-disruptive' intervention which generally relates to processes that have some latent capacity within them. These often include heating, cooling and pumping as it is generally the case that there is a delay between the commencement of the interruption and any discernible effect within the participant's property. In the majority of cases it is expected that this will generally take the form of a deferment and will require to still consume a similar total volume, just shifting this to a later period. Conversely, processes such as lighting or industrial processing will generally have a very direct and overt impact, but if the 'real cost' of the interruption is lower than that of the 'service payment,' it may still be considered to be viable.

2.5.2 Technique 6 Description – *Distributed Generation (DG)*

Distributed Generation is commonly expected to be stand-by generation which for the majority of its operational life will be idle, with a sole purpose of providing electrical cover for critical supplies in the event of a failure in the primary supply from the 11kV network. While assets of this type do represent a significant proportion of generation within DSR programmes, there are other classifications including combined heat and power installations. Where combined heat and power is encountered, it will often be the case that it is the primary supply, but it either has headroom or, through 'load reduction' it will result in the decrease of demand or increased export.

On receipt of an explicit signal, Distributed Generation sites will carry out a pre agreed action with their embedded generation asset(s). Where the generation is off, it will typically be started and, if already running, it will increase the power output to demand ratio.

There are various dependencies relating to such operation, in relation to safe operation within any related constraints such as synchronisation with the mains network and authorised connection permissions. An explanation of these and related considerations are detailed in section 5 - Process Development.

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2.5.3 Learning Topics and Outcomes

A full record of the learning topics, outcomes and results will be available through the Knowledge Management resources associated with Project FALCON. The full range of learning objectives go into finer levels of detail, including aspects of internal processes which are determined to be of limited value within the context of this report. The more relevant of these to the broader leaning outcomes are provided in sections 12.11– Key Learnings. Learning topics are made up of several learning outcomes which will be a combination of planned (those we set out to learn) and those we have collected on the way.

During the design and build phase and ongoing throughout the first set of trials, we identified over 30 more key learning outcomes at a higher level. Each of these has been documented and recorded in line with the agreed knowledge capture approach and have been combined with the planned learning outcomes.

Captured learning outcomes will continue to grow and revise as the Project moves forward and revisions occur. Each lower level detail document does carry a version control, so we can retain what we found originally, why we changed something and what the outcome was.

For the commercial trials specifically, as we are carrying out two sets of independent trials, we will be revisiting many of the documents at the next stage of re-design (or refining) and trial as they develop.

The table below shows the topics we have chosen as key learning topics – parent, for the Commercial Techniques for the duration of Project FALCON:

Learning Topic – Parent	**No. Learning outcomes**
Develop a dispatch management system for commercial demand side response	18-20
Targeting, recruiting and signing customers for a DSR scheme through all channels	15
Identifying the most suitable use, and time for deploying DG in a DSR commercial environment noting any limitations	5
Monitoring, controlling and responding to events on the customer side and control room side of a commercial DR scheme	4
Making a comparison to when the service is used direct, or via suppliers and addressing the challenges	5
Analysing performance and outputs of commercial trials in a DNO environment and drawing conclusions	10
Creating an automated data, billing and customer communications system for managing a commercial platform	5
The customer journey and modelling a DSR commercial scheme	6

Table 1: Learning Topics

For further resources relating to Knowledge Capture and Dissemination you can follow the attached link.

http://www.westernpowerinnovation.co.uk/Document-library/2015/Project-FALCON-KCD.aspx

SECTION 3

DSR (Demand Side Response) introduction

It is important in establishing the context of the commercial techniques scope within the overall FALCON trials to take a step back and clarify what the definition of the term DSR represents within the UK Electricity Industry.

Ofgem have previously published a consultation entitled 'Creating the right environment for demand-side response' (June 2013) in which the following definition was offered.

What is demand-side response?

For the purposes of this document, we define demand-side response as actions by customers to change the amount of electricity they take off the grid at particular times in response to a signal. As such, we refer specifically to 'transactable' demand-side response, where a customer chooses to change the way they consume energy. This could include choosing to change their behaviour and habits to alter their energy consumption, or choosing to let somebody else help them manage or control their energy consumption. These examples differ from ('non- transactable') system management activities that cause no discernible change in the quality of electricity supply and in which a customer has played no part. Transactable demand-side response differs from interruptions to customers' electricity supply that they have not chosen to incur such as rolling reductions or 'blackouts' that are often implemented around the world when energy shortages become critical.

In this context DSR excludes mechanisms such as time of use tariffs or other set incentives that encourage a more permanent behavioural change that requires no dynamic signal or active response.

Furthermore the Introduction section of the consultation document provided the following justification for the regulator's interest in gaining a greater understanding of the current environment for DSR provision.

Why is demand-side response important?

Customers have always had the potential to shift their demand. Now this potential is increasing for a number of reasons, as set out below. As it does so, new potential competitive opportunities materialise, offering an avenue for innovation and new products.

- **The electricity system is being upgraded**. Ofgem has estimated that due to plant closures and the need to replace and upgrade the UK's electricity infrastructure, over the next decade the UK electricity sector could need around £110 billion of capital investment. Demand-side response provides one way to reduce or delay some of these investment costs, which will ultimately be passed through to customers' bills. Furthermore, demand-side response may be a valuable tool, alongside others, for managing the increasing contribution that intermittent generation is expected to make to the generation mix.
- **We are changing the way we use electricity.** As more heating and transport is electrified over time, overall electricity consumption is expected to rise, as well as consumption at peak times. The technologies behind this electrification, such as heat pumps and electric vehicles, could make it easier for customers to be more flexible about how and when they consume electricity.

- **Smart meters will open up opportunities.** Larger non-domestic customers already have advanced metering, which can help to lower the cost of monitoring and verifying demand-side response. The Government's ambition is for all households and other small energy customers to have smart meters installed by their energy suppliers by 2019. Smart meters will provide new opportunities for domestic customers to improve their understanding of their energy consumption, by giving them better information about their consumption, in a more accessible form. Half-hourly consumption data from smart metering could make contracting for demand-side response easier by providing a means to verify changes in consumption. Furthermore, a combination of two-way communication and potential load-switching functionality provided by smart metering could provide opportunities for customers to negotiate new types of contract, for example to limit their load in some way.

In addition to the introduction section of the Ofgem consultation we would also highlight that the changes to generation are just as significant as those relating to how we consume. As the volume of electricity generating capacity shifts from large scale, centralised, thermal plant connected at high voltage to distributed infrastructure the operational challenges differ. With centralised generation the network required to provide a conduit that was capable of carrying power largely in one direction, but with adequate capacity to meet the demand on the worst days of winter. The power stations enabled the system to be controlled relatively easily as the majority could be modulated as required through a small number of instructions. Now that we have distributed generation of which the majority is made up of renewable sources delivering variable capacity dependent on the weather the challenges have become greater and more numerous.

Full details of the consultation and published responses can be accessed at

https://www.ofgem.gov.uk/publications-and-updates/creating-right-environment-demand-side-response

Please note, as part of the FALCON Project design, we limited the scope of the Commercial Technique trials to non-domestic properties with Half Hourly metered supplies.

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SECTION 4

FALCON DSR design approach

There are already a number of operational DSR schemes within the UK that are not run by Distribution Networks. They help manage conditions such as system balancing and help participants avoid peak costs such as annual transmission charges. More information on these can be gained in the appendices section of the report.

In considering how the FALCON commercial trials would be designed it was necessary to be aware of how pre-existing DSR services operate but not to adopt their design as the purposes for which they are used is very different to the geographically sensitive constraints that are the primary purpose of DNOs. As a result the commercial trials did not attempt to copy or adapt the design of any other DSR programme and a fresh approach was adopted, where we were able to define an appropriate use case that offered the best possible likelihood of success, particularly as it was to be measured against several other alternative methods.

With several other existing and even more potential future user of DSR services across the industry, an important starting point was to understand how and why other programme operators wish to use this approach. Furthermore, it was necessary to detail where there may be conflicts or synergies between programmes to ensure that the design that would be proposed within FALCON would be workable as an enduring arrangement and not over simplified simply for the trials.

4.1 DSR – Market / Programme conflicts

An important learning outcome achieved during the Seasonal Generation Deployment project carried out previously by WPD was that outside of the trials environment, there are conflicts with participants' other priorities including participation in other DSR schemes.

A great deal of work has been commenced into looking at the flexibility of different load types and identify where latency can be leveraged as flexibility to be sold as DSR. As well as with generators having to consider the core purpose of their asset, particularly in the case of standby power, research has determined positive correlations between reliability and regular use of the asset. This is generally down to a number of factors that relate to having a comprehensive testing regime for intermittently used generation. As with the average diesel car, it is more likely to be in a 'ready' state if regularly used and serviced, than if left for prolonged periods of inactivity. With generators there are a number of aspects that can be argued to reflect a good quality test regime. Regular running 'on load' simulates actual usage and test all critical components, such as:

- Battery charge for engine start health;
- Engine and switchgear settings;
- Mechanical components;
- Fuel delivery and quality. (supports manufacturers' recommended fuel management strategy); and

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- Identify any faults during ‘non-critical’ operation.

Despite the largely technical benefits of regular usage in conjunction with commercial opportunities, there has been little analysis into conflicts between different DSR/DSM programmes and their operational benefits, cost savings and revenue. Below are the typical programme operator requirement ‘use cases’ and aspects that could be determined to act as barriers to BaU (Business as Usual) operations.

FALCON is not the only, or even first LCNF trial to include DSR as a key aspect of their trials in attempt to establish whether it is functional enough to be considered a viable alternative to conventional or new engineering methods of network operation. Much of the learning achieved from these to date has been included within the FALCON commercial trials to avoid unnecessary duplication of basic testing and establish the more advanced challenges including comparative analysis of reliability and commercial impact in a BaU environment.

Details of the preceding trials that have been carried out with LCNF funding are included within the appendix section of the report.

4.1.1 The SO – (System Operator)

As outlined within section 19, there are several programmes operated by National Grid in its joint capacity as System and Transmission operator. For demand side participants, the SO service is most commonly the ‘Balancing or Reserve Service’ STOR, but an increasing number of sites either offer, or are considering the potential of Frequency and Footroom services as aggregators develop offerings to harness the potential of multiple smaller sites. It should also be noted that while National Grid currently only procure a very moderate proportion of their balancing capacity from demand side providers, they have publically stated their intent to grow this to a minimum of 50% by 2030.

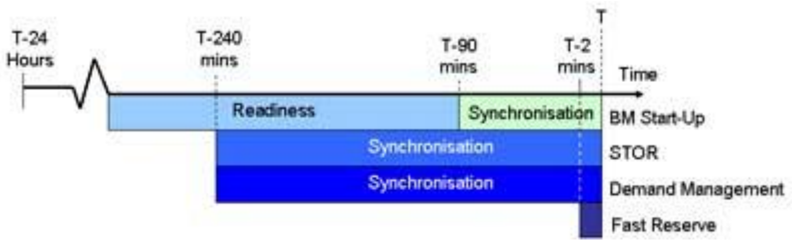

Figure 2 - System Balancing timeline

The diagram above which was sourced from the National Grid, ‘reserve services’ page (http://www2.nationalgrid.com/uk/services/balancing-services/reserve-services/) and shows how the range of services are used in relation to ‘real-time’ as represented by the letter ‘T’. Demand side providers do not currently offer either BM Start-Up or Fast Reserve. For responses quicker than those offered by ‘Reserve services’, Frequency services are contracted by National Grid which can either be dynamic and constantly changing to reflect National System Frequency or triggered by at a specific set point with response times as rapid as less than 1 second.

The SO services of these types are on the most part contracted and dispatched on a non-geographic basis, but due to the criticality of the services, they are typically 'exclusive' and cannot be operated in conjunction with any other commercial programmes. A premium is paid for capacity by the SO in the form of an 'availability' payment and where appropriate a further 'utilisation' payment for volume delivered when called upon. Most significantly, the exclusive nature of the contracts means that if being paid availability payments for STOR, a site should not operate any other ancillary services or cost avoidance schemes that require the same capacity capability. This currently prevents multi-functionality from even multiple SO programmes simultaneously before even considering how this could be achieved by other markets such as Distribution Networks. It is however feasible that a site that can meet the technical requirements for Frequency Services can declare itself available for the faster response service during any periods where STOR availability hasn't been committed.

The SO does contract STOR services under two different contractual conditions, known as committed and flexible. As the name suggests, the flexible service conditions to allow for a limited amount of adjustability around availability, but under normal circumstances will still require to declare exclusivity for STOR provision on a week ahead basis. Such firm contractual conditions results in reserve services generally being in conflict with any other commercially driven operation during STOR availability windows.

In addition to the services listed above, National Grid has commenced auctions and contracting for further DSR through a new mechanism called 'Capacity Markets'. As this is not impacting the current DSR market until it goes operationally live. Further details on Capacity Market can be referenced inn Section 19.5.2

4.1.2 The TNO - (Transmission Network Operator)

National Grid also has the responsibility for Transmission Network Operation. Within the TNO's charging methodology for TNUoS (Transmission Network Use of System), it is possible to change consumption and/or generation behaviour to avoid annual costs for electricity transit through the transmission network. The commercial principles of this methodology are highlighted in section 19.4.1.

Triad avoidance is normally operated around one of two methods, Triad Management or Triad Warnings. Depending on which mechanism is used, the methods can be considered as DSR or DSM. This highlights an interesting anomaly within the overall service.

Most electricity suppliers can offer triad warnings to their clients which range in timing and frequency, from weekly through to daily, typically being issued either day ahead or in the morning for that specific day. There are also a small number of specialist energy management consultants who can offer a daily service based on either a success fee or annual subscription charge. These will typically be of greater accuracy as they will base their

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analysis on consideration of several supplier alerts, as well as their own internal working. When operating with warnings, a site is generally making the decision to operate in advance of real-time by enough time that it is more likely to be considered as DSM.

Reliability of 'warning services' for each source can partially be assessed by looking at their historical attainment for hitting all three triads, but also critically it is necessary to consider the number of warnings that they issued in order to achieve their performance record.

This, however, is only part of the picture as, due to changes in the way the overall energy market operates and responds to triad alerts, the changes can, and will, affect the reliability of warnings. There are three main factors that affect reliability and both are related to activity that takes place at the distributed level of the network:

1. With an increasing volume of participation in triad avoidance, the warnings offered by the large suppliers have a direct impact on the likelihood of a triad being realised. Using the same principal as the combined impact of many consumers reducing their consumption, the increasing volume of participation will flatten many of the peaks. This results in increased numbers of calls requiring to be issued;
2. As the winter period experiences a flattening of many of the peaks, it is also increasingly likely that the failure of any of the big suppliers to issue a warning will, as has historically been demonstrated, create enough of a peak to make that day one of the three triads. The consumers who subscribe exclusively to that particular suppliers Triad warnings will therefore also fail to hit all three triads.
3. Increasing levels of distributed generation is connecting to the system at a Distribution level and is therefore not subject to TNUoS calculation. The most significant element of this is the rapid growth in renewables, in particular. If the wind output is either lower or higher than predicted it will have a direct impact on either increasing or reducing the volumes supplied through the transmission network. It is widely recognised that wind prediction is notoriously difficult and assessing how much may be delivered around a suspected triad peak, either several hours or days in advance, is a significant variable to consider amongst the other influences currently considered.

Triad Management is provided by aggregators by virtue of their technical infrastructure they have developed in order to meet response times and metering conditions set out by other schemes such as services from the SO. Due to their technical infrastructure, aggregators often have the capability to communicate directly on a machine to machine basis with assets on participating sites to either start / increase generation or reduce demand. This creates an advantage of not having to make a decision until closer to the time when a triad may or may not occur. During this time, aggregators may have the benefit of having received and assessed the impact of all the large supplier triad warnings in addition to those of any other subscriber services. They also have access to, and can monitor, the national system demand profiles that show consumption levels and generation outputs. These are updated on a 30 minute basis.

Armed with this more accurate information and the ability to remotely start / stop generation and reduce demand, aggregators can more prudently respond to ensure that all triads are avoided but have a risk profile that will avoid excessive number of calls and shorter runs, and thus reduce the costs associated with the operation. When operated in this dynamic manner, where notice periods are significantly shorter and potentially full responsibility for running reassigned to a third party, the operation of the service can be classified as DSR.

As avoidance simply requires a site to maximise their load reduction and increase generation in order to benefit, there can sometimes be correlation with other schemes which have a high propensity to be used during periods of high demand. This can sometimes result in the SO, TNO, supplier and DNO issuing a dispatch call during periods that eventually become classified as one of the three 'triad' periods, resulting in multiple benefits. This is, however, only a loose correlation and, if contracting to one of the other services, may force a site to reject triad warnings in favour of a previously contracted position. As triads are so lucrative it is common for sites to opt out of other programmes during afternoon / evenings of the winter period (November to February) to enable triad as the prime mover in DSM/DSR decisions.

4.1.3 Energy Suppliers

It is still not yet clear as to what form the Energy Suppliers impact will be on the provisions of I&C (Industrial and Commercial), DSR services. In many respects suppliers are already a major influence in DSM, and ToU variable tariffs can be a contributory factor in industrial and commercial processes.

Currently many I&C energy users will purchase energy on a flexible contract, or against an expected profile with an allowable variance. If the site therefore deviates significantly from their procured energy, by either consuming more or less than expected, it is feasible that their supplier can apply a penalty to reflect any imbalance in the supplier's trading regardless of whether or not the an actual penalty for imbalance occurred. It is therefore important that a site shifting or changing their total consumption or profile for DSM/DSR opportunities takes into consideration any negative costs that occur as a result.

Some energy suppliers already allow some of their larger and more sophisticated customers to take a more active role in self-balancing and trading and this is likely to grow in time. Out of this we can expect to see more bespoke and detailed conditions applied that will either restrict sites ability to work with other external programme providers. Or, potentially they will seek to develop their own aggregation capability to assume a more strategic role in the optimisation of participants' behaviour for commercial benefits to the parties who offer the greatest incentives, but minimise risk.

Where the I&C customer has flexibility within their processes, most likely by means of on-site generation, then we are also likely to see an increase in consumers entering into trading and arbitrage behaviours. This already occurs within a very small portion of businesses who have assets that enable them to achieve sufficient volumes to merit the relatively complex analysis. They have sufficient capacity to justify the additional risk that results from seeking

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to profit from adopting changing positions in relation to purchasing fuels, energy and then ensuring that final processes reflect this in real time.

More typically we find that the common role for an energy supplier in the current DSR market is as an energy purchaser, or ‘off-taker’ who purchases any exported power from a participant site through a PPA, (Power Purchase Agreement)

When large suppliers are approached to present a view of ‘if and how’ they expect to employ DSR within their future business operations it is typical not to receive a detailed explanation in response. This is to a large extent understandable, as they are independent commercial companies with responsibilities to their shareholders. It could be easily deemed as compromising to any business that is compelled to state what their strategy is towards the use of specific technologies. There are however a growing number of smaller suppliers who recognise that DSR can potentially bring added value and are openly seeking to promote their intention to commercialise. It is not expected that the large, vertically integrated suppliers with massive investment in generation are likely to adopt potentially ‘disruptive technologies’ quickly or as openly.

SECTION 5

Process development

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The overall scope of the trials required the development of several processes in order to facilitate the commercial trials. The trials would culminate in an operational phase to test DSR within live network conditions. It was therefore necessary that each element of the trials had a repeatable process that could be adopted into BaU effectively in the event of a successful outcome.

The required processes that needed to be designed are listed below:

- Payment model assessment;
- Network assessment for potential participants;
- External engagement / site acquisition;
- Contractual;
- Event Operation;
  - Control Room / Usage criteria
  - Dispatch / Cease
  - Data collection
  - Billing / Settlement
  - Account management and
- Impact assessment (operational and financial).

SECTION 6

Technical Requirements

Technical requirements that needed to be considered and addressed within the scope of a DSR trial or BaU service development can be categorised into a few key areas:

- Use Case / Impact;
- Communications;
- Monitoring;
- Service Operation
- Performance assessment / billing / settlement
- Safety

The context behind and the rationale of each of these categories is described in the following sections.

6.1 Use Case

The purpose of a DNO procuring DSR services is ultimately to address a technical requirement relating to the operation of the network. This will typically be to alleviate constraints within the network as a 'pre-fault' or 'post-fault action'.

6.1.1 Pre-Fault Scenario

Within this use case it is most likely that the requirement for DSR is either as a temporary or permanent alternative to capital works to a portion of network that has a reasonable likelihood of experiencing a brief fault during periods of high demand. As the potential of the fault is only likely to happen on a limited number of occasions, it may the case that by employing DSR to reduce the constraints to within an acceptable margin then capital reinforcement costs could be avoided or deferred. The deferment option could help DNOs, in particular where the long term expectation is that the issue is ephemeral or where capital works are delayed by unavoidable factors.

This mode of use does mean that a realistic potential exists that failure of DSR provision could result in critical network conditions leading to post-fault and ultimately, interruption of supply to the customers on that affected network.

It is potentially the case that the applicability of a DSR solution will be able to be measured using four key metrics, outlined below.

Capacity / Delta Reduction

The reduction necessary within the network can be no greater than the 90% of the available DSR capacity available downstream from the congested point of the network.

Duration / Frequency

The event duration can be no longer that the participating DSR sites can comfortably offer. This may relate to the industrial / commercial process to be affected or availability of fuel to a generator.

Cost of Operation

The payment for the predicted annual use of the DSR facility should be equal to or lower than the alternative methods for addressing the constraint. More detail regarding the financial calculation relating to DSR provision is available in Section 10.1

Reliability

The reliability of the DSR service can be measured on various aspects of the delivery criteria. Firstly there is the likelihood of the respondent being present and ready to act in the event that they receive a dispatch request. Thereafter there is also a risk of communications failures in the process of dispatching or potential operational issues at site that would prevent the dispatch instruction being carried out. Where there are multiple respondents to support a pre-fault constraint it may be possible to use several with a de-rated capacity, but this will not be the case in all instances and is also likely to force up the operational cost from the need to over procure volumes.

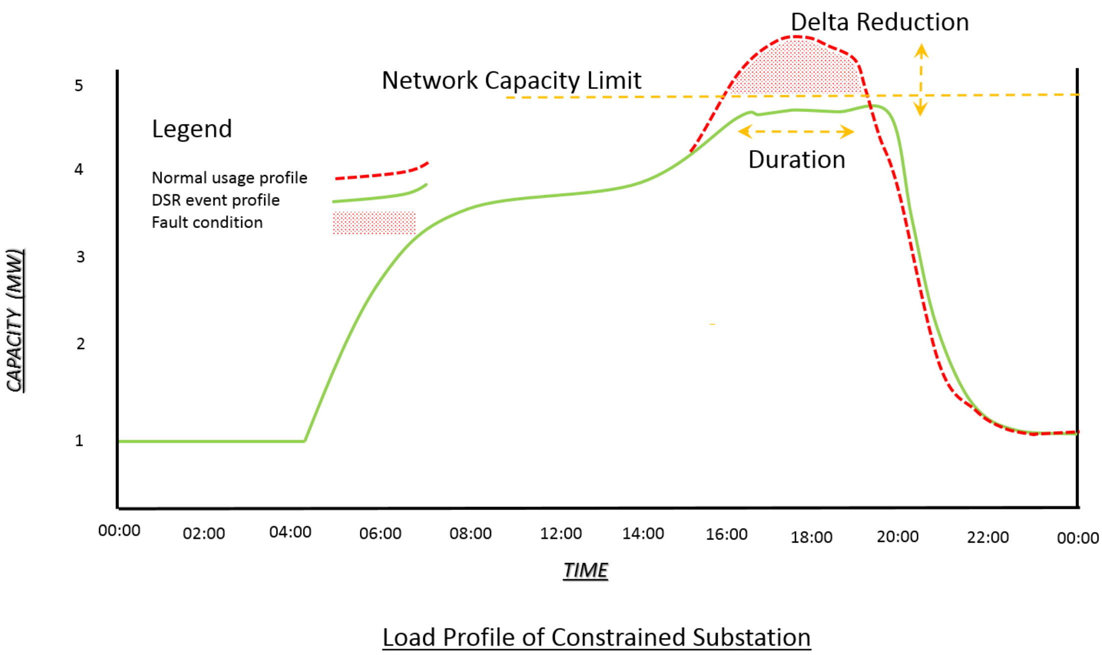

Figure 3 - DSR requirement for constrained substation, load profile

The above diagram demonstrates the assumed load profile of overloaded substation that would be suited to DSR intervention. This is applied on the basis that the annual occurrence of the fault conditions is limited to a relatively small number of days, combined with the accrual of payments being more economical than other management methods. It is also assumed at this stage that impact on the network assets has a direct correlation with the site behavioural change shown in the following diagram.

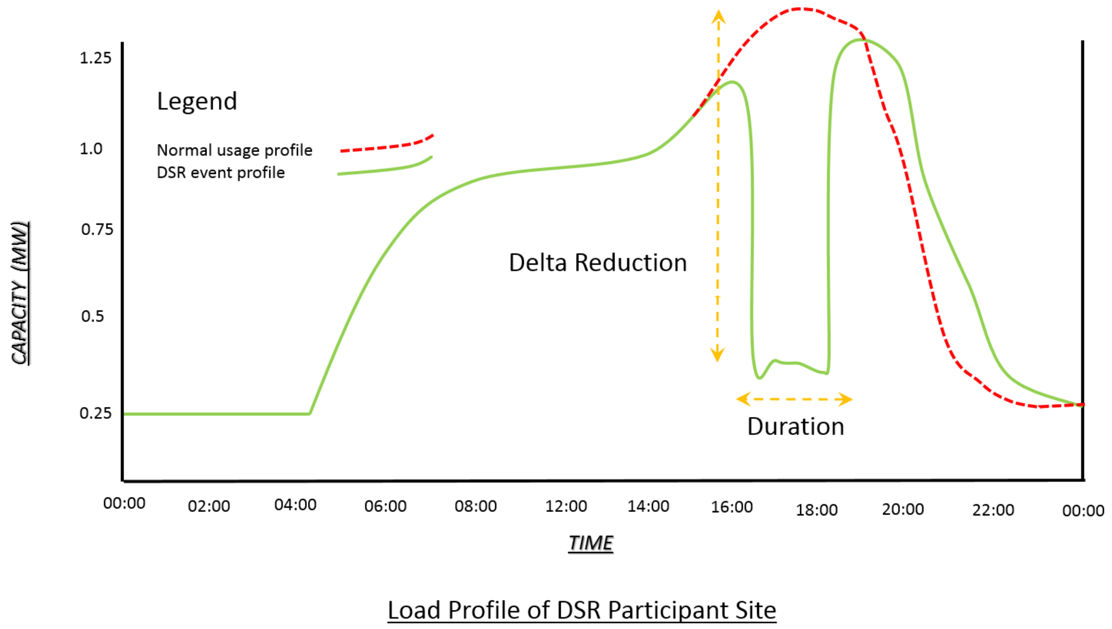

Figure 4 - DSR Event on constrained substation, load profile

6.1.2 Post-Fault Scenario

The case for DSR to be used in a scheme where the purpose is directly following a fault being identified can have varying impacts depending on the nature of the fault and the actual status of the network at that time.

It can be the case that even after a fault has occurred the network may still be operable, just with increased likelihood or risk that a supply interruption may follow. In such circumstances it could be possible to lessen or avoid the loss of supply through reduction in demand on that particular portion of the distribution network.

If a fault results in supply failure, the DSR action at a site(s) connected to the affected area of network may facilitate or assist in return of supplies sooner than expected or improve the stability of the network when primary supply is resumed. DNOs are subject to Guaranteed Standards set by Ofgem that apply to individual customers and involve penalty payments if they do not meet set guidelines. Further information is available on the Ofgem web site.

The criticality of DSR in the initial post fault period if supplies are not immediately disrupted, the reliability requirement for DNO use is comparable with pre-fault requirements, as any deficiency in DSR delivery may result in further deterioration or loss of supply. However, after post-fault scenarios have led to interruption it is arguable that load reduction is of little value. It is also likely that within such circumstances a site with generation will wish to operate this as their own primary supply for business continuity reasons and unlikely to require further incentive from the network operator to operate it.

Within Project FALCON we have designed the trials to test the principals of using DSR as method with which to address potential technical issues, but much of the assessment relates to its financial impact and suitability in terms of reliability and availability. The scope of the trials are therefore limited to predictable economic factors such as planned network and we are therefore restricting the cost and performance analysis to a pre-fault use.

A project by Electricity North West Limited, entitled 'Capacity to Customers' or 'C2C' has attempted to test the viability of working with certain customers to agree commercial terms for post fault arrangements. Further details of this can be found in section 22.7.4. Capacity to Customers – Electricity North West Limited

6.2 Communications

The communications requirements within the trial separate into several categories in relation to the technical requirements of operating the trials. This does not include corporate communications or the recruitment of participants to DNO DSR programmes, as this is covered in section 8.

Technical communications requirements within this section relate to:

- Dispatch and Cease of events; and
- Metering / Monitoring and data collection.

6.2.1 Event Dispatch and Cease

SO operated DSR schemes will generally prefer a dispatch and cease arrangement that is administered through communications that are capable of M2M (machine to machine) communications. By operating on a M2M basis it is expected that any programme operations will benefit from:

- Avoidance of human error;
- Improved reliability;
- Increased speed; and
- Reduced cost of operations

As part of this final trials report, incorporating the results of both winter seasons we will seek to determine a clear requirement and detailed use case that establishes a suitable standard for the DSR control communications. This will be suited to the requirements of the service rather than adopted from alternative DSR programmes that may have differing requirements for speed, reliability and operating costs. Examples of the other programmes and their technical requirements can found in the Appendices of this report.

Within the **(S1)** trials DSR was not planned to be used for critical operations or to support live network operations, in order for the trials to remain under the full control of the project. It was therefore unnecessary to incur the expense of a M2M system to signal the beginning and end of the DSR events. It could even be argued that the frequency, volume and urgency of DNO requirements may never require this level of control. This is most likely to change in the event that DNOs seek to develop a control capability that would enable them to also offer services out to other programmes with standards that merited M2M functionality. We therefore opted to centrally control the notices to participants via a phone dispatch, and manually log the start and stop times for **(S1)**. This was further relaxed in **(S2)** with the adoption of email dispatching in line with increased notice periods for event dispatch.

It was considered that upon receipt of the notifications, an aggregator acting as intermediary on behalf of the site, may use more advanced means, such as automation, to control the event. If low latency, M2M or automated dispatch is required, there is significant prior knowledge regarding this than can be sourced from the existing DSR operations without the necessity to include the added expense within the FALCON commercial trials.

6.2.2 Monitoring / Data Collection

In respect of the trials operation, communications requirements for the asset performance monitoring, it was not necessary to monitor the reductions or generator outputs live. It was, however, important that for two factors were accounted for within the operational processes.

The first is to ensure the trial operations do not negatively impact the normal, safe operations of the network. It was therefore necessary that whoever operated the trial events remained in contact with the control room and participating sites throughout the full duration of each DSR occurrence and ensure that network conditions are maintained within acceptable standards. Secondly, it was also important to ensure that assistance is available to the participants in the event that they experience any issues with DSR delivery and can report and problems that may occur.

On the day following a DSR event, all sites were required to provide a copy of the data for the prior 24 hour period. This presented challenges, as the back office software was hosted within the highly secure environment of WPD’s core systems. In order to maintain the optimal level of security within the system architecture, there are no direct interfaces with the external world via the internet or other perceivably insecure mechanisms. It was therefore necessary to work closely with the internal WPD IR (Information Resource) team to create a new secure file transfer route to receive, scan for threats and store files in a data repository for processing.

During **(S1)** sites contracted via third party aggregators had their data collected by their aggregator, who pushed the files by secure FTP to WPD. Each aggregator had a storage folder designated to their group of participant sites. We could then accurately measure the delta value of the generator before, during and after the event. The **(S1)** trial design was such that any directly contracted sites, would not have an independent intermediary to meter and manage the data transfer process. Therefore, for direct participant sites involved would require an additional smart meter that was to be installed at their site by WPD's Smart Metering division. This was be configured to collect data at 1 min intervals and the data collector would remotely connect to this and download the daily files, before using the same FTP access as aggregators to upload the data for processing.

A variation to the design was required for **(S2)** which necessitated that all sites would require to provide performance data through a new dedicated metering solution. An explanation for the reasons behind this is contained in Section 18 which provides further information behind the **(S1)** results and the dependencies that determined the **(S2)** change request and trial design. During **(S1)** we were focussed on the output of the generators where due to the short duration in the notice period for dispatch, the opportunity to abuse the programme for financial benefit was very limited. As **(S2)** moved to a 7 to 12 day advance notice it was necessary to measure the impact by means of a site consumption cap rather than a delta shift. Although there was no suggestion that any trial participants would modify their behaviour to benefit financially, it was clear that it would be potentially very easy to do and difficult to police. With any significant advance notification a participant could intentionally increase their demand prior to the event, making the delta either easier to achieve or increasing potential earning by increasing the size of delta shift. Therefore different benchmarking and performance monitoring criteria would be necessary.

For **(S2)** Smart Meters were installed in series with the existing Half Hourly settlement meter at each site. By doing so it would be possible to receive back day +1 data to determine the performance of each site against requirements as well as calculate their DSR event payment. WPD Smart Metering provided the meters and installed these, with more detail of the exercise available in section 11. **(S2)** presented similar challenges with **(S1)** to ensure that while achieving this new functionality, there should be no discernible increased risk to WPD system security or data protection. For these reasons a closed process was developed to ensure that communications did not take place via public internet infrastructure. The process consisted of Stark Energy Data Services, as appointed meter reader, dialling each meter securely to collect the daily files. For resilience each meter held five consecutive days of data which would ensure that we would end up with up to five files for each 24 hour period, and minimise any communications or data integrity issues. After each meter was securely downloaded, a secure FTP facility allowed the data to be batch transferred to WPDs closed access repository, where thereafter it could be processed.

6.3 Monitoring

Many parallels exist between the technical requirements for a DNO to monitor DSR events and the event dispatch requirements. As with the dispatch and cease communications, within the FALCON trials we were able to reference the prior and extensive knowledge already developed in relation to remote asset monitoring. Some of this results from other DSR programmes but there is also an independent industry dedicated to M2M communications for a far broader and more complex range of functions beyond those necessary within the FALCON trial.

It was, however, very important to the trial that we were able to gain a detailed insight to both the performance of participating sites and their impact on the network during DSR events. It was therefore necessary for the trial to include metering that enabled visibility of any detectable impact on the network. Metering at all sites was set at a minimum design standard of 1 minute intervals in order that we ensure, not only an appropriate volume of capacity is reduced or generated, but that it does so in the appropriate way as to satisfy the DSR requirement set out by the DNO. This is a very important point of note in relation to both SO and DNO requirements on the most part. When DSR is procured for such purposes as system balancing or constraint management, the payments offered by the programme operator are not for the purchase of energy. This is a subtle, but very important, factor in understanding how DSR operates and its role within the broader market mechanics.

When a DNO or SO uses DSR they will, in most cases, see this as ‘demand reduction’ unless it is significant enough in capacity to reverse the power flow at the 11kV primary substation or 33kV bulk supply. Under this circumstance, the DNO would likely regard it differently. When an event is triggered, the programme operator is not the consumer or owner of the electricity commodity at any stage. The operator is purchasing the impact / effect, which will generally be a behavioural change that reduces an imbalance or shortage of capacity. It is therefore essential that the profile of that delivery meets the requirement for addressing the imbalance or shortage. Generally, this will be subject to two factors; capacity and duration rather than a volume which would be more commonly associated with a commodity purchase and typically only measured to a 30 minute settlement period.

The diagram below shows an example profile for a DSR event that is reducing the demand over the period of an evening peak. In this instance, a dispatch is issued at 15:15 with a 30 minute response. The baseline is established from the average in the preceding five minutes, from which the site will drop an agreed delta measurement and maintain this reduced demand level until a cease instruction allows them to return to normal operations at 18:15. By measuring this at 1 min intervals we can see a detailed shape of the site’s performance against the reduced level for maximum demand, shown with a solid green line.

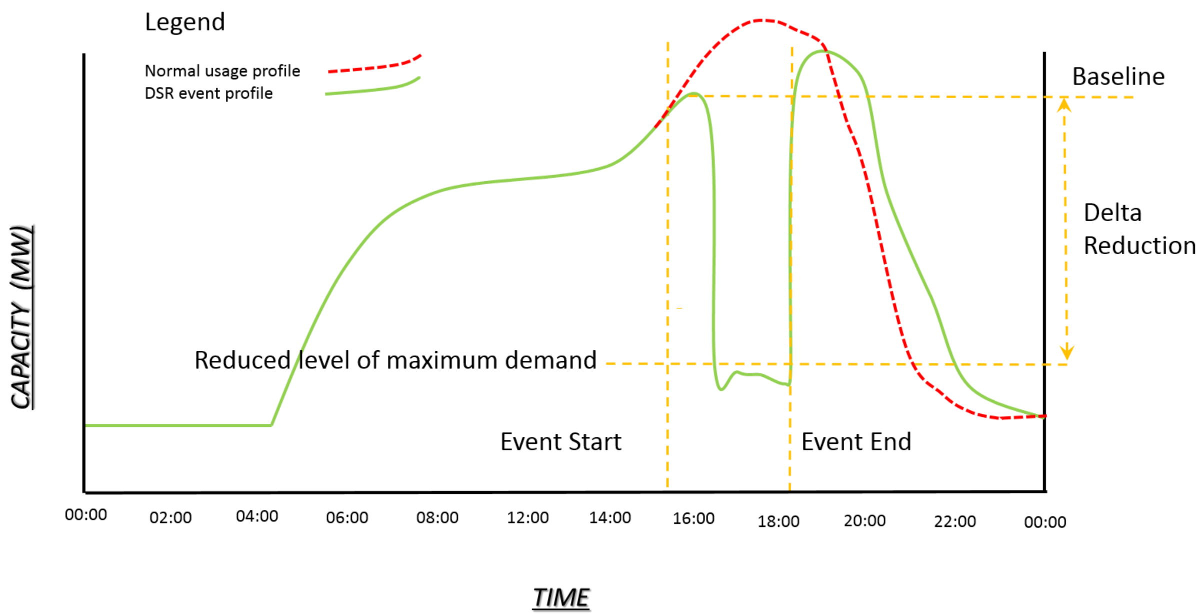

Figure 5 - DSR Event, demand profile

Compare this to the next diagram, in which the half hourly consumption periods reflect the volumes of energy consumed by the site in blue blocks, consistent with metering that would normally be used for settlement. The green line that reflects the accurate 1 minute consumption during the course of day demonstrates how during periods such that between 15:30 to 16:00 (Period 31) and 17:30 to 18:00 (period 35) there can appear to be a disparity with that of the volume measurement. This is particularly obvious at the beginning and end of each 30 minute period as the volume will offer an average value of the granular 1 minute intervals.

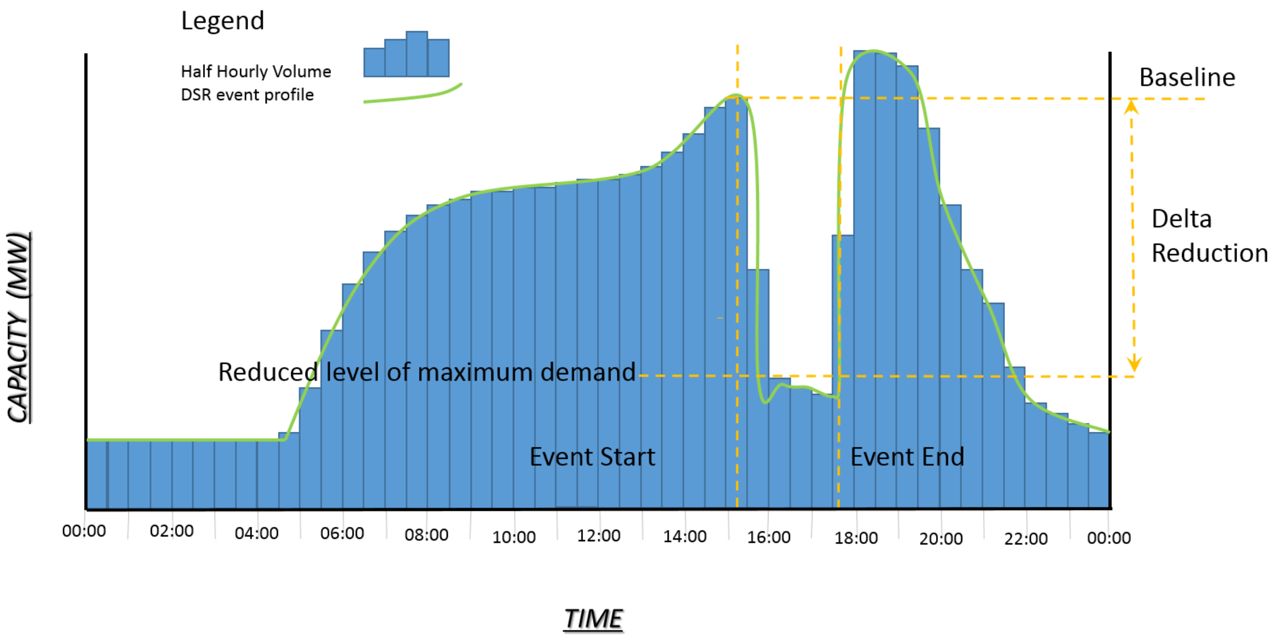

Figure 6 - DSR Event, demand profile, half hourly granularity

The third and final diagram in this section highlights how it is possible without adequate granularity it would be theoretically possible that a site being measured with standard half hourly settlement metering, could appear to be achieving a consistent reduced maximum demand. However, the blue volume measurement would be the same for both the green and red dotted profile lines. If the theoretic profile was the actual consumption of the site, then it would not have provided the network with the necessary, consistent reduction and could contribute to a capacity shortage for brief periods and potentially result in fault conditions.

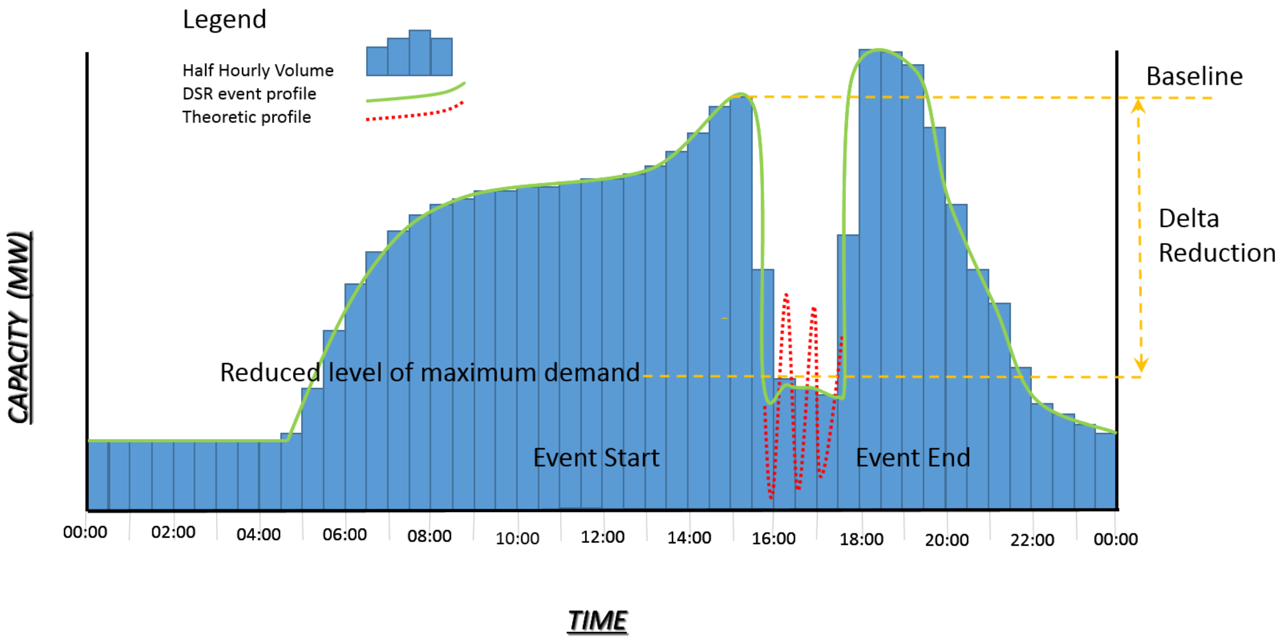

Figure 7- DSR event, limitations of half hourly monitoring

Another important aspect of the monitoring was to establish if there were any clear correlations between the demand reduction action at a distribution connected site and the network impact upstream. Also, whether there were any other factors that result in either a consistent or unpredictable variance. During this assessment it was desired that the trials could determine if there are any other contributory factors that may result in a sizable variance between capacities that a DNO would need to contract in order to achieve the upstream impact on the network from the site.

It has previously been assumed that this impact will be the same and, if a 1MW DSR delta in consumption is carried out, either by load reduction or generation this would be the same measurement experienced at the 11kV substation. Also within this, it was important to identify if there was any lag in the time it takes to detect the impact of a reduction on the network. Both of these factors were important in developing the DNO DSR requirement and establishing policies relating to when and how best to utilise DSR to manage future constraints.

To assist in the assessment of both of the true impact on the network, Project FALCON installed supplemental network metering on 11kV substations serving participant sites, which were capable of accurately measuring the demand at 1 min intervals. This would facilitate the ability to compare the site and network data at a variety of different times and conditions to establish if any rules may be apparent.

During **(S2)** the metering was modified and a further level of data was captured through installing it on 33kV assets also.

6.4 Operation

The technical requirements of the commercial trials were largely confined to metering of the events, as described in the previous section, and the associated processing of the gathered data. The scope was focussed on being able to deliver key learning in the following areas:

- Determining the impact on the network;
- Reliability of predicting events within the dispatch notice period
- Relative cost of Load Reduction and Distributed generation in relation to alternatives
- Assessing the reliability of participant performance;
  - Speed of response
  - Duration
  - Capacity
- Measuring of the sites against expected volume; and
- Accurately settling customer payments.

One of the major deliverables for the project is therefore, a back office software system that assesses the performance and meets the accounting requirements of generating customer statements including payment calculations. The trial software was required to demonstrate the functional principles expected within a full blown, enterprise software solution developed for managing a larger volume of customers, but at a scale that is appropriate to the trial, so as to minimise costs. As DNO's do not have existing systems similar to those of suppliers who already have large enterprise software deployments to manage customer contact and billing, the developed solution needed to be standalone and not just a concomitant module to a legacy structure. Furthermore, given that there will be a requirement within the industry for such software in future, every attempt has been made to ensure that a scalable solution was established. This will contribute to the ongoing development of a BaU capability for all DNO's to meet their new necessity to directly manage performance contracts with connected sites.

6.5 Connections

A very important aspect of the commercial technique 6, where the reduction of demand is facilitated by embedded generation, is to ensure it is connected to the network in a safe manner that allows the site controls to manage the transition between supplies without interruption. With almost all participant sites, particularly those that have invested heavily in the purchase and maintenance of a stand-by asset(s), it is vital that any DSR scheme does not negatively impact on their business continuity arrangements. Much of the ability to achieve this is incumbent on having the correct connection permissions from the DNO, as well the appropriate controls and switchgear installed.

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The design, operation and permissions were based on the assumption that the site will run predominantly in one of two modes. These are 'Islanded' and 'Synchronised'. There are, however, different ways of achieving and operating particularly under 'island mode' and these will affect the potential risk to continuity of a site with generation. These different modes are described further in the following section.

For more detailed information regarding connections and protection please visit the Energy Networks Association website:

http://www.energynetworks.org/electricity/engineering/distributed-generation/distributed-generation.html

6.5.1 Island Mode

When in 'island mode' a generator will provide its output to support the local network only. This can be more easily explained with the assistance of the simple, single-line network schematic below:

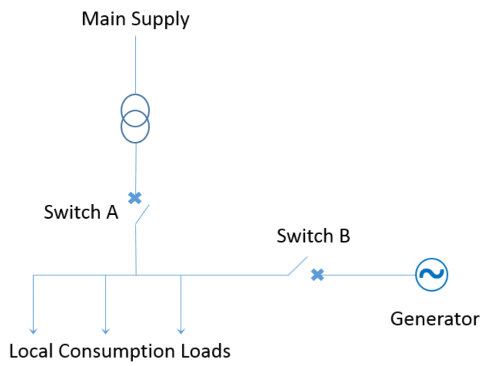

Figure 8 - Simple network schematic

Under normal operating conditions where the primary electricity supply comes from the DNO (main supply) then 'Switch A' would be in the closed position, allowing the flow of power to the local consumption loads via the bus bar. During this normal mode, 'Switch B' would be open, and therefore preventing the local generator from supplying the bus bar concurrently with the mains supply.

In order to operate in local 'island mode' with power from the generator, the switch positions would require to be reversed so that the main supply is isolated while the local generation is operating. In order to maintain this, it is necessary that the generator is sized appropriately to meet the local consumption loads, but not oversized by a significant margin as it is unable to export excess power due to the open position of 'Switch A'

6.5.2 Synchronised

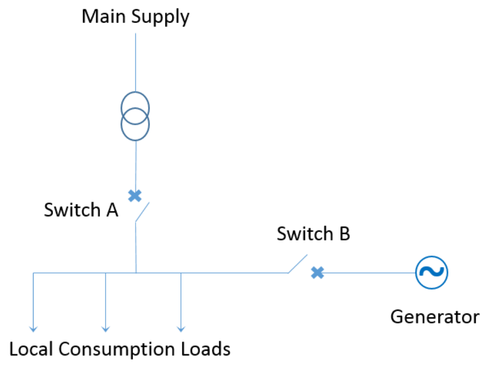

Figure 9 - Simple network schematic

When a generator is operating in a 'synchronised' arrangement then both 'Switch A' and 'Switch B' are closed at the same time. This offers greater levels of functionality and resilience as if either the main or local supply fails, the other should remain present, maintaining the continuity of supply, assuming the generator is adequately sized to carry the full load present at the time of mains loss.

By maintain the continuous synchronisation with the mains, it is possible to either continue to import power for any shortfall or export excess electricity from the generator if there is imbalance between the local load and available generation.

This does however increase both risk to the network and local site in the event of a fault condition and there are some compromises that result, generally in relation to the cost and conditions applied to the granting of a permission to synchronise over and above those of island mode.

It must also be noted that even when permitted to full synchronise local generation with the main supply, it is often the case that there will still exist restrictions over the import and export capacity allowed.

6.5.3 Load Transfer

The connection permissions that are granted are often as important for the brief period during which loads are transferred from mains to local or vice versa than for the extended duration it may operate for once running.

Unless permissions have been given expressly by the DNO, then under no circumstances should the site allow main supply and local generation to be interconnected together on the same bus bar. This is a relatively common configuration, particularly with emergency back-up assets which are only expected to run in the event that mains is unavailable anyway. However when mains supply has been restored, the site will require to carry out a 'break transfer' in order to switch back to the normal primary supply. This transfer mode, sometimes otherwise known as 'break before make' does limit the ability to test the generator regularly without interruption to the site and a 2nd interruption is necessary when returning to mains following a critical supply event.

To avoid the secondary interruption and improve the ability to test the generator regularly without incurring a loss of supply the most common option is to gain a STP (Short Term Parallel) connection permission. This offers a compromise between the total exclusion of any synchronisation and the typically more expensive alternative of full or long term synchronisation as described in section 6.5.2.

With STP it is accepted by the DNO that a brief period of synchronisation, where both main supply and local generation are concurrent, will generally be of a lower acceptable risk than maintaining over an extended period. It is therefore possible to allow a site to apply the principal for a period of around five to ten minutes in order to start local generation, synchronise and stabilise the supply before enacting a controlled disconnection of the mains, thus avoiding interruptions. This can also be applied in a reversed sequence to allow the site to return to a primary mains supply without negatively impacting the concatenation of the two sources.

6.5.4 Engineering Recommendations for Protection

The proper title is ER G59 or Engineering Recommendation G59. G59 is a generic term, G59-1 is the original standard authored in 1998 and revised to G59-2 in 2010. It has seen further review and updating resulting in the current G59-3 being applied in 2014. This report section refers to the recommendations and guidelines for connecting embedded generation to utility supplies for long and short term duration.

Government policy, environmental concerns and advantages to the national grid balancing mechanism, led the way to it being increasingly desirable to allow small embedded generation sources to be able to feed and contribute power into the grid infrastructure, an infrastructure almost exclusively controlled upstream by the national grid. If an unpredictable and uncontrolled quantity of wind turbines and embedded generation were to be allowed to feed into the grid, some regulated basic protocols would be needed.

ER G59 attempts to specify basic functionality requirements to protect both the grid and the embedded power generation.

One of the recommendations within the requirement is for mains failure detection whilst the generator system is in parallel with the mains.

A traditional phase failure relay, sensing voltage only, may not detect a mains failure due to the generator operating in parallel and supplying power at the detection point.

Many manufacturers have specific G59 detection relays that will supervise the system when in parallel, constantly monitoring the mains/generator common voltage and generator output current to detect rapid changes in characteristics which would identify that the mains is no longer present and a mains failure has occurred.

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A common misconception is that the G59 relay protects workers upstream if they isolate at HV and commence to work on the network, assuming several downstream generators will keep the equipment live and in a dangerous condition. Firstly any planned outage would where possible, be re-fed via an alternative path on the grid to minimise outage and as a minimum you will be informed if this is not possible. Also a robust safe working practice will test and ensure the bus is dead before commencement of work, thirdly they will earth the power rail at the point on the network on which they are working.

Predominantly the G59 relay protection guards against unplanned system failure for both parties (grid and generator owner). The mains disconnection has to occur quickly for two reasons:

1. - If the dead network is not disconnected quickly, the site embedded generation will attempt to supply the local surrounding network and fail on over current, making the point of having the generators useless.

2. - Depending on where geographically the site is on the distribution network, an attempt to bypass the network fault will be made or auto re-closers on the network will attempt to reconnect power a number of times to see if the fault was temporary (a fallen tree for example). Either way, power would reappear on the utility mains causing a crash synchronisation if embedded generation was still attached.

Depending on the size of the generator seeking a connection permission, its location and what else is already connected within that proximity, there are a number of other parameters in addition to 'loss of mains' that can be monitored and managed using G59.

- under and over voltage
- under and over frequency
- Phase vector shift
- NVD (Neutral Voltage Displacement)
- RoCoF (Rapid Change of Frequency)
- Reverse Power
- Over Current
- Earth Fault

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SECTION 7

Commercial Model

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The establishment of suitable commercial models for DNOs to access DSR as an alternative to capital investment in the network is at the heart of the FALCON Commercial Trials. It is critical for a DNO to establish a true value for DSR and test the associated sensitivities relating to its 'use case'. Although previous trials have been carried out by DNOs to test the effectiveness of DSR as a new network tool, it has been isolated to the technical aspects of the service operation. In order to continue the service development principals, it is necessary to establish its financial effectiveness in relation to the other alternatives available of which the number of potential options are increasing with the introduction of alternative 'smart' technologies.

We did not assume that DSR will automatically be rolled out as a BaU method simply because it is a new alternative, as there are many acceptance criteria it must satisfy first. Any benefits over other alternatives need to be identified and the magnitude and nature of any advantages established against conventional reinforcement as well as any other new substitute solutions.

DSR has some added complications to consider. Typically, all the other techniques that could be employed are capital investments that have relatively fixed assessment parameters as outlined below:

- **Cost** – normally a fixed capital expenditure with relatively low operational or maintenance costs
- **Duration** - capital upgrades can have a balance sheet depreciation of 15+ years and an actual lifecycle even greater
- **Reliability** - once upgraded, capital investments typically have a predictable reliability and degradation curve
- **Ease / Speed of Deployment** - highly variable depending on technique. Significant upgrades can often include a variety of associated work including design, wayleaves, civil works, etc. More complex civil projects can incur delays that are not conducive to maintaining constraints within acceptable parameters.
- **Requirement Certainty** – a constraint may be transient or predicted but not result in a permanent need.
- **Autonomy** – with the majority of engineering techniques the DNO does not require the added participation of third parties when reinforcement is required and can opt to upgrade without uncertainty of sourcing participants.

7.1 Establishing a trials budget

In order to have a reasonable likelihood of BaU application, it was necessary for the use of DSR to offer tangible advantages over conventional reinforcement. Using the assessment parameters stated above for establishing a trials budget, it was necessary that the annual cost for DSR was lower than the annualised cost of conventional reinforcement.

On this basis, a sample reinforcement cost to increase capacity of an 11kV substation can be calculated as follows:

$$\frac{(capital\ cost\ of\ reinforcement \div operational\ life\ in\ years) + annual\ maintenance}{Megawatts\ of\ Additional\ Capacity} =$$

$$annual\ DSR\ budget\ per\ Megawatt$$

Once the budget was established, per MW it was possible to calculate how it would be extrapolated to customer payment. It was necessary to determine the volume of DSR required in terms of the expected number of hours that a constraint is likely to require to be managed by means of DSR.

Therefore, the calculation of the payment to be paid to the participant is:

$$\frac{annual\ DSR\ budget\ per\ MW}{total\ annual\ duration\ of\ expected\ DSR\ operation} = Hourly\ utilisation\ rate\ (£\ per\ MWh)$$

Within the FALCON trials, the network areas selected are not subject to any critical constraints that require immediate reinforcement. This enabled our operational scope to widely accept a variety of site types, locations within the trials area and to base the operations on a hypothetical financial model. A DSR volume of up to 40 hours over the period of each winter was assumed.

The benefit to a participating site is not limited solely to payment offered explicitly for FALCON operation. There are also implicit costs, revenue and savings to be considered in order to establish the full commercial impact of trials participation. Below is an approximation of the potential financial impact to a site with a 1MW diesel generator used to displace demand for 40 hours in conjunction with FALCON and Triad.

Table 1 - Estimated finances of participant incentive

Description	Unit Price (MW)	Total
FALCON payment	£300	£12,000
Electricity import avoided	£75	£3,000
DuoS avoided	£82.60	£3,300
Triad avoided	£25,450	£25,450
Fuel Cost	£148.50	£5,940
TOTAL		£37,810

Notes –

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- It is assumed that all the electricity generated is being consumed on site and therefore no GDUoS or electricity export payments are included in the above table
- Generator efficiency based upon 270 litre diesel per MWh
- Red diesel price 55p per litre. Average price for **(S2)**. *Source: www.boilerjuice.com/*

7.2 Cost versus benefits

The *cost vs benefit* is only workable if it meets the requirements of all participating parties. As part of Project FALCON we assessed the viability of the available budgets for reinforcement to be attributed to a new DSR programme. This raises the potential of a disconnect between the available budget from a DNO as part of a well justified business plan and the expectations of any participant who will have a minimum expectation that will require to be met in order to secure their involvement. It is also worth noting that this is not necessarily a binary function, and that both the programme sign-up results and the quality of service delivery may be sensitive to the level of payment.

A participant may join the programme if their minimum expectations are met, but if the payment was higher, we may identify increased levels of capacity. In addition, the minimum payment level may result in a site agreeing but attaching a limited value to meeting their obligations under the performance contract as there are no punitive measures beyond that of 'loss of opportunity'. If a participant attaches inadequate importance to the conditions against competing operational priorities then performance may not meet the expectations of the programme operator.

Only a portion of the trials data will be able to capture the true effect of price, as a sensitivity within the site performance as results data may also be accountable to conditions outside of a site's influence e.g. a mechanical or communications failure on the day of a DSR event. We therefore sought to carry out attitudinal analysis at various stages throughout the trial to determine the primary factors and their prevalence on the final performance results. Interestingly the analysis from **(S1)** did reveal a number of claims that price was an important issue, particularly in the case of recruiting load reduction, which as the report reveals, proved more difficult than generators. As a result the payments for **(S2)** were increased to determine if this was indeed the aspect that was restricting potential participants from joining the FALCON trials. While the payment for generator participants was established at £300 per MWh, the budget for load reduction was rolled over allowing it to be used for Load Reduction incentives. As there were no load reduction participants in **(S1)** this meant that the **(S2)** payment was doubled to £600 per MWh for **(S2)**.

It should however be noted that the increased incentive payment would not be sustainable within the majority of DNO BaU applications and would serve to act as an inoculating factor that may establish a high price precedent that would likely impede the development of commercial DSR services by DNOs.

7.3 Contract Development

The contractual requirements for the DSR service is relatively unprecedented within the relationship between a DNO and consumers connected to their network. Under normal circumstances, any legal agreement would only relate to the connection conditions of a site as DNOs own and operate the distribution network of towers and cables that bring electricity from our national transmission network to homes and businesses. They don't sell electricity to consumers and don't bill directly for any services, other than capital works associated with provision of connections.

Therefore entirely new contracts for **(S1)** and **(S2)** needed to be developed and approved so that an appropriate relationships could be created with existing connected sites. This needed to enable a performance related payment to be made which reflected performance achieved against expected outcome. As a result, the contracts needed to reflect a clear description of the expected action to be taken by the site, along with any payments, penalties or any associated remedial action that would be taken in the event of non-performance. In addition the contract required to include all the standard legal sections normally found within a 'service agreement'.

The contracts that pre-exist within the industry for provision of DSR services by other parties such as National Grid have in the past received criticism for the length and complexity, and have even been accused of acting as a barrier to programme entry. It was therefore a key objective to simplify the contract for Project FALCON and seek attitudinal feedback from the potential counterparties as to its clarity and ease of understanding.

In simplifying contracts and attempting to make it as easy as possible to understand there were clear limitations on the number of terms to be included. As a performance contract it was necessary to include detail of performance assessment and payment details;

1. **Parties** – The names and addresses of all the contracting parties should be clearly stated.
2. **Definitions and Interpretations** – – A number of specific terms needed to be clarified due to being particular to the proposed services. For example - "Demand Response" means the regulation of the amount of electricity consumed and/or generated by a Site to achieve the Agreed Capacity. and "Policies" means any instructions, rules or policies issued by WPD from time to time, including without limitation Policy Document: LE7 Relating to Bribery;
3. **Payment Provisions** – The value to be paid allows provision for an availability and utilisation payment enabling the terms to be flexible to support programmes with different payment models. The FALCON trial is testing an Utilisation only payment mechanism but the 'Availability' option was retained in the event that contracts and systems may end up in BaU, and be required for particular circumstances in the future.
4. **Description of Services** – Simplification of the description is particularly difficult as there are many variables relating to the performance of the service delivery that in turn affects the payment provisions also. It is therefore necessary to include the performance and payment algorithms, developed specifically for the FALCON trials.
5. **Term of contract** – The contract duration for the trial has been defined two years, during winter. This reflects a period during which the service is most likely to be required due to

high energy demand. In addition any sites that normally provide STOR services may be out of contract and avoid contractual conflicts with National Grid's terms of availability.

6. **Limitation of liability**
7. **Termination provisions**
8. **Dispute Resolution** – The procedure to be followed if the parties have a dispute should be included. Inclusive of an option for arbitration or mediation where the issue cannot be resolved through internal escalation.
9. **Confidentiality** – restriction of disclosure of any technical information relating to the trials
10. **Force Majeure** – This clause should cover situations where performance of the contract is impossible through no fault of either party. For example, if there is a natural disaster or civil unrest.

As sections 3 and 4 are, in their own rights, complicated and potentially difficult to understand, a set of assistance notes were provided in order to offer a graphical explanation to the performance monitoring, targets and financial settlements. Extracts of this can be viewed in sections 10 , 14 and 15.1

The contract was presented to WPD's lawyers for review and the content to be revised into a format that would conform to the style of WPD's existing external contract documents. In addition to the standard legal terms, it was necessary to determine a description of the intended service along with the parameters that would be agreed by each site as their delivery capacity and means of delivery.

A simple pair of tables at the front of the contract detail the DSR parameters along with the contracted party and site or sites, in the case of the participating Aggregators. The second page contained the signing element of the contract. Images of the **(S1)** contract are shown below:

Demand Response Agreement - FALCON

Between:

(1) Western Power Distribution (West Midlands) plc (company number: 0360057) whose registered office is at Avonbank, Feeder Road, Bristol BS2 0TB (**"WPD"**); and

(2) ______________________ Limited (company number: __________) whose registered office is at ______________________________________ (the **"Energy Partner"**).

Date of Agreement (date of signature):	
Season(s)	1st Nov 2013 – 28th Feb 2014 1st Nov 2014 – 28th Feb 2015
Availability Window	16:00 to 20:00 Monday - Friday (inclusive)
Response Time	**30** minutes
Energy Partner Authorised Person(s)	[insert name(s) of Energy Partner individual(s)]
Contact Method	[insert email address / telephone number]
Control Room Contact	Name: Gary Swandells Email: ggswandells9@westernpower.co.uk Telephone number:

Site(s)	**MPAN(s)**	**Agreed Capacity (MW)***

*Note: Agreed Capacity is represented in the Payment Calculation in Schedule 2 as "CM".

Please note: The parties hereby acknowledge that: (a) the provision of the Services; (b) the compliance with any Instruction issued by WPD; and (c) any participation in Project FALCON by the Energy Partner and/or its subcontractors is entirely voluntary.

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Figure 10 - Participation details of contract

To the extent that the terms of this Agreement conflict with any of the rights or obligations of the parties under the Electricity Act 1989, the Utilities Act 2000, the Energy Acts 2008 – 2011, the National Terms of Connection and any other licences, codes or industry agreements related to such legislation (the **"Electricity Regulations"**), the terms of the Electricity Regulations shall prevail.

We agree to be bound by the Agreement (as defined in sub-clause 1.1 (Definitions and Interpretation) of the attached terms and conditions).

Signed on behalf of Western Power Distribution (West Midlands) plc:

Signature: ______________________________

Name: ______________________________

Role: ______________________________

Signed on behalf of: ______________________:

Signature: ______________________________

Name: ______________________________

Role: ______________________________

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Figure 11 - Signatory page of contract

As a performance type contract, the third and fourth pages are for schedule 1 and 2;

11. Demand Response Procedure
12. **Performance Calculations** - The algorithms for how sites will be measured and payments calculated (section10.1)

The contract was condensed into a total seven pages, with the final three presenting the general terms and conditions.

A full copy of the **(S1)** contract is available as an appendix in section 19.9

After the approved contract was available from the solicitors, it was circulated to the Aggregators. They were offered the opportunity to provide their views on the contract and, if satisfied, confirm that they wished to participate in the trials. In order to provide help with the understanding of the algorithms, the contract was accompanied by some assistance notes containing supporting notes and graphical representations of the algorithms. The diagrams can be viewed in section 13.1

Five of the six Aggregators contributed to two further revisions with minor changes that was then able to be approved by their own legal representatives. These were all completed and returned with the exception of **(Ag7)** who were not proceeding well with EP recruitment and therefore declined to complete the contract.

The general feedback received about the contract was largely very positive and in particular the benefit of the supporting assistance notes.

The alterations for the **(S2)** contract were relatively limited as many of the base principals remained the same. However as the operational principals were different and the measurement shifted to capping of demand rather than by a delta shift there were two areas that required to completed changed.

Demand Response Procedure

1. The Season consists of 17 weeks from 1 November 2014 to 28 February 2014 (inclusive). Demand Response may be carried out between 16:00 to 20:00 (inclusive) on Monday to Friday (inclusive) in each week of the Season.
2. By 17:00 on each Monday of the Season, the Control Room Contact shall provide the DR Schedule to the Energy Partner ("you") for each Site for the following week via the Contact Method, which you must acknowledge receipt of to the Control Room Contact by 12:00 on the following day (Tuesday).
3. The DR Schedule will set out when each Response Period is to start and finish for each day of the week. A Response Period is the exact period during which the Consumption Target is to be maintained: it will not be less than 1 hour or more than 2

hours, but there may be some days when there is no Response Period at all. The Consumption Target for each Site is set out on the front page of this Agreement.

4. If you become aware of any circumstances which may affect the ability of a Site to meet the requirements of the DR Schedule, you must notify the Control Room Contact in advance by email as soon as reasonably practicable.

5. During each Response Period, you must procure that:

   (a) the Demand Response is carried out at each Site in accordance with the DR Schedule for that week;

   (b) the Demand Response ceases at each Site at the end of the Response Period or, if earlier, as requested by the Control Room Contact; and

   (c) the Control Room Contact is notified by telephone if a Site is unable to carry out the Demand Response.

6. The ability of each Site to maintain the Consumption Target during each Response Period will be measured in one minute intervals. The Payment Rate will be calculated on a pro-rated basis for each minute during a Response Period as follows:

   (a) For each minute that a Site maintains greater than or equal to 90% of the Desired Delta during a Response Period, 100% of the Payment Rate is due in respect of that Site up to the amount of the Consumption Target. No additional payment is due for exceeding the Consumption Target; and

   (b) For each minute that a Site achieves less than 90% of the Desired Delta during a Response Period, the Payment Rate shall be reduced by 2% for each 1% that the Site achieved less than the Consumption Target, so that 0% of the Payment Rate would be due if 50% (or less) of the Consumption Target was achieved. (Terms and Conditions)

Performance Calculations

As with **(S1)** the performance calculations were made available primarily through a participant briefing document that gave the full payment calculations, but also included a helpful explanation of how they work and a graphical representation of their impact. On this basis it was only necessary to the desired reduction or generation value that the site would provide during a DSR event and the resulting target consumption or cap that would represent their contractual target. These were contained in the modified pair of tables at the front of the contract.

A full copy of the **(S2)** contract is available as an appendix in section 19.10

SECTION 8

Customer Engagement

Proactive customer engagement is a relatively new proposition for DNO's as the main focus of the business is traditionally that of an engineering organisation, focussed on maintenance of the network. As a distribution business WPD own the system assets over 4 franchise areas, including 220,000km of network and 269,000 transformers plus associated switchgear.

Traditionally the main focus of the core business is responsibility for:

- Maintaining the electricity network on a daily basis;
- Repairing the electricity network when faults occur;
- Reinforcing the electricity network to cope with changes in the pattern of demand; and
- Extending the network to connect new customers.

With the focus largely being on the assets themselves, the majority of all customer interactions are either dealing with new connection requests, resolving issues raised by existing customers' and general notifications in advance of planned works.

DSR is not a solution that can be applied unilaterally by WPD without the support of external participants willing and able to change their demand patterns on request. By its very nature of being something that is being trialled also means that it is not necessarily an opportunity with which the majority of users will be familiar. Consequently it is necessary to educate, as well as recruit.

8.1 Direct engagement

In creating the capability to operate the service directly with participants, there are several considerations that a DNO requires to address in order to establish its proficiency. This report has already identified some of the core requirements, such as contracts and back office systems that are requisite regardless of engagement model. There are several others however, that would not only be new functions within the existing business structure, but could considerably alter the scope and scale of the existing business structure by the engagement model chosen

Traditionally DNO's have limited ongoing direct relationships with network users, outside of provision of new connections and resolving faults. Some large property developers may have named contacts or an account manager due to the volume of new connections that they are responsible for, but beyond this the customer engagement resources within a DNO are limited. Establishing a new capability within the business to recruit, manage and operate the participants is considerable and requires scrutiny to determine the most appropriate channels.

The barriers required to be overcome are a combination of market conditions and physical capabilities, as outlined below.

Market barriers

In order to be able to recruit participants a DNO should be able to offer a reflective value and capability in line with existing parties. This can be somewhat confusing as it can potentially be interpreted that aggregators, as well as SO, services are in conflict with DNO service requirements. This is largely due to the SO balancing services being operated under a contracts that restrict participants from being able to offer any other services to other DSR programmes.

Aggregators do not operate their own DSR service programmes, they provide access for participants for a share of the benefits; they are therefore restricted by the DSR programme operators' conditions. One of the primary functions of the aggregator is, therefore, to access the benefits of multiple revenue generating schemes and, by optimising a sites' participation within them. By doing so, they can increase the total financial benefit. Within such an environment it would be likely that to secure exclusive access to sites for DSR use, a DNO would need to compete with the typical incentives accessible from other schemes.

In the case of the SO Balancing services this is likely to necessitate a payment model that offers an availability payment as well as utilisation. In the majority of instances, sites will be of a capacity lower than the 3MW direct contract threshold and will be working with an aggregator. The precedent set by the rates within the existing market are unlikely to be determined by the SIM to be more economic than either conventional reinforcement or techniques 1 – 4. It is therefore important that, within the FALCON trial, the barriers and any solutions were identified that will enable DSR to be rolled out at a cost that is justified and appropriate given the range of alternatives.

In order to address the SO barriers, a working group was established in association with all of the DNOs and NGET as the SO. It was chaired by the Energy Networks Association and Invitations were extended for suppliers and other possible programme operators to present their requirements. The group's focus was to consider and develop the potential of a shared service framework, which addresses conflicts and synergies between the parties. A proposal of a new set of arrangements has been developed that will enable sharing of a sites capability between programmes to ensure optimised value to all parties. More detail on this is available in section 16.

Should the SO and DNO sharing framework be accomplished and the conflict between the programmes eliminated, it is anticipated that it would need further development in order to be accessible to aggregators. It is ostensible that an aggregator will still be able to offer increased value over that of a DNO directly, at least for sites below 3MW. Over recent years, there has been increasing suggestion of a role transition by DNOs to a new and more active constituent of the network. It is typically referred to as DSO (Distribution System Operator).

The DSO section of this report (section 17) offers one view on what may be the broader roles and responsibilities for a DSO in the future. It's commonly recognised among the varying predictions of what this may include, that there will be a requirement to interact more closely with users of networks to understand and influence their behaviour. The applications for this are widespread, but may include the ability of a DSO to develop aggregation capability for their own use, but also to offer services to the same service operators that aggregators do currently, or intend to in the future. This would result in DSO's potentially offering capacity to other DSR schemes such as those operated by the SO. In turn, if a participant is already working with an aggregator then an interesting conflict could develop where the SO could contract in a variety of different ways.

- Directly with a site where it has sufficient capacity
- Through an aggregator
- Through a DSO with aggregation capability

This long term view carries many parallels with immediate challenges that a DNO will require to address in order to create internal resources necessary to operate a commercial DSR service or as part of the transition to full DSO.

Direct Proposition

In order to establish a direct proposition there are various skills and capabilities that currently don't exist with a DNO business, or at a scale that would support an operational DSR capability. Much of this relates to relationship development and management which is necessary to establish and manage participants engaged within performance contracts.

The process for **T5** and **T6** are potentially quite different as there can be some assumed behaviours associated with distributed generation sites that will make them more easily identified that are unlikely to be as obvious with interrupting, reducing or deferring industrial processes. It is also the case that DNOs should have records of the majority of connected generation located within their own networks, which is a significant advantage in assessing the case to use DSR.

In order to identify potential sites with generation not already known to the DNO and for **T5** it will need to have the capability to contact and communicate with potential sites. Due to the use case for DNOs being geographically sensitive, it may be that this resembles a professional and trained sales channel function that includes cold calling, either physically or through alternative means such as phone and email. After contact is established, it is necessary to communicate the value proposition to determine any appetite to participate and then assess the site's potential capacity.

Assuming that the engagement process is successful, further resources will be necessary to negotiate, agree, contract and manage the relationship. In addition there will be technical requirements, as even in the event that simple service dispatch options are employed, additional metering and associated services such as data collection will require to be provided.

Sales

After any 'general awareness' activity has commenced, it is not expected that a DSR proposition will be engaged into by participants on a solely elective basis and a DNO will need to have skilled staff able to meet with site representative to discuss the proposition in detail. Based upon the extensive experience from the aggregators and Commercial Trials Lead (CTL) it is likely to require in excess of a single meeting and the ability to carry out negotiations in relation to arrangements, as well as lead any contractual dialogue in order to conclude and agree final terms.

Capacity Assessment

A capacity assessment is advisable to ensure that a site can realistically offer the capacity under negotiation. This is likely to require additional technical skills to review the generation installation and its current condition as well as any associated connection permissions for **T6**. Capacity associated with **T5** is more likely to require assessment by someone who has a knowledge of industrial processes to understand and verify the likelihood of their reliability as well as sizing the capacity. Both **T5** and **T6** capacity assessment will benefit from having access to at least 12 months of half hourly site consumption data which will also identify any variations relating to seasonal change. There are then many subtleties that require to be assessed particularly if for **T6** there are no full export permissions, or for **T5** there are process dependencies that would be impacted by DSR events. For this type of assessment it would be best to have a trained analysts to provide any conclusions on available capacity.

Training

In order to improve the performance of the sites and act as a reminder to the conditions associated with an appropriate DSR action, initial training for site operators will need to be carried out, as well as potentially offering an annual refresher if the DSR programme is to manage annual peak demand constraints. This could be of particular value to ensure that site operations have not altered over the preceding 12 months, affecting the anticipated capacity and commercial arrangement.

Commissioning

On most sites the existing metering will need to be supplemented so it can provide increased granularity from a calibrated device that can be remotely contacted and the data collected. Generators are likely to be able to offer the 1 min interval readings, but may present issues with accuracy of the reading to a recognisable standard, including calibrated clock and with the ability to access data. Despite DNOs having experience of metering, this would normally be settlement metering as opposed to direct connection to the output terminals of a generator which requires additional skills as well as specific method statements, permits to work and internal policies. These were all developed for WPD as part of **(S1)** and are now available for us within 'business as usual' if necessary.

Metering to measure a demand reduction site is similar to that of a standard settlement meter and will most likely be installed alongside the existing meter but still requires the additional granularity.

For the purposes of a trial the DSR services were dispatched manually by agreed communications method in order to avoid unnecessary cost and complexity. In **(S1)** this was by means of a phone call from the CTL 30 minutes in advance of the DSR event start time. Due to the change in approach for **(S2)**, and increased notice of the event dispatch it was possible to provide an email giving a schedule of operation that preceded dispatch by 7 to 12 days. This was more than adequate to support the service scope within the trials but should a more complex commercial offerings be developed where a DNO were to require real time visibility then significant technical enhancements would be necessary. If any automation or M2M integration is proposed, additional capability in this discipline will need to be developed or third party relationships established to meet the requisite.

Test

Once commissioned, it is necessary to ensure that all the components work correctly and that the participants will be able to meet the contracted reduction or generation capacity. As highlighted in the training requirement, it is probably advisable to repeat this part of the process annually to ensure that the capability of the site hasn't been negatively altered through general changes in their site infrastructure or processes during the elapsed period. This could be particularly prevalent with **T5** where any energy efficiency measures have been implemented since the last use of DSR.

Operate

The operation of commercial techniques will require similar enhancements for both direct and third party operation via an aggregator. To use the service for its intended purpose it is necessary to supplement the DNO control room with additional systems and policies to recognise where DSR capability has been introduced and the circumstances and mechanisms to dispatch it.

Post event, it will be incumbent on a DNO to have new systems in place that offer the facility to securely receive the performance data to assess and settle payments. Beta versions of back office software were developed for each season of the trials. These demonstrated the type of functionality that can now be further developed and scaled up to meet full enterprise software requirements if DSR is approved for BaU. More detail on this is available in section 10

Account Management

A very important aspect of the overall operation of commercial techniques will be the ongoing maintenance of the participant arrangements if it is expected that it is to be capable of being enduring. The role and responsibilities of an Account Management function are likely to be widespread and, as a front line representation of the DNO, it must be of a very high professional standard.

Account management will be, for most participants, the first point of contact for any DSR issues , but, due to the limited public engagement within the existing DNO business model it can be expected that it will become the focus of non-DSR related contact as well.

Within the specific requirements of the programme operation it is likely that the account management function will include:

- Primary contact for DSR related enquiries;

- Initial training and annual refresher training;
- Declarations of availability or issue reporting;
- Performance reviews;
- Billing and payment enquiries; and
- Contract or performance issues.

The following section details the experiences/learnings encountered in designing, implementing and operating the trials with engagement via aggregators.

8.2 Direct Engagement via Aggregators

What is an aggregator?

An aggregator, within the context of the UK Energy Industry, will generally be regarded as a service company that brings together the capability of many small sites, each with the ability to vary their consumption or embedded generation. Variations of this can also be referred to as a VPP (Virtual Power Plant), particularly in other international territories such as the United States.

This capability developed by the aggregator company is then used to participate in commercial programmes detailed in section 19.4, to derive an income that it then shares with its EPs (Energy Partners). In such applications, it is often advantageous to use aggregated demand side providers as an alternative to traditional power stations for a variety of reasons:

- Take advantage of existing infrastructure;
- Many small assets can respond more quickly than a traditional large power station;
- Large power stations require to burn large volumes of fuel to remain in a 'stand by' state;
- Distributed generation is less likely to be subject to single point of failure;
- Provides additional value opportunity to broad range of organisations, mostly out with energy industry.

At the time of **(S1)** there were a total of nineteen Demand Side Aggregators listed as UK service provider within National Grid's list of commercial service providers during the term of the trial. This is generally recognised to be a central register for businesses capable of aggregation wishing to offer services to others. It should be noted that there are also a small number of organisations that have developed aggregation capability in order to operate multiple small locations of their own.

- GDF SUEZ Energy UK
- Flexitricity

- Npower Ltd
- EnerNOC UK Ltd
- KiWi Power Ltd
- ESP Response Ltd
- Matrix – Sustainable Energy Efficiency
- Open Energi
- Endeco Technologies
- UK Power Reserve Ltd
- Tezla Energy Ltd
- EDF Energy
- Negawatt
- Cynergin Projects Ltd
- Energy Pool / Schneider Electric
- REstore
- Limejump Ltd
- Stor Generation Ltd
- Pearlstone Energy

The list has altered slightly throughout the two years of the operational trial phase, with a small number of providers having ceased and a similar number having joined during that time. It should be noted however that the barriers to becoming listed as an aggregator with National Grid is set relatively low and doesn't appear to be regularly audited. It therefore may be misleading as to the range of actual providers that are present within the market and can actually offer services. From the experiences of the trial and the lack of contact with a number of the listed provides it would appear that several of those listed do not actually provide ongoing services.

All of the listed parties at the time of the FALCON customer **(S1)** and **(S2)** acquisition plans being authored were invited to participate within the commercial trials. From this group there were positive responses from six for **(S1)** and **(S2)**, who wished to participate in the trials. All were proposing to either offer the inclusion of exiting EPs (Energy Partners) or attempting to acquire new ones within the trials zone.

The six aggregators listed alphabetically for **(S1)** were:

- Energy Pool
- Energy Services Partnership
- Flexitricity
- Kiwi Power
- Negawatt
- Npower.

The six aggregators listed alphabetically for **(S2)** were:

- Energy Services Partnership
- Flexitricity
- Kiwi Power
- Negawatt
- Npower.
- STOR Generation

For the remainder of the document the aggregators' identities will be anonymised and will be referred to by a reference name **(Ag1)** to **(Ag7)** to avoid any inappropriate disclosure of performance or other commercially sensitive information. Reference names have been allocated in no specific order but remain consistent throughout the report.

Each of the participating aggregators were provided with an aggregator briefing session and support document along with a copy of the newly developed DSR contract. Opportunities to discuss the scope, receive training or request any further support was made equally available to all aggregator companies. Additionally they were also requested to review and make any minor revisions to the contract in order that a single consolidated contract could be used across all companies. The details and outcomes of this process are dealt with separately in section 13. It should be noted however that due to issues over the completion of the contract and other issues relating to its core activities **(Ag7)** did not progress to be a participant within **(S1)** and made no attempt to enrol for **(S2)**.

8.3 Customer acquisition plan

Using both direct means and in association with aggregators, an acquisition plan was developed to recruit the range of sites necessary to complete the learning objectives, as detailed in the previous section.

The first stage of this was to identify a trial area with a defined geographical area in which the participants were required to be located. As part of the four technical intervention techniques, **T1-4**, WPD are working with a range of partners including Cisco, Alstom and Surf Telecoms to create an advanced communications network to support the project. The new WiMAX network provides low latency, high bandwidth communications to control the operation of **T1-4** and gather back critical performance data on their impact.

The network area defined by **T1-4** doesn't typically experience any substation overloading that would require intervention by the commercial techniques, **T5** and **T6**. In order to maximise the potential of the recruitment of the desired sites to test the commercial methods, the same substations selected for **T1-4** define the **T5** and **T6** trials area also.

The coloured area on the map below provides a general indication of the trials area.

This total area provides an extensive section of network containing a broad cross section of users from rural through to industrial and dense urban environments.

Table 2 - Trial area statistics

STATISTIC	VALUE
Approximate area	150 KM^2
Primary Substations	7
Secondary Substations	188
Overhead cables	Approximately 75km
Underground cables	Approximately 750km
Customer connections	Approximately 20,000

Figure 12 - Map of 'Commercial Trials' zone

The absence of real constraint problems requiring management also enables the trials to be operated but allowed to fail in the event of any complications, without causing disruption to customers. Additionally the network data being collected to establish the impact of DSR is less likely to be distorted by non-standard configurations of the network to manage BaU issues.

No specific restrictions were placed on any of the aggregators who were invited to adopt their own approach to EP acquisition and MWs would be allocated contracts on a first come, first serve basis. The outline requirements for the identification of participants were as detailed below.

Table 3 - S1 Trial Parameters for participants

Trial Service Parameters (S1)	
Total MWs in Trial	10 MW

Trial Service Parameters (S1)	
Number of Sites	10 – 15
Minimum Generation capacity Minimum Load Reduction	100 KW - (total target 9MW) 20KW – (total target 1MW)
Season	Winter (Nov’13 – Feb’15)
Contract Duration	2 years
Availability Time	16:00 – 20:00
Dispatch Notice	30 mins
Min Event Duration	1 hr
Max Event Duration	2 hrs
Maximum Total Hours (per annum)	40
Payment (utilisation only)	£300 per MWh

In order to satisfy some of the learning objectives, it was preferable that the trial would allow the comparison of different asset types and contractual / operational arrangements within the 10MW target. A diversity of generation types were sought to include both CHP and stand by assets, and both gas and diesel fuelled units. Load reduction sites were sought that would only include genuine response type sites that reduce based on an instruction, rather than daily pre-emptive reduction for cost management purposes. The trial however did not preclude ‘triad avoidance’ as an additional learning objective was to detail the synergies between triad management and DNO DSR requirements. The diversity of participants and generation types required are shown below:

Table 4 - Participant size classification

DR Method	Large	Medium	Small
Generation	> 1 MW	0.4 – 1 MW	< 400 KW
Load Reduction	>100 KW	25 – 100 KW	< 25 KW

The trial also sought to identify a minimum of two direct participants who had existing experience of DSR within another programme, as well as another who had no prior knowledge. The purpose of this was to gain a real comparison and assess the barriers to entry based on prior experiences.

In order to stimulate interest for direct participants, an external organisation NEF (National Energy Foundation) was recruited. NEF are an independent charity based in Milton Keynes, and have been at the forefront of improving the use of energy in buildings since 1988. Their stated aim is to give people, organisations and government the knowledge, support and inspiration they need to understand and improve the use of energy in buildings. NEF would provide an initial engagement through their local contact via direct knowledge sharing activities and attendances at a variety of local energy events and meetings.

Where any interest was generated through the general community engagement activities it was followed up by SGC (Smart Grid Consultancy Ltd) who designed and led the Commercial Trials for WPD. They have a team with detailed knowledge of the existing market mechanisms and expertise in aggregation ranging all the way back to its inception in 2007. SGC led the process to recruit participants, complete the engagement process, and carry out the commercial negotiations and final contracting arrangements for the commercial trials on behalf of WPD.

SGC also carried out post trials gap analysis to determine the differences between current DNO skills and capabilities and those that would require to be attained in order to operate a DSR service as part of BaU activity.

The following leaflet was created during the **(S1)** Design Phase of FALCON and was shared with potential participants:

Figure 13 - FALCON participant recruitment flyer

It was expected that the majority of participants would be sourced via aggregators and with multiple parties **(Ag1-6)** working across the same area, rather than being allocated their own territories. This enabled the project to allow greater freedom of approach and assess how each of the aggregators went about customer engagement.

Initial engagement processes were relatively diverse which was, to some extent influenced by their current core activities and maturity of the aggregators within the DSR environment. The more established companies were relatively quick to respond with the benefit of having existing sites located within the trials area. In addition, they also sought to influence some of their larger multi-sited Energy Partners who they already worked with, that had uncommissioned sites within the zone, to expedite the process to be available for the winter trial period.

Three of the six developed targeted campaigns to try and identify new capacity within the trials area. **(Ag5)** focussed its activity on their wide existing customer base, with whom DSR is a new capability, and sought to use this as an opportunity to introduce the new service capability on the back of FALCON. **(Ag6)** engaged with an external call centre organisation who procured a profiled customer list and attempted a campaign of cold calling to generate prospects. This was not solely for FALCON, and the value proposition being promoted was still primarily focussed on STOR and triad, with DNO revenues serving only as a small enhancement. However, the FALCON revenues were generally presented as 'guaranteed' which would not be the case in BaU, where it would only be accessed as necessary when constraints are likely.

Aggregators were provided with limited marketing materials from WPD to define the FALCON trials and were encouraged to present the importance and value of the trials in their own style and as part of their standard business development processes. A very simple process was then defined to offer a rapid approval route to confirm the status of any prospects and their participation within the trials as shown below. This was intended to serve as an opportunity to review the suitability of the site within the trial and to avoid the trials becoming over-subscribed.

Aggregator identifies existing or new site that can potentially participate

Aggregator notifies WPD of site location, DR method & expected capacity

WPD confirms availability of trial capacity or rejects from process

Aggregator submits 'site details' (see appendix A)

WPD carries out initial site screening based on 'site details'

WPD carries out detailed site screening based on site survey

WPD confirms or rejects FALCON participation

Figure 14 - Aggregator's participant recruitment process

Initial responses were very positive from **(Ag1)**, **(Ag2)** and **(Ag3)** all of whom had existing capacity located within the trials zone and early indications suggested that there would be at least six stand by diesel sites that would meet the three size requirement categories that we wished to include within the tests.

Direct activity by SGC with organisations with whom they had existing relationships also had very positive initial results with encouraging responses from;

8.3.1 Anglian Water (AW)

AW supply water and water recycling services to more than six million domestic and business customers in the east of England and Hartlepool.

The population they serve has grown by 20% in the last 20 years, but they still provide the same amount of water today as they did in 1990 – almost 1.2 billion litres every single day by minimizing leaks and encouraging more water-wise customers.

The huge region stretches from the Humber north of Grimsby, to the Thames estuary and then from Buckinghamshire to Lowestoft on the east coast with 112,833 km of water and sewer pipes. They supply and transport water across an area of 27,500 square km.

AW are the largest water and water recycling company in England and Wales by geographic area as well as one of the driest regions in the country, with just 600 millimetres of rain each year, on average a third less than the rest of England.

Compared with other water authorities, large parts of AW's region are typically flat and low-lying. The Fens of Cambridgeshire and the Norfolk Broads are just some of the stunning landscapes within the AW region, in a part of the world where approximately a quarter of the land is actually below sea level. This requires AW to be aware of the risk of flooding and with few hills to help out with gravity feeding they have to rely on pumping water from place to place which uses very high volumes of energy.

In order to provide security of water supply, AW require to own and operate a sizable fleet of emergency generation so that they can continue to provide water in the event of disruption to mains supplies. Many of these are already contracted directly to National Grid for STOR as well as for triad avoidance activity.

8.3.2 Thameswey Central Milton Keynes Limited

Thameswey Energy

In 2007, TCMK was set up as a subsidiary of Thameswey Energy Limited and owns and operates an Energy Station in Central Milton Keynes. TCMK was established to build and operate a Combined Heat and Power station to deliver district heating and a private wire network in the central business district in Milton Keynes.

The Energy Station is located in Central Milton Keynes and the heart of the station are two CHP units that are fuelled by natural gas with a combined an electrical output of 6.4 MW. The station supplies electricity and heat, via a district-heating and private wire network to The Hub, (a development comprising hotels, apartments and offices), Vizion, (a development comprising apartments, commercial outlets and a large Sainburys store) and The Pinnacle (the largest office development in Milton Keynes). It also has the capacity to supply electricity and heat to a proposed new residential area in the west end of Central Milton Keynes. The area served currently has a radius of some 1.5 km.

In 2010, TCMK generated more than 14 Gigawatt hours (GWh) of low carbon electricity and 12 GWh of heat from its Energy Stations. That's enough to provide electricity and heat to over 2,900 households. TCMK now has over 1,100 business and domestic customers who purchase their electricity and heat from our energy station.

With a high level of efficiency, TCMK can meet most of its customer's requirement with just one of the two generating units. This then provides TCMK with headroom capacity and an opportunity to use the remaining generation within DSR programmes.

Direct activity also identified a small number of opportunities to engage with companies who had little or no experience of DSR and would need a more thorough process to assist them on their technical suitability and business case assessment.

Direct activity also identified a small number of opportunities to engage with companies who had little or no experience of DSR and would need a more thorough process to assist them on their technical suitability and business case assessment.

8.3.3 Stadium:MK

The Stadium is a state of the art, purpose built venue that contains a 32,000 seated football ground, hotel, conference facility and new 3,420m² arena. The stadium was officially opened on 29 November 2007 by the Queen.

MK Dons' football ground, '*Stadium:mk*' became the focus of the activity, who had an emergency generator that had no permissions to operate in synchronous with the distribution network. Discussions were already underway with the stadium management team with regards to the siting of additional network assets to support engineering trials.

A series of meetings and an analysis of the site engineering requirements were carried out in order to provide an outline proposal including capital conversion costs and estimated annual running costs vs income.

The capital costs necessary for the 400kw generator needed to include conversions of the switchgear, controls and connection permissions. As the site only had consistent daytime loads of less than 200kw it was necessary to seek a permit to remain fully synchronised and export excess power back to the distribution network. This would result in an expenditure of more than £20K to set up and annual fuel cost in the region of £6,000 – 6,600 in order to receive an income of around £20,000.

In order to achieve this level of return on the initial investment the approximate benefit of multiple opportunities were included:

- STOR

- Triad avoidance
- DUoS avoidance
- Electricity commodity
- FALCON

A critical factor in being able to achieve the income is being able to access the revenue from STOR is the ability to be aggregated within a group that meets the minimum 3MW contract threshold. This is not currently within the capabilities of a DNO and therefore to pursue any further the stadium would require to engage with one of the aggregators working within the FALCON trial.

At this stage *Stadium:mk* reviewed the available information and declined to proceed further on the basis that they already had a very high workload and were at advanced stages of a large engineering project to extend the Stadium facilities as part of its core development strategy.

For further information on the site assessment and valuation of DSR services please see section 19.8 within Appendixes.

8.4 Participant Recruitment Parameters (S2)

Following the results of the **(S1)** trial being collected and assessed against the desired performance outcomes and general developments within the industry a number of key variations were identified for **(S2).** These changes have been detailed along with narrative explaining the reasoning behind each in the **(S1)** trials results, and 'Change Request' in section 18.

The tables below outline the recruitment requirement for **(S2)**. The generator volume requirements remained unchanged and as adequate volumes were secured in **(S1)** the sites were approached to confirm that they would be happy to continue their participation, despite a number of changes to the operational parameters. A generally positive response meant it was unnecessary to recruit any further generation capacity for **(S2)**.

The main focus of **(S2)** recruitment was in relation to Load Reduction. As part of the feedback analysis it was claimed by a number of interviewees that the level of incentive was a primary factor in failure to secure any capacity for the **(S1)** trials. A change request was therefore approved to 'roll-over' the unused **T5** payments budget from **(S1)** to double the payments for **(S2)**.

Table 5 - S2 Trial Parameters for participants

Trial Service Parameters (S2)	
Total MWs in Trial	10 MW
Number of Sites	10 – 15
Minimum Generation capacity Minimum Load Reduction	**(S1)** Participants retained no further capacity necessary. 20KW – (total target 1MW)
Season	Winter (Nov'14– Feb'15)
Contract Duration	1 year
Availability Time	16:00 – 20:00
Dispatch Notice	7 – 12 days
Min Event Duration	1 hr
Max Event Duration	2 hrs
Maximum Total Hours (per annum)	40
Payment (utilisation only)	£300 per MWh (generation) £600 per MWh (Load Reduction)

The following section details the processes differences between recruitment for the two commercial techniques.

8.4.1 T5 – Load Reduction

There are necessary differences between the profiling, targeting and acquisition of participants for **T5** and **T6**. Similar findings have been determined in general across the DSR industry which continues to be dominated by generation rather than load reduction. Despite this, there continues to be a general dialogue within stakeholder groups that load reduction service should be easier than as well as greener than generation and the focus of any strategies to grow capacity for DSR programmes. This is also particularly interesting for consideration of areas outside the FALCON commercial trials scope. Specifically, the future extrapolation of any FALCON results to assess the value of domestic DSR which will undoubtedly be heavily biased to energy reductions rather than generation.

If generation and load reduction are valued at the same price by the DSR programme it is likely that the bias will still be to generation. The underpinning factor in this is the financial return versus the cost of acquisition and operation. Identifying sites that may be able to participate is potentially more difficult, although it can be accepted that they may be more plentiful. In order to identify it is unlikely that they will have clear identifiable factors that can be the case with generation. Generators can have physical evidence such as the presence of exhausts, connection agreements with the DNO or relationships with the generator sales and maintenance organisations. Load reduction prospects do not tend to have obvious signs that act as a compatibility indicator, other than an assumption that the greater the total load, the increased likelihood of a portion being flexible. However, it should not be assumed that if a site has high loads, that any flexibility will exist at the periods where DSR is desired. It can therefore be expected that a cold contact mechanism will be necessary to engage with prospective sites in locations that will provide the appropriate impact. This will require skilled sales type resources who can establish a dialogue to commence any subsequent recruitment process.

The process outlined is multi-stage and will require a well-trained and professional individual to manage. As well as someone to lead the process, the range of skills necessary to complete the activity will require multiple visits by appropriate skilled representatives. This is broadly the process that was used within FALCON, with none of the prospect sites progressing beyond contract completion to the site commissioning stage in **(S1)** and only one in **(S2)**.

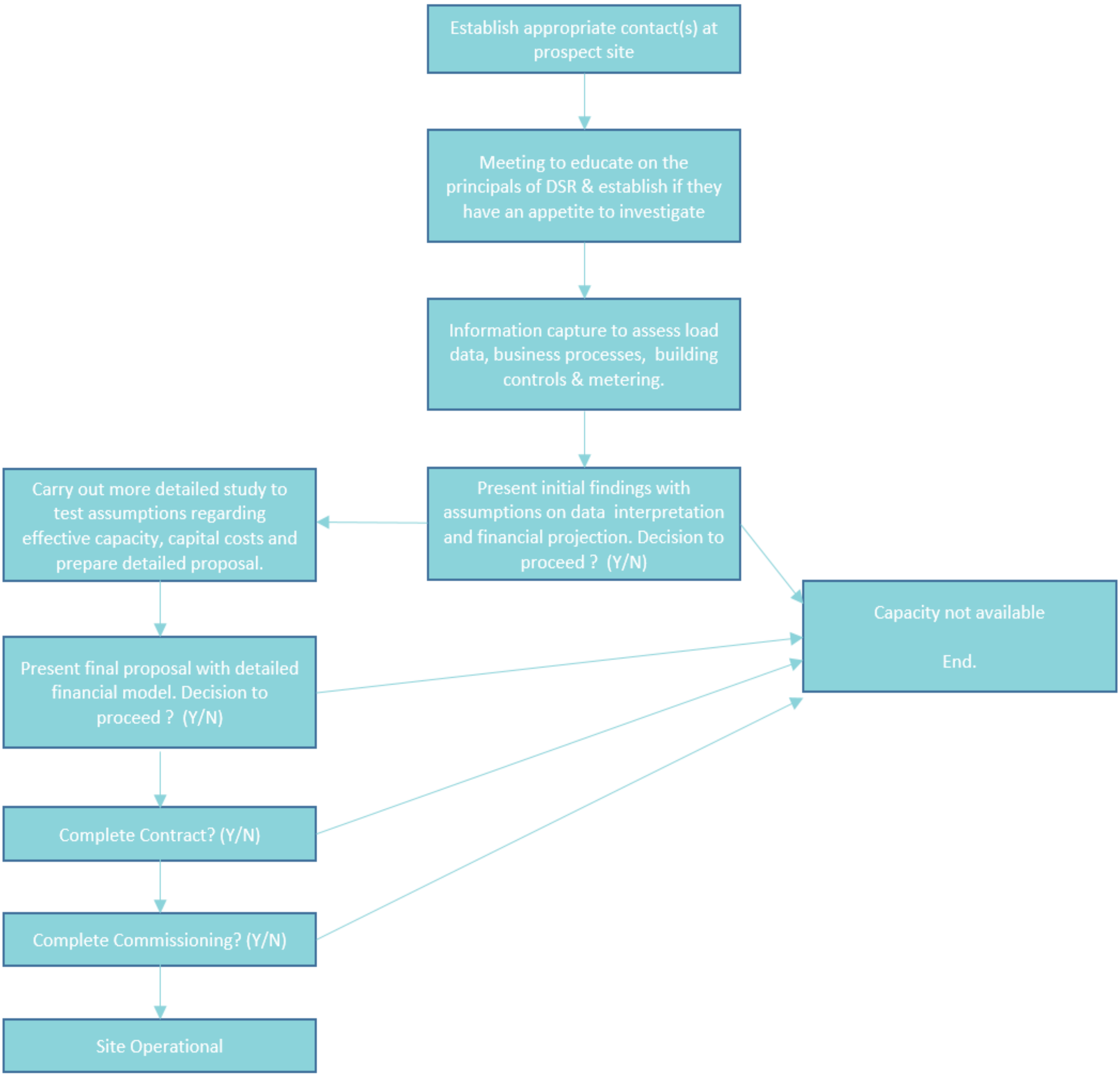

Figure 15 - Aggregator's participant recruitment process for Load Reduction

No ownership of the process has been determined in the diagram above. This could be carried out internally by new resources within a DNO or in conjunction with, or entirely by a third party aggregator. The cost of operating this process is likely to be borne by the process owner and needs to be considered as part of the overall cost to operate DSR, over and above the customer payments when operational.

As stated in the previous section, in order to access all revenues it may be necessary to be aggregated with other sites to achieve minimum contractual capacities.

As previously documented, the **(S1)** trials did not successfully acquire any 'true' load reduction sites. A number of the smaller sites that had generation were metered at the site settlement point. As the effect of this was to net off some of the total site load, the back office systems recognised this as Load Reduction. This at least enabled the trial to test the back office systems against the **T5** requirements but did not qualify towards the majority of load reduction learning objectives.

In general, load reduction sites are representative of having much smaller reliable capacity. It is difficult to determine an accurate statistic as to the difference between the average capacities of DSR participants offering **T5** versus **T6**. Based on industry knowledge and observations however, it could potentially be by as much as a factor of 10+. With such commercial conditions it is understandable why any organisation seeking to benefit financially are less likely to use load reduction. For an aggregator the cost of acquisition of a **T5** energy partner is likely to be similar or greater than that of T6 based on a site by site basis. If however it yields only 10% of the capacity then the economic proposition is vastly different.

There are additional compelling factors that act in conjunction with the lower average capacity to further explain the difficulty with acquiring **T5** participants:

- Difficulty identifying prospects;
- Complex / slow sales process;
- Less certain reliability long term;
- Can be in conflict with energy efficiency measures;
- Inadequate incentive to attract participants;
- Service operation can be complex depending on processes associated with reduction;
- Electricity supplier interest in existing load profile and future DSR potential may conflict DNO use case; and
- Final decision accountability.

Only a small number of serious prospects were developed during the course of the **(S1)** trial, and these required to extend beyond the time period initially defined as the 'EP Acquisition' phase. In total the deadline was pushed back a on three separate occasions with a final shortened duration '**T5** only' trial being proposed for April 2014. Despite every effort and with no remaining opportunity to reschedule again the **(S1)** load reduction trial was abandoned due to lack of participants.

Three separate aggregators had attempted to secure three different Energy Partners in **(S1)**, two of which are broader stakeholders with prior interest in Project FALCON. They can all generally be summed up as to have been unsuccessful due to a combination of the factors listed above.

The results of **(S2)** were not significantly different despite the changes to the programme's operational parameters, providing participants with increased notice of DSR events and doubling their incentive payment in relation to generation and **(S1)** Load Reduction.

Aggregators were invited to go back out to the market as a whole in a bid to find new potential prospects with very limited results. The majority of the aggregator led recruitment continued to focus on *The Open University* and *Milton Keynes Council* both of which had been the key target participants from **(S1)**.

Milton Keynes Council failed to demonstrate any significant progress throughout the recruitment phase and as with **(S1)** did not progress beyond 'initial discussions' phase. *The Open University* was from external observation more promising with the aggregator responsible for negotiating their involvement confident enough to sign a contract and forecast the site to be ready for the commencement of the operational phase. Despite this the site commissioning was never commenced and the site was declared unavailable for every week of **(S2)**. Due to the site never having commenced beyond this stage we did not include the declarations within the reliability statistics as this would result in a misleading bias to the final **(S2)** reliability results. It does however raise very valid concerns as to whether a guarantee should be sought from a participant or aggregator to ensure that they comply with the timescales that are set out by a DNOs operational requirements. The CTL did maintain weekly calls and correspondence with the aggregator and monthly meetings to determine progress. During the meetings there were repeated offers of assistance to help address issues that were preventing the site from progressing but these were largely internal issues with the aggregator's own sales and commissioning processes being inadequate and out with the scope of the trial to help resolve.

Greater success was achieved by direct engagement from WPD with the **(S1)** direct engagement partner *Anglian Water*. Following the successful completion of **(S1)**, a debrief was carried out and general discussion took place around the FALCON results, proposed changes for **(S2)** and general developments within the DSR market. Based on that dialogue, AW provided Half Hourly data for one of its water pumping booster sites located within the trials area. It was also apparent from the general market discussions that AW already recognised that there was a developing business case driven by time of day cost variations from suppliers and DUoS where FALCON DSR trials could be compatible. One of the key parameters in making the site viable was the latency associated with water pumping that meant it could potentially shift this activity to other times of the day. This is only feasible due to the site having bulk storage and pumps that exceed the underlying water demand.

On that basis it was possible for AWs, with the increased advance notice in **(S2)** to ensure that they had pumped adequate volumes of water in advance to allow the site to deliver reasonable reliability in meeting their DSR events schedules

8.4.2 T6 – Distributed Generation – (S1) only

The typically larger capacities that can be identified with generation sites generally make it the preferred option for aggregators and direct service provider as the means by which to operate DSR services.

Although the rewards are generally greater when compared with the small capacities associated with **T5**, generation sites can have several aspects that can complicate their recruitment. The trials have however clearly determined that these are more readily overcome than the difficulties securing the involvement of load reduction sites.

Aggregators were responsible for recruiting the majority of the sites that participated in **(S1)** and several of these were existing customers which expedited the process of acquiring capacity. This may not be the case if a BaU requirement occurs and will be largely dependent on where the constraint exists in the network and whether existing participants are located within a targeted 11kV (188) sub-station. However for a zone as large as the trial area this created a situation where almost the majority of 10MW trial capacity being sought could be quickly provided by sites that apparently already had the correct technical capability as well as some operational experience.

It was the case however that more than one major site had no prior DSR experience and due to a recent change of generation or historic issues relating to site approvals. This coupled with the experience at *Stadium:mk* enabled the trial to establish a similarities with the complexities of **T5**.

It should however be noted that despite some issues, in theory is should be easier for a DNO to attempt to identify potential participating sites by external indicators. In many cases a DNO could have a record of the generation located within the network. This may be because of existing synchronising permissions, prior application for synchronisation or physical evidence that can be observed such as exhaust stack or container enclosure. A DNO will therefore be best placed to develop a working record of generation sites located within their respective franchises. Currently out of scope from Project FALCON, but offered as a recommendation, is the opportunity for the industry to revise the connections application process. This could create the opportunity develop a comprehensive register of applications and granted connections when any distribution connected site seek permission to synchronise. This could dramatically simplify the process of acquiring **T6** participation. Thereafter where a DSR requirement is identified by planners, the time and cost associated with locating and establishing a dialogue would be significantly reduced. Additionally if a site did not pursue the connection permission, particularly where this was due to capital expense, alternative connection policies could be developed, offsetting capital charges against DSR service delivery.

In the event that these recommendations are accepted, a potential future project has been proposed as a follow on to Project FALCON. This would be to develop a new internal database of all legacy generation within the network, including any past and all future connection applications, regardless of its final status of acceptance. This should be combined with other objectives, including consolidation of all generation to the latest G59-3 standards and procedures to identify off-grid generation that has never attempted to obtain a connection.

The process within **(S1)** to recruit **T6** participants is outlined below. As with **T5** it is multi-stage and will typically require a well-trained and professional individual to manage. As well as someone to lead the process, the range of skills necessary to complete the activity will require multiple visits by appropriate skilled representatives

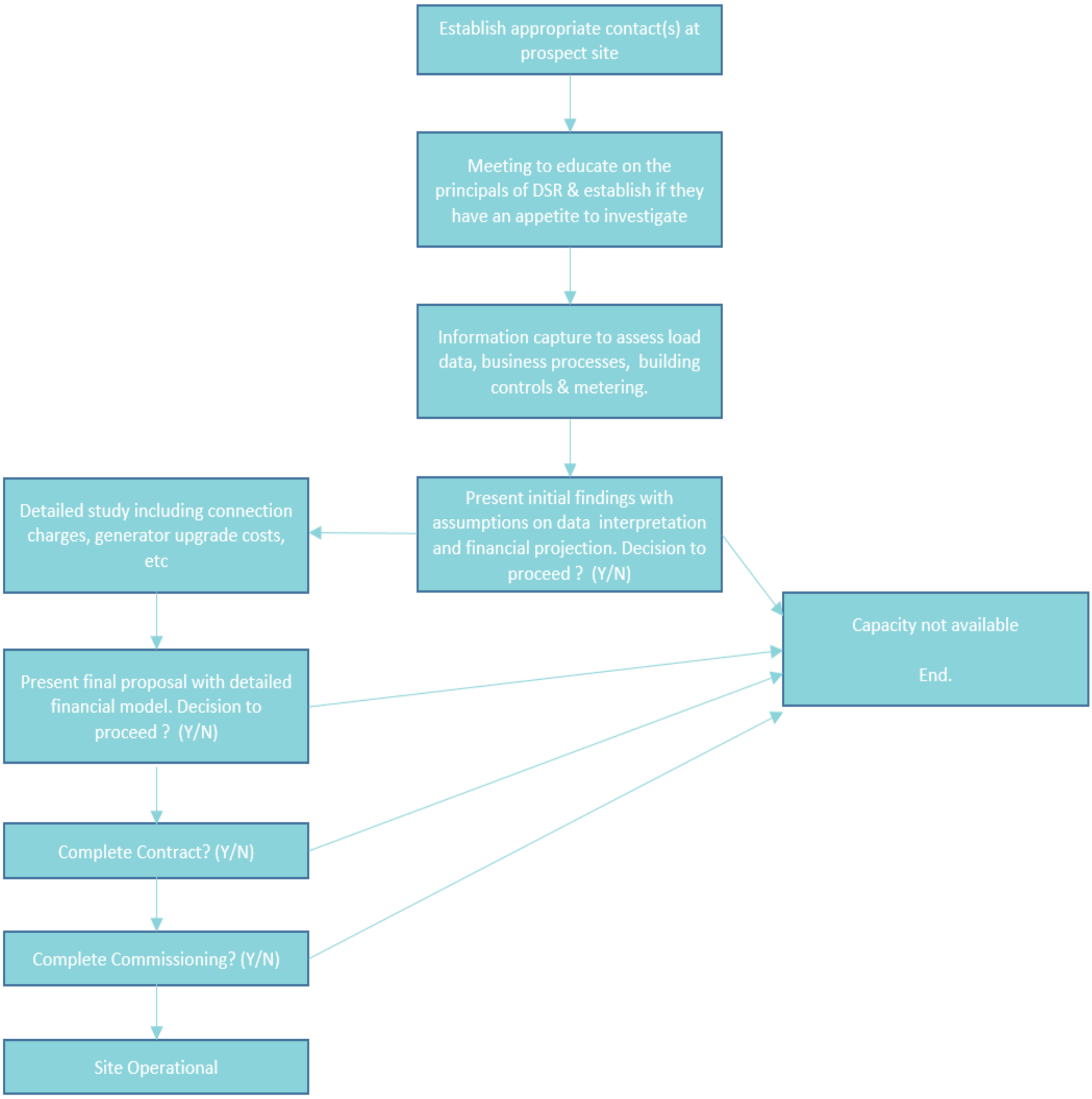

Figure 16 - Aggregator's participant recruitment process for Distributed Generation

As with **T5** Load Reduction, no ownership of the process has been determined in the diagram above. This could be carried out internally by new resources within a DNO or in conjunction with, or entirely by a third party aggregator. The cost of operating this process is likely to be borne by the process owner and needs to be considered as part of the overall cost to operate DSR, over and above the customer payments when operational. Again, similar to **T5**, in order to access all revenues it may be necessary to be aggregated with other sites to achieve minimum contractual capacities. However, it is more likely with generation to find a small number of sites which can meet the minimum capacity thresholds for direct participation in DSR programmes including STOR.

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Within **(S1)** trials we managed to contract representation for all of the variations of DSR sites that were initially set out in the commercial trials scope, as outlined in the table below. This was a very significant success in terms of being able to test learning outcomes but is inconclusive with reference to the likelihood of being able to locate and recruit generation in the correct location in a BaU scenario.

Table 6: Participating assets by size and type

	Diesel		Gas	
	Direct	Aggregated	Direct	Aggregated
Small (<400kw)	-	5	-	-
Medium (400 – 999kw)	1	4	-	-
Large (>1000kw)	-	1	-	1

SECTION 9

DSR Event Control

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The control room is the heart of operational management of the network where skilled WPD network management engineers monitor the network status and take actions to enable planned outages for maintenance as well as any other active operation to optimise its operation. For the trial, the control room were fully consulted at all stages of its development including design and build through to the event operations.

It is most likely that if a DNO opts to develop future DSR capabilities that although new resources will be required to establish the service capability, the owner and user will be the network engineers within the Control Room. As previously highlighted within the report, the Milton Keynes area of WPD's network is not subject to any serious constraints or seasonal overloading. Therefore the role of the control room within the trials does not require to include real operational decisions where commercial techniques would be necessary in assisting with the network operation. This has enabled the trials to be carried out in an impartial manner, where no favour has been given to any participants' location(s) and actual reliability could be tested by allowing sites to fail without risk to customer supplies.

In addition it was not necessary to test the methods and create suitable policies that will require to be developed in relation to when it is most appropriate to use DSR. This also enables the most suitable / effective dispatch mechanism(s) to also be left out of scope. Various other DSR programmes in the UK, and further afield, have already demonstrated there are many options ranging from very simple and low cost manual dispatch through direct contact (phone, text, email) to complex M2M systems that require no intervention in both the decision to dispatch event management. An advanced system such as this was developed in conjunction with the UK aggregator Flexitricity, as part of the 'Seasonal Generation' LCNF project in 2012. It was therefore deemed unnecessary to incur the expense of repeating such learning outcomes within FALCON.

The control room's role in the trials was largely limited to keeping them involved with any likely 'use case' or 'policy' development with regards to design and outcomes as well as liaising with during the trials to ensure that the trials did not create any negative impacts. A full briefing session on the Commercial Trials and the broader purpose of FALCON was carried out at a meeting of the Control Room shift managers and a Project Champion was nominated as primary liaison. As part of this role a general briefing was provided as key milestones were achieved.

It was determined that for the trials the control room would not be required to dispatch the events directly and the Commercial Trials Lead would carry out this function. It would, however, be necessary for the Control Room to be briefed ahead of every event so that the network state and configuration could assessed and ensure that the trials would not contribute to any negative impact on the network. An agreement was therefore put in place to commence the **(S1)** daily event trials process with a call to the duty team leader to obtain permissions to operate.

Due to the extended notice periods with **(S2)** the process was simplified by providing the Control Room with an email notification with the same 7 to 12 day advance schedule that was provided to participants.

In both instances the Control Room were provided direct contact details to the CTL who would remain on duty throughout the DSR events. This was in case of problems with either if a participant had any delivery issues or if for critical operational reasons the control room required the generation to be ceased. Over the two seasons there were only a few instances when it was necessary for this facility to be used by either party. Examples of the unusual circumstances that brought these about are listed below.

- Control Room had a major incident with the loss of supply from National Grid to a Grid Supply Point and were unable to complete pre-trial network checks due to overwhelming workload to resolve issues.
- Loss of generator at a participant site due to mechanical breakdown.
- Loss of metering connection to generator so unable to validate output for payment purposes.

SECTION 10

Back Office Systems

In order to operate the demand response programme it was necessary to determine the operational requirement and the payment calculations in a form that can be enclosed within the contract, as well as support the processing of back office assessment and payments.

Contained in section 10.1 and 10.2 are the calculations algorithms for seasons **(S1)** and **(S2)**. These were developed by Gary Swandells (CTL) and Iain Whiteside, a PHD student at Edinburgh University with significant experience of working within Demand Response programmes following a placement with the UK's first Aggregator. For **(S1)** this work was subsequently peer reviewed by Dr Alastair Martin. Alastair is a professional energy engineer with experience ranging from gigawatt-scale coal and nuclear power stations, through industrial energy efficiency, to very small embedded wind, solar and hydro generators. He founded the UK's first aggregated smart grid services provider and has extensive experience with payment calculations for DR services.

The main difference between (**S1**) and **(S2)** is the shift from short notice dispatch where the starting demand value against which performance is measured is dynamic and established at time of dispatch. The **(S2)** methodology adopted a capping mechanism due to the notice period being extended from 30 minutes to 7 to 12 days. The following section addresses the impact of the changes to the back office systems and associated resources. For details of why the change in methodology was necessary please see section 18

The **(S1)** an **(S2)** calculations are detailed in the remainder of this section.

10.1 (S1) Calculations

10.1.1 (S1) Assumptions

- A 24hr day is split into (24*60 = 1440) one minute segments. Time segment zero represents 00:00:00 to 00:00:59, segment 1 represents 00:01:00 to 00:01:59 etc.
- We write the site consumption (metered power reading) at the time segment i=0…1443 as C_i. We assume that the site consumption is measure in MW.
- Given a start time (ST) and finish time (FT) — written as time segments — we assume that the length of the DR event is inclusive of ST and FT. This means that the total number of segments in a call is **FT-ST+1**. For example ST=3,FT=10 is a DR event running through segments 3, 4, 5, 6, 7, 8, 9, 10 (a total of 8).
- We note that there are two separate cases for DR sites:
  - Sites that generate and thus **increase** generation in response to a DSR event.
  - Sites that consume and thus **reduce** consumption in response to a DSR event.

The meter value is treated differently in each case to calculate the **delivery**, which we write as D_i (at time segment i).

- The starting value against which performance will be monitored is AvC. Although this period is a variable, the default duration over which average is calculated is 5 minutes.

10.1.2 Payment Calculation / Generation delivery calculation

For a DR site that increases generation during a DR event, we calculate the delivery as:

$$D_i = \max[C_i - AvC, 0]$$

That is, at time i, the delivery is the current generation minus the average generation before the event. This value is compared with 0 and a maximum is taken to exclude the possibility that generation decreases during a DR event: we do not want to record negative delivery.

10.1.3 Consumption delivery calculation

For a DR site that reduces consumption, the opposite formula is required:

$$D_i = \max[AvC - C_i, 0]$$

Again, this means that, at time i, the delivery is the difference between the average and the current consumption. If consumption has been reduced during a DR event then this will be positive. If consumption increased, the maximum calculation caps it at 0.

10.1.4 Average delivery during a DR event

Given a DSR event with average demand figure AvC, start time ST, finish time FT, we calculate the average delivery as follows:

$$D_{avg} = \frac{\sum_{i=ST}^{FT} \min(D_i, CM)}{FT - ST + 1}$$

where CM is the contracted capacity in MW.

This formula sums the **capped delivery** (calculated as the minimum of the delivery and the contracted capacity) for each time segment in the DSR event then divides it by the number of segments in a DSR event. This gives an average delivery in MW.

Total delivery and payment value

Using the average delivery and the length of the DR event in hours, we can calculate the cumulative delivery in MWh as follows:

$$D = D_{avg} \times \left(\frac{FT - ST + 1}{60}\right)$$

Then, the payment is calculated from the price per MWh, which is set at £300:

$$Payment = D \times 300$$

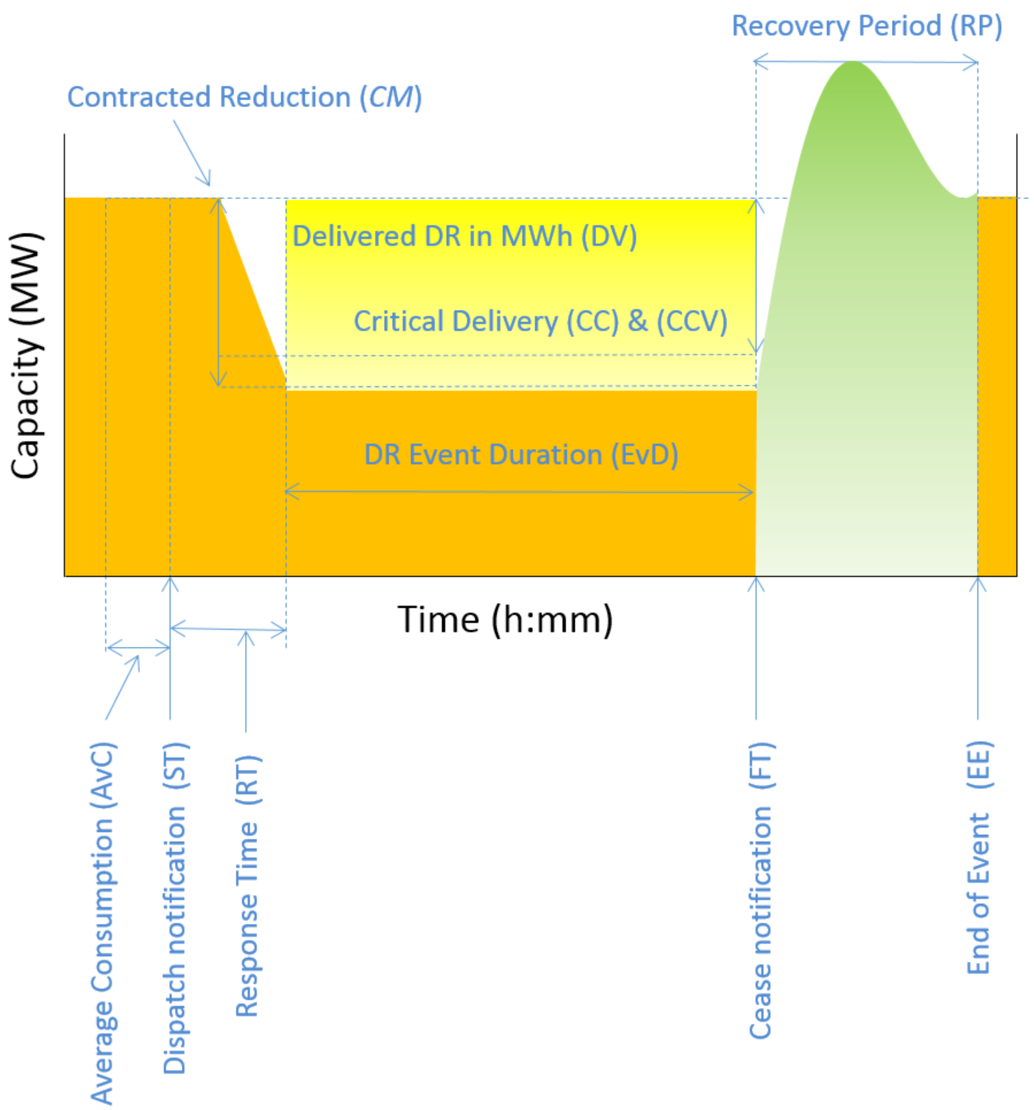


Figure 17- Diagram (A) – DR Measurement Schematic

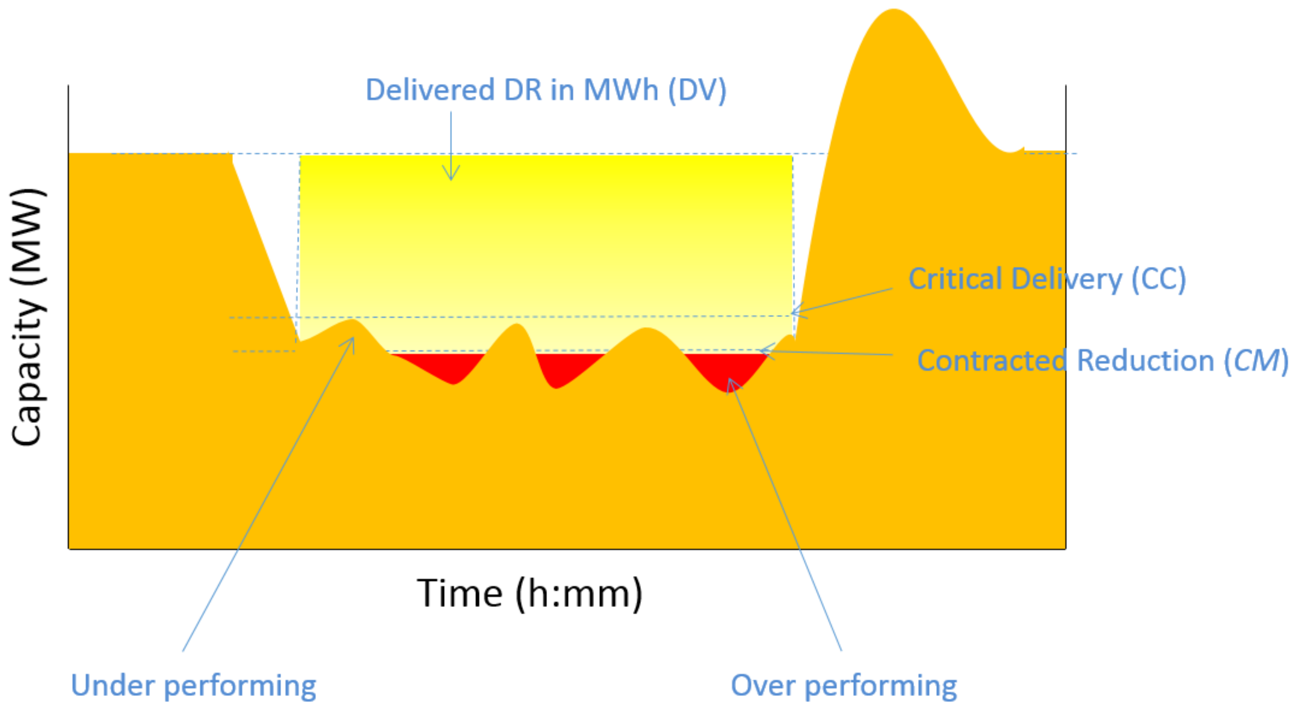


Figure 18 - Diagram (B) – DR Payment Schematic

10.2 (S2) Calculations

10.2.1 (S2) Overview

In this section, we detail the assumptions, variables, and formulae for accurate calculation of utilisation payments **(S2)** of the FALCON trial.

Delivery targets and payment has been revised from **(S1)** with the aim of improving accuracy of demand response events in three ways:

1. Instead of calculating *delivery* as a delta from the mean consumption before the DR event and consumption during the DR event, there will be a *fixed consumption target* that must be met for the entirety of the DR event. This fixed consumption target will be calculated *at the start of the year* based on a required drop from peak consumption.
2. DR events are planned in advance, rather than 'on the fly'.
3. Delivery that does not meet the target will be penalized on a minute-by-minute basis using a fixed *penalty factor*.

This section split into three parts.

Part 1, details the payment calculation itself;

`

Part 2 details the *event of default* flag detection predicate; finally,

Part 3 details how the previous year's peak can be calculated to generate a *consumption target*.

Due to the change in the method of monitoring the sites form **(S1)** the monitoring and calculation process is more complex and the point of measurement has shifted. In **(S1)** we were able to use the output metering of generators or sub metering to demonstrate the response at the point of delivery from the assets being used. However with the shift to a capping mechanism rather than delta change it is vital that we now monitor the impact at the point of connection / settlement to ensure that the entire site stays within the desired limits.

10.2.2 (S2) Assumptions

- We call the period of Demand Response a DR event.
- A 24hr day is split into (24*60 = 1440) one-minute segments. Time segment zero (T_0) represents 00:00:00 to 00:00:59, T_1 represents 00:01:00 to 00:01:59 etc.
- We write the site consumption (metered power reading) at the time segment *i=0…1339 as* C_i. We assume that the site consumption is measure in kW.
- Given a start time (ST) and finish time (FT) — written as time segments — we assume that the length of the DR event is inclusive of ST and FT. This means that the total number of segments in a DR event is **FT-ST+1**. For example ST=3,FT=10 is a DR event running through segments 3, 4, 5, 6, 7, 8, 9, 10 (a total of 8).
- We assume that DR events do not stretch over two calendar days i.e. the above calculation is sufficient.
- We note that there are two separate cases for DR sites:
- Sites that *generate* and thus **increase** generation in response to a DR event.
- Sites that *consume* and thus **reduce** consumption in response to a DR event.

In **(S1)** a different calculation was required for each, but in this case, we assume that *consumption* is the site's external consumption. That is, if a generator takes 1/3 of the site load, then the import from the grid becomes 2/3 the initial. Similarly, if equipment is turned off for a DR event, the import consumption will also decrease.

10.2.3 Variables

- The *Previous Peak (**PP**)* is the value in kW to which penalties and consumption targets are measured.
- The *Desired Delta (**DD**)* is the value in kW that is required for demand response. It can be compared to the contracted capacity of last year.

- The *consumption target (**CT**)* is defined as the difference between the desired delta and the previous peak:

$$PP - DD$$

Thus, if a site generator has a capacity of 3000kW, and the previous year's peak was 4000kW, then the consumption target will be 1000kW. [In order to develop an increase in overall reliability we have opted to test a generous calculation method, since, if site consumption stays similar to the previous year, it is unlikely that consumption will be at the peak]

$$CT = Max(PP - DD)$$

- The *Segment Payment (**SP**)* is the value in pounds for appropriate delivery in that segment.
- The *Penalty Factor (**PF**)* is given as a multiplier for deduction of payment *per percentage decrease in delivery against target.* The PF can be 1..100.
- The *Grace Period (**GP**)* is given as the *percentage decrease in delivery against target* that does not accrue financial penalty. The GP can be 0..100.

10.2.4 Payment Calculation

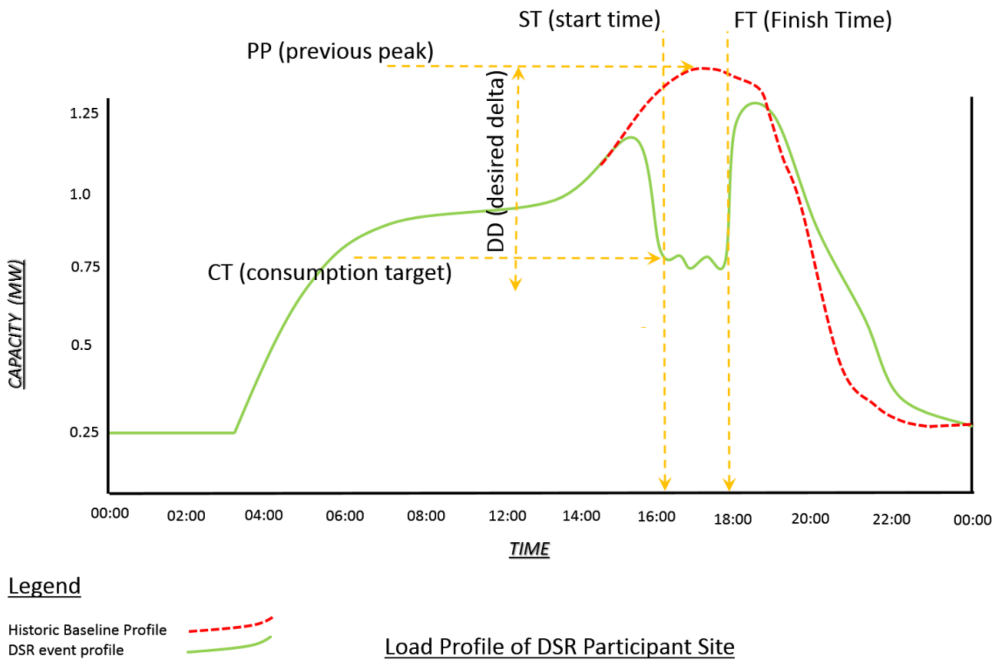


Figure 19 - Example daily consumption profile including DSR event

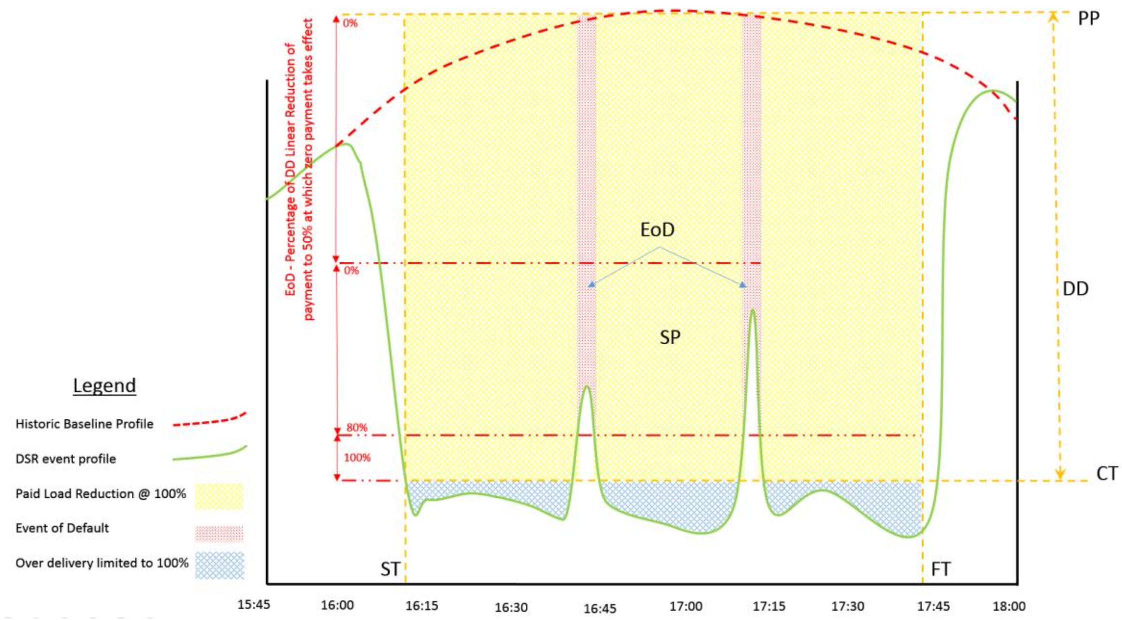


Figure 20 - Example detailed view of consumption during DSR event

The basic calculation for payment during a time segment T_i shall return a *payment multiplier (**PM**)*, which is a value between 0 and 1 that refers to the percentage (recall 0=0% and 1=100%, and to find the %, we multiply by 100) of payment that is due for that particular time segment.

If the current consumption is **less than** (or equal) to CT, then we pay the full amount. That is, PM=1. IF the current consumption is (strictly) **greater than** CT, then we need to calculate the factor by which it is under-delivering in order to calculate the appropriate penalty. Rather than separating these out into two calculations, we can combine it into one. First, we calculate *target difference (***TD**) as follows

$$TD_i = Max(C_i - CT, 0)$$

The target difference is the number of kW by which the site did **not** meet the target for a particular time segment (T_i). If the site did meet the target, TD will be zero, by virtue of the maximum function.

The fraction of the desired delta DD and the TD gives us the percentage by which a call has *Missed Target* (MT):

$$\frac{TD_i}{DD}$$

Example 1. A peak consumption of 10 and target consumption of 5 has a delta of 5. If the actual consumption at a particular time is 4, then the TD = Max(4-5,0)=Max(-1,0) = 0. Thus, the ration is 0, and since the delivery is correct, we have a 0% missed target as expected.

Example 2. A peak consumption of 10 and target consumption of 5 has a delta of 5. If the actual consumption at a particular time is 6, then the TD = Max(6-5,0)=Max(1,0) = 1. Then the MT is 1/5 = 0.2. Thus, for delivery that is a 4(kW) reduction from the peak, instead of the desired, we only supply 4/5 of the required DR; thus, we have a 20% MT.

Let us consider the ratio of TD_i and DD. The maximum that TD_i can be is C_i -CT. Now CT is PP-DD; thus, TD_i is C_i +DD-PP. This means that the ratio will be >1 only when C_i > PP. In these (presumably rare) cases, we wish to return a MT of 1. Thus, we modify the formula for MT to:

$$MT_i = Min(\frac{TD_i}{DD}, 1)$$

The minimum that TD_i can be is zero, since negative consumption is not allowed for a reduction and if a site is exporting we will measure a file with an export reading against a minimum value.

The grace factor (GP) is then applied to 'reset' the missed target to allow for the grace percentage before deductions are made, giving the grace-adjusted missed target (GMT):

$$GMT_i = Max(MT_i - GP, 0)$$

For a 10% GP (i.e. 0.1), our example 1 has still a value of 0 for missed target; example 2, however, now has a missed target of 0.1 i.e. 10% rather than 20%.

We are now in a position to calculate the payment amount by applying the penalty factor to get the payment multiplier:

$$PM_i = 1 - Min(PF \times GMT_i, 1)$$

Firstly, we multiply the missed target by the penalty factor to find the appropriate penalty. If the penalty exceeds 1, then we do not wish to pay anything, thus we cap to 1. Finally, the payment factor itself is the percentage not removed, so we use 1 – the penalty.

For the following examples, we assume a PF of 2.5. *(the trial will use a PF value of 2).* That is, payment is reduced by 2.5% per 1% loss of delivery. In this case a 40% missed target we get zero payment.

Example 1 *(ctd).*

For an MT of 0 and therefore GMT = 0, the payment multiplier is then 1-Min(2*0,1) = 1-0=1. Thus, we pay 100%.

Example 2 *(ctd).*

For the case when we deliver 4/5 DR and the MT is 0.2, with a 10% GP we have GMT = 0.1. Thus PFxMT=0.25, thus we only pay 75%.

Example 3*.*

As a final example, consider A target consumption of 5, DD also 5 (as above, thus peak is 10) and this time actual consumption is 9. Thus means that the target difference is 9-5=4. The MT is then 4/5 = 0.8 and, keeping the 10% GP, we have a GMT of 0.7. Then PFxGMT = 2.5*0.7= 1.75, which is then capped at 1. Thus, the payment multiplier is 1-1=0. That is, we pay nothing!

Finally, we define the payment at T_i as:

$$P_i = SP \times PM_i$$

We can then define the payment for the duration of a DR event E (with start time ST and finish time FT) as follows:

$$P_E = \sum_{i=ST}^{FT} P_i$$

For convenience, we repeat the individual formulae:

$$CT = Max(PP - DD)$$

$$TD_i = Max(C_i - CT, 0)$$

$$MT_i = Min(\frac{TD_i}{DD}, 1)$$

$$GMT_i = Max(MT_i - GP, 0)$$

$$PM_i = 1 - Min(PF \times MT_i, 1)$$

$$P_i = SP \times PM_i$$

$$P_E = \sum_{i=ST}^{FT} P_i$$

10.2.5 On Segment Payment Values

The segment payment value, SP, can be given as either a single, static value or it can be derived in the more traditional sense from a £/kWh based on the desired delta value.

For example, if a payment is 0.06 £/kWh and the desired delta is 5000kW, then for each segment (recall, 1 minute of time) the payment will be 0.06/60*5000 = £5 per segment i.e. per 5000kW delta per minute, the payment is £5.

Given a *DR Cost* (**DRC**) in £/kWh, then we define

$$SP = (DRC / 60) \times DD$$

We could also generalise this over arbitrary segment lengths if required.

10.2.6 Events of Default (EOD)

We wish to also flag the occasions during a DR event in which the delivery is under a certain 'event of default' range of, say, 90%. We specify how this flag can be set for a given time segment using a boolean range operator >= . We assume a flag of 1 is associated with TRUE (an event of default); and a flag of 0 is associated with FALSE (no event of default).

We write the *default percentage (**DP**)* as the percentage (represented as 0..1) of delivery **below which** will trigger an event of default. Then, given a consumption target CT, and desired delta DD, the *default limit (**DL**)* is then given as:

$$DL = CT + (DP \times DD)$$

For example, a consumption target of 4MW for a desired delta of 4MW with an EoD percentage of 10%=0.1, we have a default limit of 4.4.

The **EOD** at time segment *I*, $\mathbf{EOD_i}$ is then defined by:

$$EOD_i = DL \leq C_i$$

Thus, for the example above, an EOD will be flagged at a particular time segment if the consumption is greater than or equal to the default limit. A consumption of 4.8, for example, is 0.8MW short of the required delta and greater than 4.4 therefore this time segment will be flagged as an event of default.

10.2.7 Previous Peaks

There are many options for previous peak calculation. Given a year of consumption data, the *previous peak* could be calculated in various different ways. Let us refer to the days as 0…364 (or 0…365 in a leap year): January 1st is day 0, and December 31st is 364 (the 365th day). We then extend the consumption notation as $C_{i,j}$ to mean the consumption on day **i** at time segment **j**.

- PP 1

The most basic measure for the previous peak is the mean consumption at any segment on any day:

$$Mean[C_{i,j} \mid i = 0..364, j = 0..1339]$$

That is, the mean consumption ranging over every day and every segment. The syntax is that of a list comprehension: creating a list of all the consumption values for the range generated.

- PP 2

In the event that some days or time segments should not be considered, we can refine the above calculation. We assume a set of pairs of values (i,j) that are the *exceptions*, **E**:

$$Mean[C_{i,j} \mid i = 0..364, j = 0..1339, (i,j) \notin E]$$

As an alternative to the *mean*, a maximum or other calculation could also be applied.

Table 7 - Equation nomenclature

Name	Short	Min	Max	Units	Description
Previous Peak	**PP**	0	N/A	kW	The peak value from the previous season for which the delta is to be applied to calculate the desired consumption during an event.
Desired Delta	**DD**	0	N/A	kW	The amount of consumption (measure from PP) to be reduced during an event.
Segment Payment	**SP**	0	N/A	£/kW /min	The price per kW per segment.
Grace Period	**GP**	0	1	%	The % of delta less than 100% to not deduct cost.
Penalty Factor	**PF**	0	100	None	The factor to multiply a 1% difference from target and actual by to calculate reduced payment.
EoD Percentage	**DP**	0	1	%	The % of delta representing an event of default.

`

For the purposes of the trial and based on the lower than desired reliability in **(S1)** a simple method that involves the manual establishment of the 5 peak periods on 5 separate days will be employed and the average of this taken as a fixed value for PP throughout the events for all weeks. The final trials report will contain the range of options considered for establishing a PP value and potential rationale where they might support varying behavioural responses from participants.

10.3 Software – High Level Design

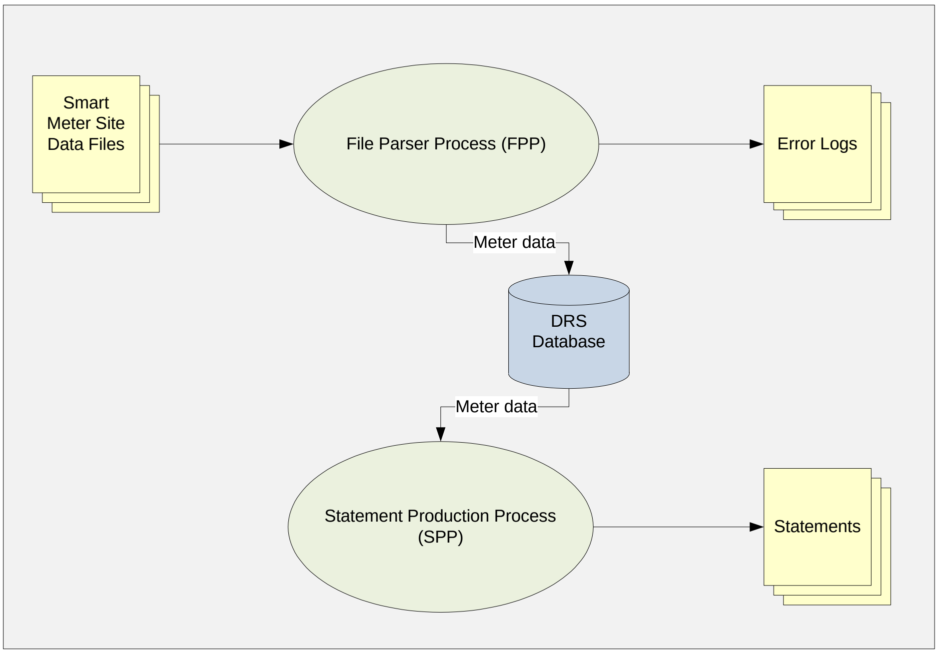


Figure 21 - Software, high level architecture

The File Parser Process (FPP) process will poll for Smart Meter Site Data (SMSD) files within a defined directory. File processing will follow one of three possible paths

File data not within the Demand Response Event Calendar and will be moved to a defined 'ARCHIVE' directory.

File data is within the Demand Response Event Calendar but has failed to be parsed due to data integrity rules. An appropriate error will be reported within a defined error file and the file will be moved to a defined 'ERROR' directory.

Fila date is within the Demand Response Event Calendar and has successfully passed all data integrity rules. The file will be moved to a defined 'ARCHIVE' directory and all data required from the input file for statement calculation and production purposes will be stored within the DRS database.

`

The process will be able to be manually run through a simple desktop icon. This allows the flexibility to run in the daily files as they are received or in bulk prior to producing the statements.

The Statement Production Process (SPP) Process is manually triggered. Once running the process provides the operator with a list of event dates for which event data is available. Once an event is selected the process displays all Clients associated to the event and asks for start confirmation. For each customer all related meter data within the Event will be processed according to pre-defined calculations and customer parameters regarding their performance during the DR event.   Performance data including a graphical image and payment data will be output to a readable customer statement in HTML/XML format within a defined 'OUTPUT' directory. This file will then be available for either print or email. A file will be produced per customer per event.

The DRS Database developed in open source Postgress will be used to hold relevant data retrieved for statement production. This consists of:

Standing data: Demand Response Event Calendar, System level parameters and Customer level parameters required for file identification and statement calculations

Meter Data: Customer specific Read Data retrieved from the input files and used for statement production

`

10.4 Payment Model options

The process of determining the calculations that we wanted to develop to manage the capping of site demand was not as straight forward as may initially be assumed as there are several ways that this can be achieved. This was ultimately reduced down to five options and the final option that was chosen and explained in the previous section (Section 10.2) . The method selected '*Model A'* was picked due to its perceived simplicity despite containing a relatively complex algorithm that presented participants with a grace period for mild underperformance then an escalation factor that reduced payments at double the rate of the prorated shortfall. All of the models contain scope for variability that allows the grace margins and penalty multipliers to be increased or decreased to help affect and incentivise the behavioural response to ensure maximum reliability.

The overall structure of each payment model considered were designed to have a greater impact on the nature of the delivery we were seeking to procure rather than variables within the payment calculation to fine tune the reliability. The following visualisation diagrams should help clarify the differences between '*Models B to E*' and what we considered would be the likely impact of their use.

10.4.1 Model B

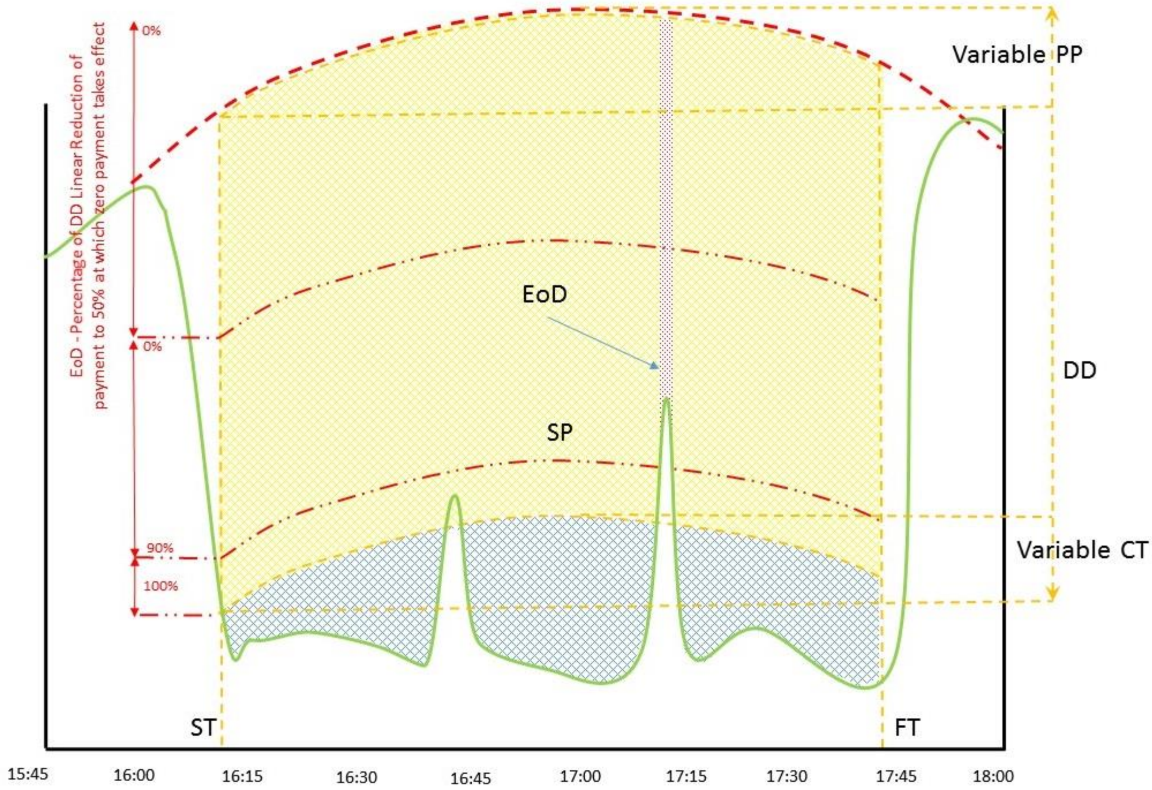


Figure 22 - Dynamic peak model

Model B utilises a Dynamic peak that follows the shape of the sites historic demand profile. The site therefore only has to maintain a reduction delta at a constant value and still allows for some rise and fall over in accordance with the historic profile. Under this regime the site would incur less of a penalty for the underperformance than it does with Model A as they have some allowable movement rather than a flat cap. The result is only a single EoD.

It would reduce the overall payment by reducing the potential over delivery of volume.

This would be of benefit where the constraint to be managed was relatively constant over the period and the DNO wished to avoid paying for unnecessary volumes.

10.4.2 Model C

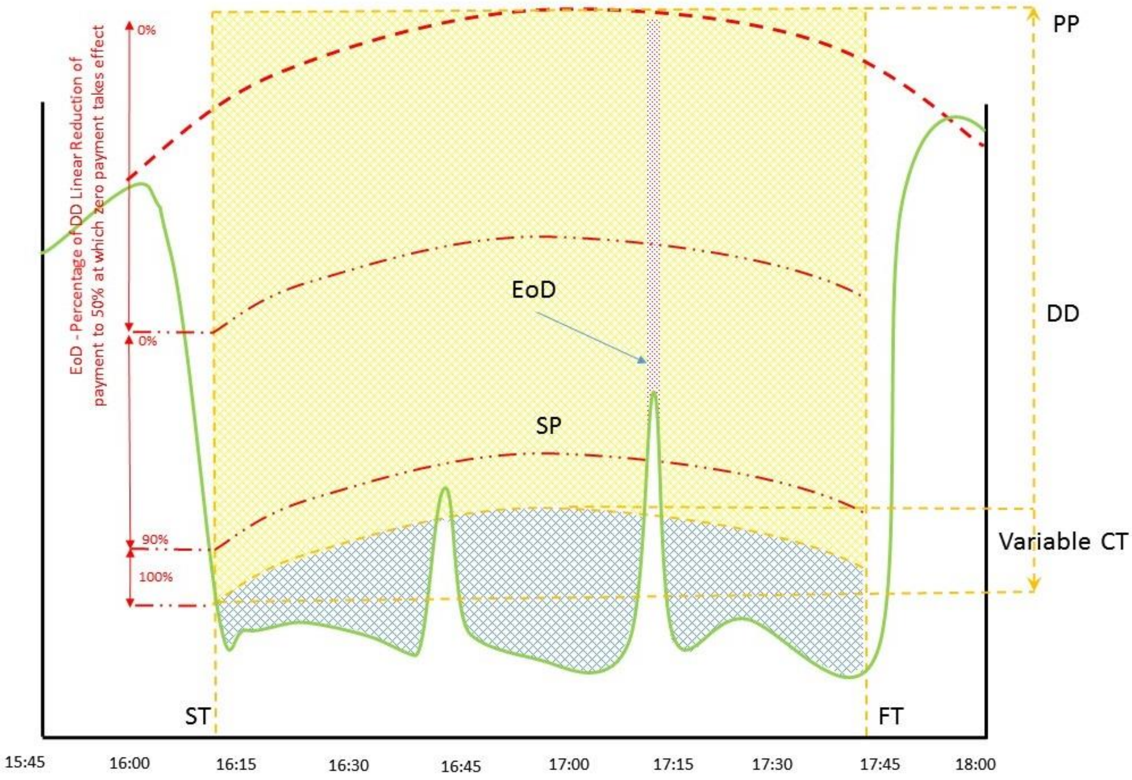


Figure 23 - Fixed peak model

Model C utilises a fixed peak that is set against the peak of the sites historic demand profile. The site therefore only has to maintain a reduction delta at a constant value and still allows for some rise and fall over in accordance with the historic profile. Under this regime the site would have the opportunity to over deliver to either side of the peak. As with Model B, it would also benefit from the less of a penalty for the underperformance than i Model A as they have some allowable movement rather than a flat cap. The result is only a single EoD.

This may be of benefit to a DNO when forward forecasting events by five days or more and there is some uncertainty of when the exact peak demand will occur. By encouraging over delivery the participants are more likely to extend the shoulders of the event to cover variance within the peak time or duration but reduce payment for over delivery of volume.

10.4.3 Model D

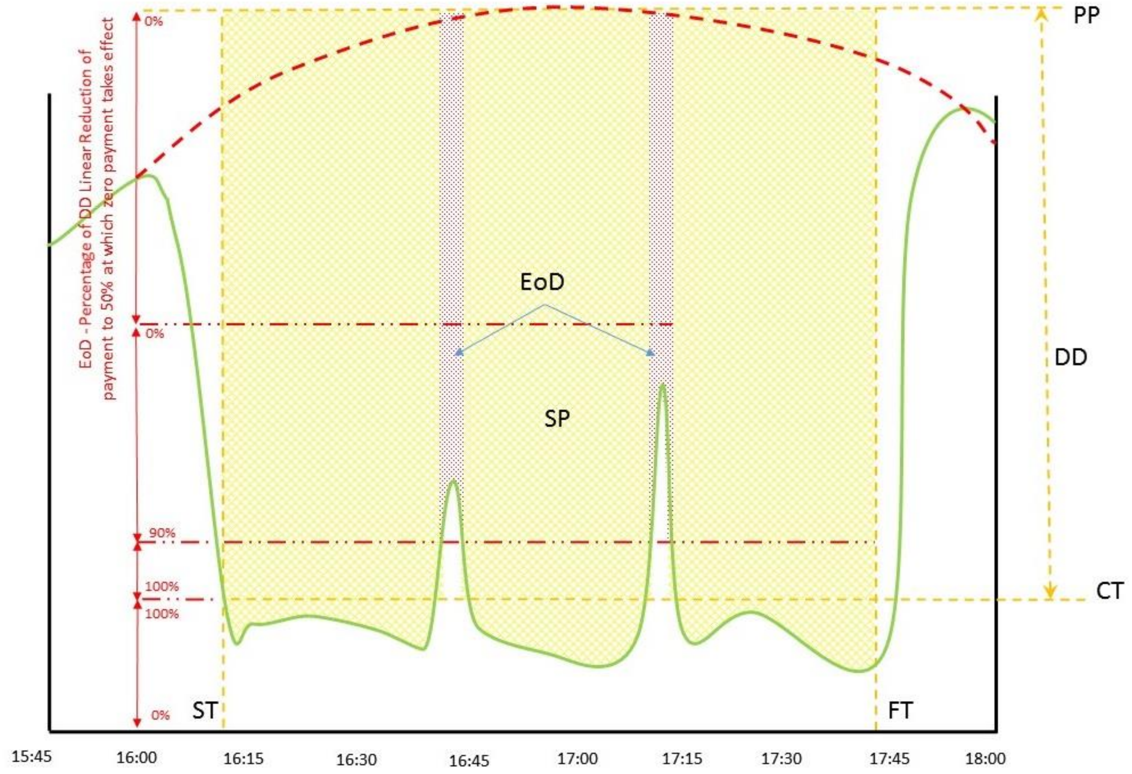


Figure 24 - Fixed peak, historic demand

Model D utilises a fixed peak that is set against the peak of the sites historic demand profile. Under this regime the site would have the opportunity to over deliver to either side of the peak as well as in overall volume terms above 100%. This method is encouraging as much response as possible but volumes above 100% are also subject to a reducing value that can be reduced pro-rata as its value to the network reduces. This scheme does however maintain a constant EoD trigger value with no penalty reduction in line with historic demand curve.

This may be of benefit to a DNO where the response desired is of higher risk or where there is direct correlation between the volume of reduction available and the value of lost load or constraint issue.

10.4.4 Model E

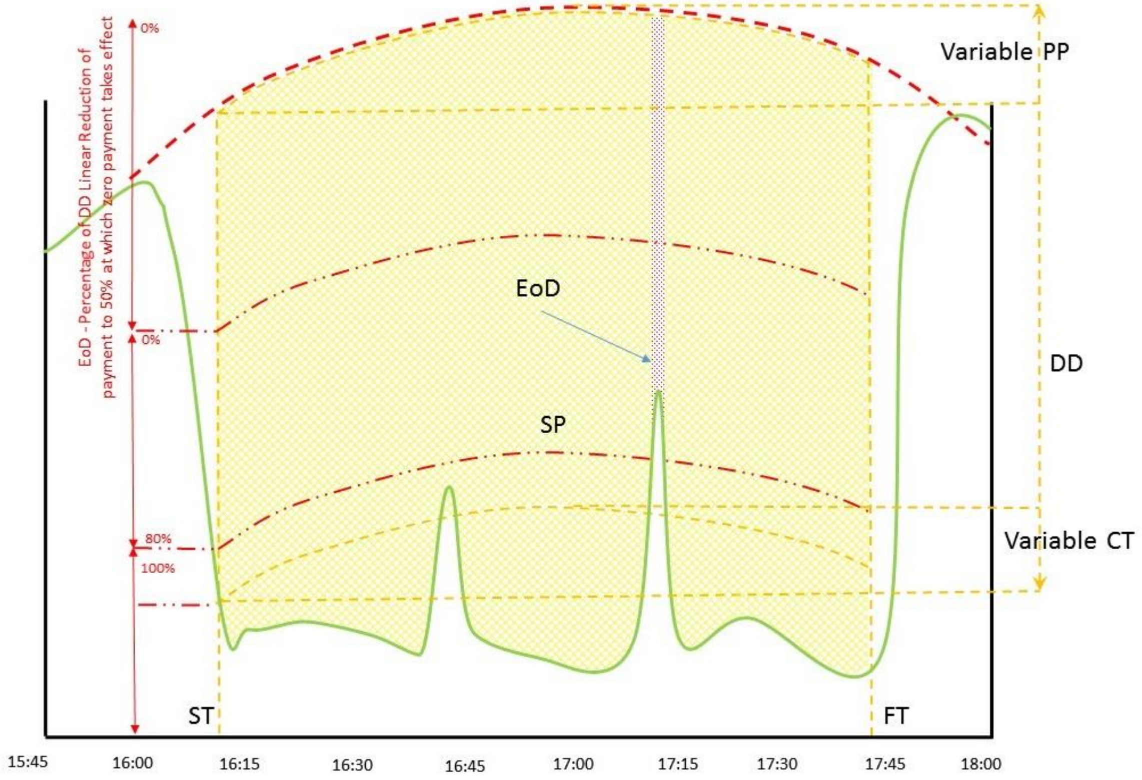


Figure 25 - Shaped peak

Model D utilises a shaped peak that is set against the sites historic demand profile. Under this regime the site would have the opportunity to over deliver but encouraged to do this around the predicted peak of where their own historic peak would have been. This method is encouraging as much response as possible as volumes above 100% continue to be paid at full rate. This scheme doesn't penalise as heavily for EoDs due to the historic demand curve.

This may be of benefit to a DNO where it requires as much capacity as it can incentivise but focussed around a short sharp peak period.

10.5 (S1) and (S2) Performance contract relationship

Within a BaU environment it is expected that the DNO will need to maintain ongoing relationships with the DSR provider, or an aggregator as an ongoing business activity. As a commercial service it cannot be assumed that, once a new DSR participant has completed the acquisition process (as outlined in section 8) and are declared operational, a 100%

performance will be achieved. There are many factors that could affect the potential reliability of a site, but through appropriate communications this may be influenced positively.

If DSR is not used regularly then it is likely to reduce in reliability, as outlined by some of the factors below:

- Change of energy usage at site, reducing flexibility or altering process time criticality;
- Change of management or operational staff and/or lack of training;
- Rarely tested generation is inherently unreliable;
- Limited familiarity with DSR process and expectations and
- Under investment in servicing and repairs.

In addition to the benefits of maintaining an ongoing relationship to ensure that the site conditions remain favourable to reliable performance, it is necessary to establish the function of account management. This will ensure that sites actively employed to provide DSR meet their targets and that payment processes follow as expected. If there are any deviations from the expected outcome for the DNO in the site performance, or for the site in relation to payment, this will require to be resolved by direct communications. This would probably initially be provided by phone based first line support, but it is also likely to require a face to face meeting in the event of any issues requiring to be escalated. Currently, there aren't any similar roles contained within the DNO business structure as normally any customer contact relates to fault reporting which passes to engineering, or new connections which are predominantly managed by a process of documentation.

In order for DSR to be a BaU activity, this would be one of the prime areas where a detailed gap analysis needs to be conducted in order to define the extent of cultural change and new skills development. In the event that a DNO develops a service model that seeks to operate directly with participants it is likely that the challenge of developing such new capabilities will be significantly greater than if third party aggregators are employed. The requirement is not fully negated by outsourcing the DSR acquisition and operational functions as it would still be necessary to have a relationship management function for the aggregators.

10.6 (S1) and (S2) Performance Assessment

Performance assessment is formulated to understand and analyse two important aspects of the Commercial Trials operation:

- Functional assessment to establish impact, reliability, cost and potential benefit of using DSR as an alternative technique to manage constraints.
- Operational function for the performance contract and financial settlement.

The functional assessment element is not a function of the back office system and has therefore been addressed in section 12.11 as a part of the 'Trial Operation.'

The data collected for the settlement process in the back office is also being used to assess the functional aspects of the commercial techniques. The output requirements of this were to develop the necessary input data to the SIM, in order that the overall effectiveness could be measured against the other alternative techniques and give the SIM the critical information on which to carry out comparisons.

10.7 (S1) and (S2) Financial Settlement

Financial settlement of the participants' role within the DSR service is a necessary aspect of the trials and any subsequent BaU operations. It was also deemed important and of great value to the industry to create a prototype back office system that would be designed around the DNO DSR 'use case' and contractual requirements. In order to provide a fair indicative cost for commercial techniques against the engineering alternatives which are predominantly large capital investments, it is vital to determine a 'whole life' cost.

By developing back office systems to manage the post event analysis and administration, the manual resource requirements are reduced resulting in lower operational costs to the DNO. This should also present the additional benefits of creating a quicker and more accurate process than any manual process.

The calculations outlined earlier in this section are used to assess the performance within the software itself as well as within the contract to express the detail of what a participant is agreeing to in terms of their physical action. The action itself is measured in one minute increments and these are recorded on the daily file that should be submitted to the DNO the following day. Each file contains 1440 readings and if an event has occurred then between 65 and 105 of these should provide the necessary readings to provide an accurate indication of the event performance.

The software, therefore, needs to bring together a number of variable pieces of information for each customer to automate the financial settlement and provide customer statements, as outline below:

Table 8- Software data fields

Requirement	Source	Data type
Contracted Party	Contract	Static
Address	Contract	Static
Customer Reference	Contract	Static
Site(s) Name	Contract	Static
Site Address	Contract	Static
Unique ID	MPAN	Static

Requirement	Source	Data type
Generation or Reduction	Contract	Static
Contracted delivery value	Contract	Static
Critical Delivery % (de-rated capacity)	Programme parameters	Static
Response time	Programme parameters	Static
Maximum event duration	Programme parameters	Static
Minimum event duration	Programme parameters	Static
Event Notification time	Event records	Dynamic
Event cease time	Event Records	Dynamic
Daily data file	Data repository	Dynamic

For the FALCON trials, the back office software was designed by SGC, developed by CGI and hosted within WPD's secure IT environment. WPD operate a policy of limiting internet access only to standalone machines within their offices and not via the corporate IT network. This presented various challenges in creating a suitable test environment and establishing the permissions where FTP data files can be stored and accessed securely.

The operational release of the software was hosted as a packaged application creating a virtual environment that could be accessed by any WPD networked desktop PC. This could in turn access the participant data files that were stored within a secure DMZ (Demilitarized Zone). A DMZ, which can sometimes be referred to as a perimeter network is a physical or logical sub network that contains and exposes an organization's external-facing services to a larger and untrusted network, in this case the Internet. The purpose of a DMZ is to add an additional layer of security to an organization's LAN (Local Area Network); an external attacker only has direct access to equipment in the DMZ, rather than any other part of the network.

With the available data outlined in the table above, the software would retain all the necessary customer and site information that would typically remain static throughout the contract period of the service agreement. The dynamic information would then be uploaded against each participant for the dates on which events occurred. This should be a monthly process although due to a number of technical issues and ongoing software development this was not possible during the trials.

The general methodology of the software was to establish the baseline from which the measurement would take place by creating an average of the five consumptions values recorded prior to the event notification time. Thereafter, the event performance would be broken down into a calculation for each minute of the event that would assess the reduction against the agreed value to determine a binary success result as an overall record of failures that fall below the minimum de-rated delivery. This also generates a payment for each minute that is prorated with the incentive £300 MWh or £600 MWh for T5 in **(S2)**. This is repeated for each one minute increment until the event cease time is reached. From this a customer performance record is generated along with an event statement.

10.8 (S1) Procurement (invoice / billing / payment)

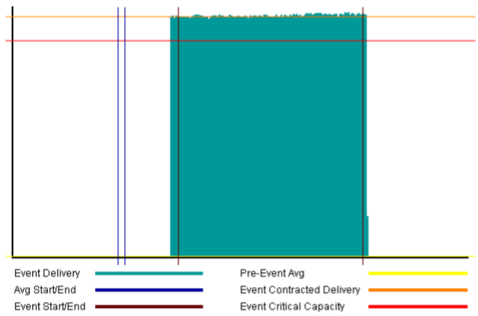
The subsequent processes to complete the payments were completed manually within the trial but could be automated if sufficient volumes were able to justify the additional investment in systems development.

Each contracted party would receive a statement with a copy of all the individual site events as shown below and a summary with the total aggregated payment.

Site Name(SN1)
Unit 1,
SN1 Street,
SN1 Town,
SN1 0AA
Client Ref: 1234567890101 *(mpan)*

WESTERN POWER DISTRIBUTION
Serving the Midlands, South West and Wales

Summary report for the event on 16 December 2013, between the times of 17:52 and 19:39.



Contracted Capacity:	0.6000 MW.
Critical Capacity:	0.5400 MW.
Event Price per MWH:	£300.00.
Event Notification Time:	17:22.
Pre-Event average consumption window:	17:17 to 17:21 inclusive.
Event Start Time:	17:52.
Event End Time:	19:39.
Pre-Event average consumption:	0.0000 MW.
Event Contracted Delivery:	0.6000 MW.
Event Critical Capacity:	0.5400 MW.
Event Exceptions:	0.
Event Capacity Delivery:	1.07933 MWH.
Event Payment:	£323.80.

Figure 26 - Example DSR event statement

If no concerns or disputes occurred with the contracted party they would then submit an invoice for payment that should then be processed for payment within 30 days.

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SECTION 11

Metering Standards

11.1 (S1) Metering

A requirement for the **(S1)** trial was to establish any specific metering standards during the initial stages, as many sites operated by aggregators would already have metering established. It was therefore accepted that, for the purposes of establishing a baseline from which we could test and identify whether this would be adequate for DNO purposes, the existing metering would be acceptable if it could provide one minute granularity. As the primary service in which the majority of aggregator's sites are currently engaged is STOR, it was found that the majority of the generation sites were measured as a positive increase at the generator as opposed to a reduction at the point of import. This also determined that two separate processes needed to be created within the back office systems in order to fulfil settlement processes for both commercial techniques as **T5** would clearly be measuring a reduction in demand.

The metering at aggregator sites use a variety of physical devices ranging from the generators own controls to bespoke meters designed to communicate with their control centres. These were, on the whole, found to be of sufficient accuracy on which to settle the payment process.

Issues did arise with the quality of the data file within a significant number of files received.

The issues were:

- Interpretation of data file format;
- Intermittent submission of files and
- Missing fields corrupting the software file parser.

Most of these issues were addressed during the trial through additional training and process changes. The software was also revised at several stages throughout the trial to address some of the sensitivities to file structure, and additional future functions identified to improve its functionality should a full enterprise version be developed.

With the directly contracted generation site at *Anglian Water*, (AW) it was agreed that we would be granted permission to trial an alternative metering solution. WPD SM (Smart Metering) would arrange the installation of a standard Elster A1700 meter that was configured to one minute increments and installed directly to the output terminals of the generator. There was no current precedent for installing on a live generation asset so new policies were developed in relation to carrying out new commissioning work so that a safe and non-invasive method could be achieved to meet health and safety standards.

SGC provided an experienced engineer who developed a scope of works, method statement and resolved issues with WPD SM and AW's preferred contractor to support commissioning the site's stand by diesel generator. Initial site surveys had to be arranged, metering components specified, ordered and assembled before a date for access could be arranged. Several dates were scheduled to install the meters and were unfortunately delayed on multiple occasions due for a series of different reasons. A series of learning outcomes were achieved in relation to the process of scheduling and completion of the commissioning work, as outlined below:

- Ensuring availability of components for metering in advance of resource scheduling;
- Configuration of meter prior to commissioning;
- Ensuring adequate site access permissions;
- All necessary authorised personnel are available and briefed
- Ensuring method statements and Scope of Works has been reviewed in advance by all parties.

Unfortunately, the meter specification selected for **(S1)** was not suitable for intended purpose of the trial. In addition to active import, several parameters were being recorded and, as a result, the one minute intervals created a larger than expected data file for the data collector to receive. This repeatedly proved to be unsuccessful before the meter timed out its daily download connection and an incomplete and corrupt file was unusable for the purposes of assessing and payment settlement. The accumulation of data rapidly overwhelmed the limited available meter memory, resulting in overwriting of information before it had been received in the data repository.

11.2 (S1) and (S2) I.T. requirements / FTP / data collection

WPD has a very stable IT environment operated by WPD IR. One of the core principals with the IT infrastructure strategy is to maintain security and minimise any external threats by maintaining a very stable environment without any direct access to services such as the internet. It was therefore potentially very challenging to operate a trial that required new software to be hosted within the secure network with access to files for external metering sources.

The initial suggestion by the FALCON Commercial Trials Lead to WPD IR was to keep the software standalone and operate the trial on a test environment on an independent PC or Laptop. WPD IR were keen to offer the trial their full support and ensure that the results were as real as possible, particularly with a reasonable expectation of commercial techniques becoming a BaU activity. The software was therefore tested for compatibility and packaged so as to be accessible via a virtual desktop arrangement. This would ensure that the software only existed centrally in a single release and no rogue versions could result from being installed on several machines. This not only allowed the software version control and licences to be easily managed, it would make the software accessible from any WPD networked desktop by users who were granted user permissions.

During **(S1)** all of the aggregators were then given instructions and a test arranged to ensure that they could securely transmit the data files collected from site meters to a safe zone in the DMZ set up by WPD IR. The files would then be fully scanned for any threats before they

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would be made available to the data repository that could be accessed by the FALCON trials lead.

After the initial setup up, training and testing the IT / IR arrangements worked flawlessly and enabled that the back office software could be tested in a more challenging set of conditions reflecting those that would be expected in BaU.

The variation for **(S2)** resulted in a standardised metering solution across all the participating sites, and these were installed by WPD SM to provide a daily meter download from each site offering a minute by minute record of the previous day's consumption. This was tested prior to the installation of the meters to customer sites and did not result in any issues once deployed. Stark Energy Data Services as the incumbent supplier to WPD successfully carried out the remote collection of the data from the meters which then used standard security and proven FTP methods to supply the data for analysis and back office processing.

11.3 (S2) Meter Types

In relation to the failures of the meter used for the directly contracted site in **(S1)**, the poor performance and shift in overall requirements for **(S2)** necessitated a change request to extend its scope. The increased number and importance of meters within the second season required additional resources to ensure their successful operation. Therefore, in the **(S2)** trials, WPD SM supported a trial of two new devices that were tested in a laboratory environment before a suitable meter was selected for installation at participant sites.

11.3.1 Performance of Elster A1700 during (S1)

Data was obtained from the meter in two methods:

1. Manually dialling the meter using the manufacturer's engineering support software, Power Master Unit (PMU). This is a tool primarily meter configuration and investigation of faults and not suitable for ongoing data collection. PMU data collection was successful but due to the relatively large amount of profile data it is a very time-consuming activity requiring manual intervention.
2. Set up on SSIL's data collection systems for automatic data retrieval. This was the planned method to obtain data during the project.

SSIL were able to set the meter up on their systems and retrieve data from the meter. However, the data was not complete both in terms of time periods where no data was retrieved and where data was not complete across all the channels set up on the meter.

SSIL's analysis showed in took a 45-minute GSM call to collect a single day of 1 minute profile data for a single channel. The requirement for the GSM network to sustain such a long call to retrieve data resulted in lots of failed calls and unreliable data retrieval.

The reason for this slow speed was the two-fold:

1. The primary reason is the Elster A1700 protocol. This can be traced back through ABB A1700 or PPM meter to the GEC PPM (early nineties) and before that the protocol was first used in an Opus data logger from the 80s. More recent meter protocols have taken advantage of modern communications methods and a greater understanding of data transmission resulting in significant improvement in data collection speeds.

There is a further quirk in the Elster protocol requiring a whole day's data to be collected which removes the option to download multiple times per day resulting to benefit from shorter download times. Whilst the early calls would be shorter the last call of the day would still require the whole day to be downloaded taking 45-minutes.

2. The other factor is the communications mode. The data from the Elster was collected by CSD calls over GSM. This is slow and unreliable for such long call durations. Alternative meters would afford the opportunity to use GPRS data collection.

Reliable communications was more critical because the A1700 stored less than 3 days' data with the increased volumes demanded by the trial due to its limited memory capacity so that if the meter was not successfully downloaded regularly the data was overwritten and lost. Typically in HH Settlement a meter has three months' of data stored to allow for delays in data retrieval; by Hand Held Unit if necessary.

There was a further complication in respect of time setting. With 1 min. profiling it is critical to get the meter correctly synchronised with GMT. However, the systems in place to do manage time and correct it are based around 30 min. profiling and although the impact of this needs further investigation there were significant issues with time drift which impacted data quality.

11.3.2 Alternative Metering Solutions

Two alternative metering solutions were trialled for **(S2)**. Both meters were installed locally at WPD's Smart Meter Facility in Bristol in order to carry out intensive lab testing.

1. **EDMI Mk10A.**

   This meter is widely used in the Advance Meter market – for smaller businesses just below the threshold to HH metered. The meter has a faster protocol and more easily supports GPRS communication. SSIL's testing show a single channel of 1 min data can be collected in under 2 min. compared to the 45 min. taken by the A1700.

Figure 27 - EDMI Mk10A

2. **CEWE Prometer.**

Figure 28 - CEWE Prometer

The Prometer is a more technically capable meter with two sets of independent profiles and communications ports. The meter has been requested by some of WPD Smart Metering’s large distributed generation customers because of this increased capability; in particular it allows the customer to have their own monitoring systems connected to one of the two independent communications ports. It was however determined to be too expensive when compared with the EDMI Mk10A as both performed well throughout the testing phase and the additional capital could not be justified.

The purpose of the testing was to establish the performance of the meters in the following respects:

1. Reliable collection of 1 min. import and export kWh data at Day+1
2. Reliable reporting of this data via FTP to WPD
3. Assessment of the time-stability of the meters and of the mechanisms to correct time given the narrow 1 min. width of the profiling
4. A comparison of the data from the two meters
5. An assessment of the time taken and cost to retrieve the data
6. An assessment of the ability of the meter to support by 1 min DSR data and 30 min Settlement data
7. Confirmation of the number of days’ data stored by the meter in case of communications problems.

11.4 Substation – Network monitoring

In **(S1)**, the network monitoring did not require to be carried out at every primary substation therefore, only two substations were selected. Initially, two monitoring devices (Outram, Ranger PM7000) were acquired from another project as a temporary solution to monitor the load at the substation. The primary function of the devices was to carry out comparative analysis on the impact of the action taken at the customer site and determine whether the resulting action on the network is predictable in terms of the load reduction experienced upstream. In order to provide suitable data, the Ranger was configured to

Figure 29 - Outram Ranger PM7000

take data readings at single minute intervals, allowing site and network data to be compared.

The initial data recorded by the Ranger device contained an extensive range of parameters, many of which did not offer any relevance or benefit relating to the purpose of commercial trials. There was also some difficulty in reading the results in a comparative manner as the data output provided by the ranger was in a format intended for reading and display by 'Pronto' software, packaged with the device.

The PM7000 has an extensive capability in excess of the parameters necessary for the commercial trials as it has limited engineering requirements to be investigated. Therefore when a request was submitted from the original project from which they had been acquired, to redeploy them for their original purpose, an alternative device was identified which aligned more appropriately with the FALCON test prerequisites.

Figure 30 - Eltek Squirrel 1000

The PM7000 devices were replaced by Eltek Squirrel 1000 units installed to record the substation data in February 2013. The results recorded were not adequate for comparative analysis, as only three DSR events occurred in the final month giving too small a data set in order to be able to offer analysis with sufficient rigour to offer clear outcomes. The initial testing of the device at the end of the **(S1)** provided positive initial data in a flat file format that is more suited to the comparative analysis desired. **(S2)** was, as a result, monitored by several devices that recorded results at five primary substations as well as two transformers at the 33kV bulk supply point.

Eltek Squirrel 1000

Features:

- Battery or mains operated and easily portable
- Configuration and Metering by:
- Panel controls and display
- Locally connected PC using Darca Software
- Remotely connected PC (using Darca Software) via GSM, landline or radio modem
- Measure up to 250 analogue or digital channels, such as temperature, humidity, pressure, voltage, resistance, current or any other suitable sensor output
- Non volatile internal memory providing up to 2 million readings of secure data

- Readings can be scaled into appropriate units (e.g. m/sec, p.p.m.)
- Low power consumption for long term unattended use or portable operation
- Customised firmware for specialised requirements
- LAN Network adaptor for Ethernet connection
- Highly accurate: ±(0.1% of reading, +0.2% of range span)
- 12 bit resolution
- Sensor power outputs
- 1 pulse count channel and 8 event/digital channels in addition to other inputs
- External triggers can start and stop the logger
- Rapid memory download at 38400 baud
- Up to 99 logging "runs" may be stored

Table 9: Specification

Eltek Squirrel 1000	
Logging Modes	Interval / average / event / externally triggered
Log / Scan Interval	1 sec to 24 hours Optional: 0.1 sec minimum
Analogue Inputs	Accuracy: ±(0.1% of reading, +0.2% of range span) Common mode range: 15V Input Impedance: 1MW
Sensor Excitation	5V / supply voltage - internally selectable Digital Inputs 0 / 5V or volt free contacts 8 inputs per logger channel
Pulse counters	Each counter up to 2KHz signal or 100Hz volt free contact. A total of 650K counts software selectable
Data memory	Internal memory: 250,000 readings Option: 2 million readings or PC slot with SRAM card (2 million readings) Memory modes: stop when full or continuous
Scaling Data	Readings scaled as engineering units
Configuration	Panel controls and display and/or Darca Lite or Darca Plus (PC Software
Display	2 line, 32-character display for local status monitoring, configuration and stored readings
Communications	RS232 half duplex - 2400 to 38.4K Baud Modem compatible protocol
Darca Software	Darca Lite for control, download and export Darca Plus with graphing and analysis tools
Power supply	Internal: 6 x AA Alkaline batteries External: 9 to 14 VDC (1.4 watts) Mains adapter: 12 VDC 6 watts Battery Life: sampling 8 channels every 5 minutes provides typically 6 months operation
Case	Scratch resistant Nextel coated ABS width 180mm, height 120mm, depth - see table below
Operating Environment	Temperature range:-30 to 65°C Humidity: 95% non-condensing. For harsh environments an optional IP67 enclosure is available

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Source: Eltek Specialist Data Loggers. www.eltekdataloggers.co.uk

The **(S1)** distributed generation trials operation commenced on the 1st November 2013 as planned, with an expectation to run until the end of February. Trials for **T5** and **T6** should have been operated in parallel over an identical time period but, due to the absence of any **T5** recruits to test load reduction, a delayed initiation was offered to allow the three aggregators (**Ag2**, **Ag3** and **Ag4**) who had previously declared viable prospects, the additional time required to ready their participants' sites. A further two additional attempts were agreed with the aggregators to offer every possible assistance to the **T5** EP acquisition phase, but this was finally abandoned in April 2014.

The following **(S1)** trials results will therefore be referring specifically to **T6** trials of distributed generation only.

SECTION 12

Trials Operation

12.1 Details of (S1) Events

A total of 18 events were attempted with event number 3 on the 6th of December '13 being prevented from taking place due to an unplanned outage event occurring on network. Permissions were sought from the Control Room duty manager but were not authorised due to the limited availability of network control engineers to check the Milton Keynes trial area due to a limit on resources who were deployed on the major incident elsewhere. The remaining 17 events were approved successfully by the Control room and the table below identifies when they took place and for how long. Due to **(S1)** employing manual dispatch being made by one individual using phone contact, the start times were staggered. Cease calls were also issued in the same order in an attempt to ensure that all sites completed approximately the same event durations.

Table 10 - DSR Event Record

Event Number	Date	Start Time	Duration (h:mm)
1	27th November '13	17:50	1:25
2	28th November '13	16:30	2:00
CANCELLED	6th December '13	-	-
3	9th December '13	16:10	1:40
4	12th December '13	16:00	1:54
5	16th December '13	17:20	1:46
6	20th December '13	17:00	1:47
7	9th January '14	17:05	2:00
8	10th January '14	17:45	1:46
9	14th January '14	16:45	1:53
10	15th January '14	16:20	1:32
11	17th January '14	17:25	1:42
12	22nd January '14	16:10	2:00
13	24th January '14	16:30	2:00
14	27th January '14	17:20	1:05
15	29th January '14	17:00	2:00
16	21st February '14	16:10	2:00
17	24th February '14	16:55	2:00
18	28th February '14	17:05	2:00

12.2 (S1) Performance breakdown (statistics table)

One of the most critical statistics to be analysed within the trials operation was the reliability of DSR against conventional reinforcement or any of the other engineering alternatives being trialled. In order to be viable as a method with which to rely on for network support, DSR not only has to prove to be more economic, it must achieve similar levels of dependability. In order to do so, the benchmark was therefore excess of 95% success for both availability and utilisation.

Availability was measured as declarations for whole weeks, and where the site would be unavailable for any portion of the week, it was recorded as a negative. In the event that an aggregator failed to provide a declaration by the Friday prior to the operational week, it would be automatically assumed to continue to be available or unavailable based upon its state the previous week.

Subsequently, once a site was declared available it would then be included in the utilisation reliability analysis. Utilisation already allows for a de-rated capacity only requiring 90% or above delivery of the contracted capacity. The site is then monitored and data provided at one minute increments. For each interval that the delivery is below the 90% minimum delivery threshold it is recorder as an EoD (Event of Default). With each of the 17 events that were successfully dispatched for the trial, if a participant failed to start or incurred greater than 5 EoDs it would be determined that the utilisation was insufficient and therefore the DSR event recorded as a failure to deliver.

No penalty arbitrary was applied to the participant other than the loss of opportunity to earn the revenue from the FALCON trials as these were performance contracts and any underperformance would result in a pro rata reduction on the customer payment.

12.3 (S1) Reliability

Declared Availability

The diagram below shows the declared availability of the **T6** sites during the trials period and the performance against it.

site	04-Nov	11-Nov	18-Nov	25-Nov	02-Dec	09-Dec	16-Dec	23-Dec	30-Dec	06-Jan	13-Jan	20-Jan	27-Jan	03-Feb	10-Feb	17-Feb	24-Feb
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
1	n	n	n	n	y	y	n	n	n	y	y	y	y	y	y	y	y
2	n	n	y	n	n	n	n	n	n	n	n	n	n	n	n	y	y
3	n	n	y	n	y	y	n	n	n	y	y	y	y	y	y	y	y
4	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n	n
5	n	n	n	y	y	y	n	n	n	y	y	y	y	y	y	y	y
6	na	na	na	na	na	na	n	y	y	y	y	y	y	y	y	y	y
7	y	y	y	y	y	y	y	y	y	y	y	y	y	y	y	y	y
8	y	y	y	y	y	y	y	y	y	y	y	y	y	y	y	y	y
9	y	y	y	y	y	y	y	y	y	y	y	y	y	n	n	y	y
10	y	y	y	y	n	n	n	n	n	n	n	n	y	y	y	y	y
11	y	y	y	y	y	y	y	y	y	y	y	y	y	y	y	y	y

Figure 31 - Week ahead availability declarations

Across the period of the trial, the eleven aggregator sites were operated for a total of 17 weeks. This created a maximum number of availability declarations that could be received of 187. This was reduced to 181 as site 6 was not fully commissioned due to connection permissions requiring to be provided by WPD and was only fully active in the trial week commencing 23rd December. Of the sites that were contracted and expected to participate throughout the trial period there was a total of 61 declarations stating they would be unavailable. The high level results were disappointing, only achieving 66.3% availability, well below the certainty that a DNO would require to rely on DSR as an alternative to engineering based options.

Operational Reliability

Sites	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
1	*na*	1	0	0	1	1	0	0	0	0	0	*na*	0	*na*	0	*na*	0
2	*na*	1	*na*	*na*	1	1	*na*	*na*	*na*	*na*	*na*	*na*	*na*	*na*	*na*	*na*	*na*
3	1	1	*na*	*na*	1	1	*na*	*na*	*na*	*na*	*na*	*na*	*na*	*na*	*na*	*na*	*na*
4	1	1	0	0	1	1	1	0	0	0	0	0	1	1	0	0	0
5	*na*	1	0	0	*na*	*na*	0	0	0	0	0	0	1	1	0	0	0
6	*na*	*na*	*na*	*0*	1	0	0	0	0	0	0	0	0	0	0	0	0
7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
9	0	0	0	0	0	0	1	1	0	0	0	1	1	0	0	1	1
10	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0
11	1	0	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0
12	*na*	*na*	*na*	*na*	*na*	*na*	*na*	*na*	*na*	*na*	*na*	*na*	*na*	*na*	*na*	*na*	*na*

Figure 32 - Performance record of events

Operational reliability was made quite difficult to present a clear outcome for the poor performance in terms of availability declarations had a significant impact on the reduction of assets that were called upon during DSR events. Where an asset was declared unavailable it was removed from the operational reliability analysis. This may in turn have helped to improve the perceived performance of the DSR event dispatch and delivery but unfortunately in BaU environment would still have been unavailable and therefore the 'real world' results being a combination of the two sets of figures resulting a further reduction. From the 66.3% availability that was already acknowledged to be too far below an acceptable standard as to be considered as an alternative to more conventional methods.

Taking the performance of the assets in isolation and disregarding when they had been declared unavailable to operate or where there were issues with the reliability of the metering left a total of 151 potential opportunities for sites to respond to a DSR event. Of this 115 achieved their contracted objective while 36 fell short of the contractual requirements by varying degrees. Unfortunately this resulted in a reliability factor of 76.1% from the available sites, further compounding the concerns that were raised initially from the weekly declarations.

The original intent of the trial was to repeat the processes from **(S1)** again in **(S2)** to give some comparison between the two years, with some expectation of a drop off in reliability for **(S2)** as it would have had less preparatory work done by the project team and therefore the potential of not being in the same state of readiness for the DSR season / events. The opportunity to submit a change request was therefore welcomed as an opportunity to try and address some of the learning achieved in **(S1)**, in particular the disappointing and unacceptable reliability statistics.

12.4 (S1) Sensitivities / results

12.4.1 (S1) Communications

Despite the use of basic communications technology, employing email for weekly declarations and phone calls to manually inform of dispatch and cease times, the operational communications did not result in any failures to provide DSR that were recorded. Two incidents were experienced at the same site, but this wasn't captured in the final statistics as a metering issue meant the events in question could not be analysed properly and the failure of two internal communication processes resulting in a failed and a late start did not contribute to a further reduction in the reliability statistics.

12.4.2 (S1) Assets

The generation assets experienced a range of failures. These were not down to a common cause and combined analysis of the events are included in the **(S2)** final results section. **(S1)** Failures did however include a catastrophic turbo failure on one site during a DSR event. This limited its role in the trial for almost three months until it was possible for a repair to be completed by contractors on behalf of the site owner.

Failures were not limited to the stand by assets and a CHP site which is in regular use and produces several GWh of electricity per annum also suffered a two week period of unavailability due to an unexpected issue relating to controls. This was rectified quickly and fortunately was available on most of the dates during which events occurred.

12.4.3 (S1) Metering

Metering also presented issues on a small number of occasions. When an aggregator operating the sites became aware of the metering issues during a DSR event they contacted the Commercial Trials Lead and were advised to cease their DSR event early to avoid operating but not capturing the data necessary to receive a settlement payment. It was apparent that if this was being used for BaU network support this issue would have largely been administrative and the generator was most likely meeting its objectives. However in the absence of adequate data in order to provide payment to the site there was limited value in keeping the site running and incurring costs, as the data necessary to support the trials and provide financial settlement was not being collected.

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The main metering issue for **(S1)** related to the in-house solution to capture data from the directly contracted participant with a modified settlement meter. Other minor issues were also experienced in relation to the format and integrity of the provided data which are explained in section 11

12.4.4 (S1) Triad interaction

Another of the areas of additional interest was to map the interaction between triad avoidance activity between aggregators, electricity supplier and the potential DNO utilisation requirements. Unfortunately the winter of 2013 / 14 was a very unusual year with results that make it very difficult to extrapolate to any firm conclusions from:

- 25th November 2013, 1700-1730 (period 35)
- 6th December 2013, 1700-1730 (period 35)
- 30th January 2014, 1700-1730 (period 35)

An unseasonably mild winter with a great deal of damp conditions rather than any distinctly cold days made triad predictions very difficult to call for all parties participating. Consequently it would appear that all energy suppliers did not issue warnings to their customers on the 6th December. This is the first time in forty years that an annual peak demand period has occurred on a Friday and to some extent the reason that this became a triad event. This is due in part to the failure of all suppliers forecasting a high demand period coupled with very little variance between several of the surrounding winter high demand periods.

The general assumption by suppliers that triad event does not occur on a Friday led to a failure to declare the 6th December as a potential or probable candidate. As a result of the lack of demand mitigation from triad avoidance participants was ultimately the main contributing factor as to why the demand was sufficiently high to become a peak.

12.4.5 (S1) Billing / settlement

The software releases that CGI were able to provide during the trials process were early development forms of the software that did not include an easy to use graphical interface or many of the features that would be expected in a full release enterprise edition. The trial was able to demonstrate a scalable application that could store a large number of participants and events demonstrating its functionality to administer many variables for DSR programmes across a DNO's franchise area.

The processing of the events was coupled with software debugging and the early event processing experienced many difficulties due to inflexibility within the software to process files that did not adhere exactly to the format requested. This included process corruption even if a single data field contained within the metering files was incorrect or missing. This, in turn, highlighted data integrity issues with the data being received from more than one site on repeated occasions.

While the software was functional, the parallel development and debugging proved very time consuming. Consequently the trials were unable to meet the expected monthly timescales set out at the beginning of the trial for monthly statements and payments. On average the payments were 4 to 6 weeks behind and overall the aggregators demonstrated patience and understanding in relation to the delays. The screen shots below show the operation of the DRS software and the customer statement - an output of the software:

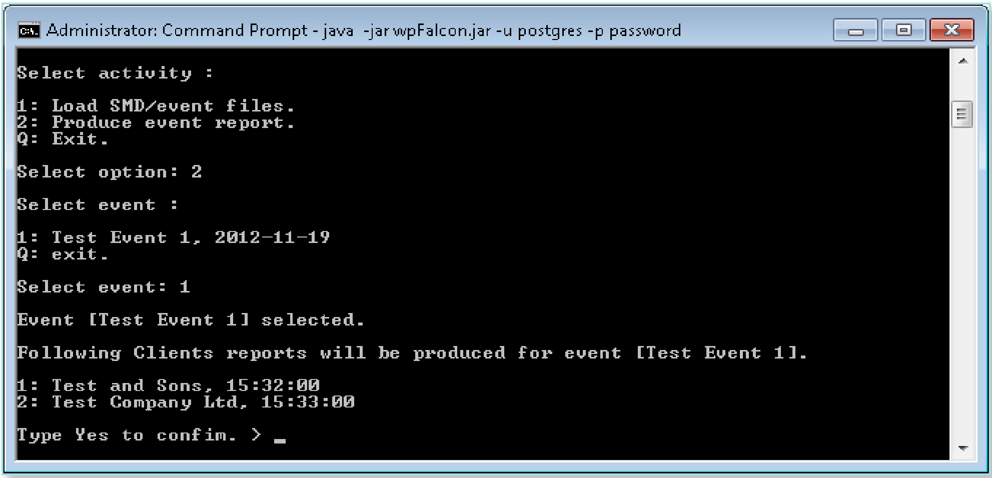


Figure 33 - Command prompt control screen for (S1)

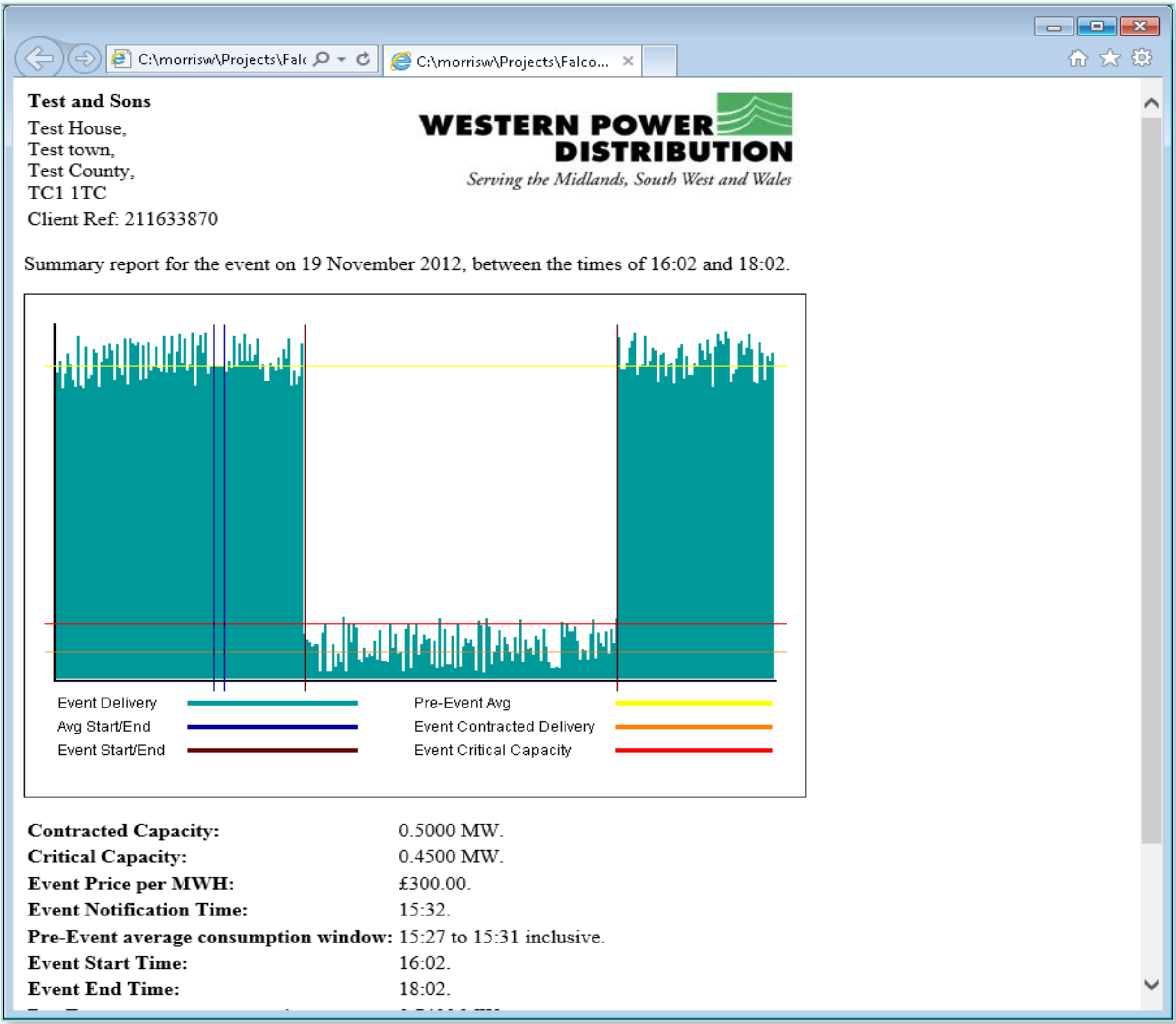


Figure 34 - Sample (S1) load reduction event statement

(S2) required significant functionality developments in order to support the changes to the trials scope for 2014/15. Further information on the scope changes for the trials are published in section 18.

12.4.6 (S1) Customer report samples

The software ultimately proved the efficacy of the calculation algorithms developed for the FALCON trial and supports measurement and settlement of the customer data in the manner set out in the initial design of the trials. Attitudinal analysis carried out in relation to the clarity and detail of the reporting was all positive with acknowledgement given to simplicity of understanding.

The statements shown below are actual results from the trial that have been anonymised.

Aggregator Name (Ag?)
1 Street Name St,
Town name,
TN1 0AA

WESTERN POWER DISTRIBUTION
Serving the Midlands, South West and Wales

Payment Summary – December 2013

Event Date	Site	Payment
9th Dec	Site Name(SN1)	£302.81
12th Dec	Site Name(SN1)	£23.96
16th Dec	Site Name(SN1)	£323.80
20th Dec	Site Name(SN1)	£ 0.00

Sub Total **£ 650.57**

VAT **£ 130.11**

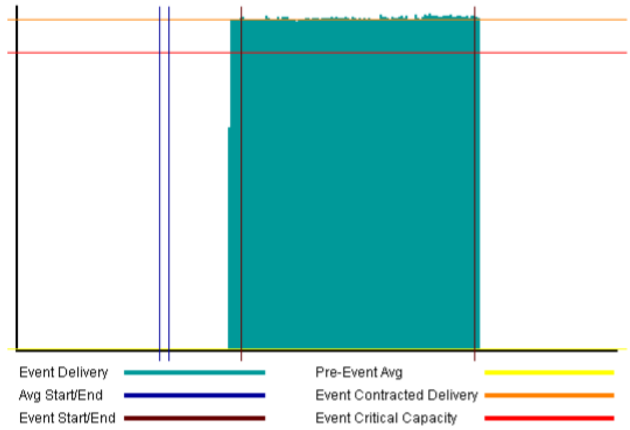
Total **£ 780.68**

Figure 35 - (S1) sample monthly event result / statement

Site Name(SN1)
Unit 1,
SN1 Street,
SN1 Town,
SN1 0AA
Client Ref: 1234567890101 *(mpan)*

WESTERN POWER DISTRIBUTION
Serving the Midlands, South West and Wales

Summary report for the event on 09 December 2013, between the times of 16:40 and 18:20.



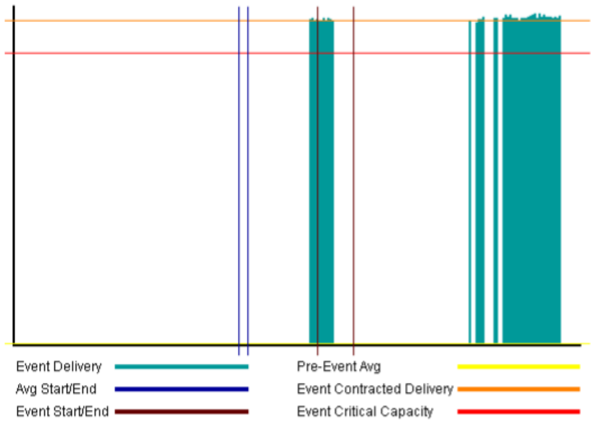
Contracted Capacity:	0.6000 MW.
Critical Capacity:	0.5400 MW.
Event Price per MWH:	£300.00.
Event Notification Time:	16:10.
Pre-Event average consumption window:	16:05 to 16:09 inclusive.
Event Start Time:	16:40.
Event End Time:	18:20.
Pre-Event average consumption:	0.0000 MW.
Event Contracted Delivery:	0.6000 MW.
Event Critical Capacity:	0.5400 MW.
Event Exceptions:	0.
Event Capacity Delivery:	1.00937 MWH.
Event Payment:	£302.81.

Figure 36 - Sample (S1) successful generation event statement

Site Name(SN1)
Unit 1,
SN1 Street,
SN1 Town,
SN1 0AA
Client Ref: 1234567890101 *(mpan)*

WESTERN POWER DISTRIBUTION
Serving the Midlands, South West and Wales

Summary report for the event on 12 December 2013, between the times of 16:30 and 16:46.



Contracted Capacity:	0.6000 MW.
Critical Capacity:	0.5400 MW.
Event Price per MWH:	£300.00.
Event Notification Time:	16:00.
Pre-Event average consumption window:	15:55 to 15:59 inclusive.
Event Start Time:	16:30.
Event End Time:	16:46.
Pre-Event average consumption:	0.0000 MW.
Event Contracted Delivery:	0.6000 MW.
Event Critical Capacity:	0.5400 MW.
Event Exceptions:	9.
Event Capacity Delivery:	0.07987 MWH.
Event Payment:	£ 23.96.

Figure 37 - Sample (S1) failed event generation statement

12.5 Details of (S2) Events

A total of 27 events were notified to the participants. Notifications were also provided to the Control Room duty manager on the same timeframe as the participants by means of an email with a schedule of events for the following week. As with **(S1)** the sites should already have all the appropriate connection permissions allowing them to run freely as long as the network is stable and in a standard configuration. An exception to this was discovered with one of the sites, preventing it from participation as expected.

The Control Room were also contacted on the day of each event to serve as a reminder of the trial operation, to confirm that there were no unexpected issues and identify who the duty manager would be on that day. There were no unexpected incidents in **(S2)** that prevented the events going ahead as planned or ceasing after underway.

The dates for the events were identified through energy demand forecasting techniques that were necessary to determine the ability to provide week ahead forecasts of the potential load on the network. More details of this are available in section 12.8

Table 11 - DSR events record

Event Number	Date	Start Time	Duration (h:mm)
1	1st December '14	16:30	2:00
2	2nd December '14	16:30	2:00
3	8th December '14	16:30	2:00
4	9th December '14	16:30	1:30
5	10th December '14	16:30	1:00
6	15th December '14	16:30	1:30
7	18th December '14	15:00	1:00
8	19th December '14	16:30	1:30
9	5th January '15	16:30	1:30
10	12th January '15	16:30	1:30
11	13th January '15	16:30	1:30
12	14th January '15	16:30	1:30
13	15th January '15	16:30	1:00
14	19th January '15	16:30	1:30
15	20th January '15	17:00	1:00
16	21st January '15	17:00	1:00
17	22nd January '15	16:30	1:00
18	23rd January '15	16:30	1:00
19	26th January '15	16:30	1:30
20	27th January '15	16:30	1:30
21	28th January '15	16:30	1:00
22	29th January '15	16:30	1:00
23	2nd February '15	17:00	1:00
24	3rd February '15	17:00	1:00
25	4th February '15	17:00	1:00
26	10th February '15	17:00	1:00
27	11th February '15	17:00	1:00
TOTAL			**35:00**

12.6 (S2) Performance breakdown (statistics table)

As with **(S1)** one of the most critical statistics to be analysed within the trials operation was the reliability of DSR and given the lower than desired results from short notification of event dispatch it was important that the longer duration also assisted reliability improvements. The targets remained unchanged, in order to be viable as a method with which to rely on for network support, a benchmark in excess of 95% success for both availability and utilisation.

Availability was again measured as declarations for whole weeks, and where the site would be unavailable for any portion of the week, it was recorded as a negative. On each Monday a notification was sent to the nominated contact for each participant. Most weeks the emails were sent as intended, before midday on the Monday of each week, containing a simple schedule of requirements for the following week, thus providing a minimum of 7 days' notice through to 11 days for the Friday. This detailed the specific parameters for the event requirements and a sample of this is available in section 12.10.1

12.7 (S2) Availability Exceptions

There were two sites that were unavailable throughout the course of the **(S2)** trial and these have been removed from the overall reliability statistics in line with the exceptions policy from **(S1)** in order to maintain a consistent approach and enable a fair comparison of results between **(S1)** and **(S2)**.

One of the sites that was using two stand by generators to participate in the trial had been involved during **(S1)** but had not undergone a detailed audit of the connection permissions that had apparently been granted. During the period from completion of **(S1)** through to the briefings for **(S2)** changes the site had encountered some issues with their site operation of the generation for regular testing and participation with STOR via an aggregator. A change of parking arrangements adjacent to the customer's generation enclosures had unexpectedly resulted in an intermittent fault with line of sight communications with the substation and main supply interface with WPD. This line of sight link was to provide an additional data link that allowed the generator controls to monitor voltage levels on the network, and automatically reduce generator output if operating outside of pre-agreed parameters. This failure of communications had already been recognised by the aggregator responsible for generator operation and they had taken responsible actions by withdrawing their involvement in commercial operation of the generators. As part of Project FALCON, WPD were keen to see if this could be resolved in order to allow the site to return to earning revenue from STOR, avoid triads as well as participate in **(S2)**.

A detailed inspection unfortunately revealed that despite having been involved in the process of connection applications previously, and involvement with WPD's predecessor Central Networks the authorisation process had not been completed. The original connection had never actually been granted and the site did not possess the necessary paperwork in order to allow paralleling or export of electricity from the site. It was therefore necessary to withdraw this from the trial. WPD did acknowledge the problem and commenced the process to resolve the error. This resulted in a re-analysis of the network that determined the issue of high voltage levels was no longer present and the line of sight communications that had resulted in the identification of the procedural problem could be decommissioned in favour of a standard export agreement.

A second site that has been omitted from availability has been omitted from availability reliability statistics was attempting to join the trial as a new participant offering **T5** load reduction. It had also attempted to enrol in the **(S1) T5** and had been one of the two potential aggregator sites offered the delayed trials periods in order to help with their lack of readiness. Unfortunately **(S2)** was in many respects similar to **(S1)** and a continued failure of the aggregator to resolve their internal technical issues and secure contracts with the prospect site meant that they again failed to get anywhere close to a state where the site would be able to participate. This has resulted in a very concerning outcome as the aggregator continued throughout this period to insist on their closeness to achieving their objectives and attempted to maintain an expectation that they could resolve issues in time to get involved. The impact of this is addressed in the 'Final Conclusions' in section 14

12.8 Event forecasting

During **(S1)** the trials attempted to test a variety of different scenarios to test the reliability and accuracy of controlling customer behaviours in different conditions and this resulted in a relatively random pattern of dispatch notices so that we could see the impact of

- Dispatch notices at earliest and latest times within availability window
- Minimum and maximum duration runs
- Days of week
- Automatic cessation at max contracted run duration
- Overlap and interaction with triad avoidance

For **(S2)** a different set of objectives were developed that will be far more in keeping with a 'business as usual' requirement for DNOs. Currently a DNO does not require to consider to any great extent the forward forecasting of demand on the network or the energy usage patterns of the users on the network. This is largely due to the historical design and operational parameters of the network where infrastructure is over specified in order that it can meet the peak demands from centralised generation sources. Under such design characteristics the network would still only be loaded to a maximum of 50% at any given point during a peak event in order that if a single point failed, there would be adequate redundancy in the remaining assets that the network could still be supported. As the networks become more active and generation / demand volatility changes the usage

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patterns, more advanced design and control methods are increasingly necessary. One activity that will be critical to this will be the transition away from simply acting as a conduit to the energy flows, but be able to forecast and understand the network requirements as part of an 'Energy Management' function.

A first attempt at this was trialled with regards to managing the Distribution Network peaks in conjunction with the National Peaks, which are used to calculate TNUoS charging. More information on the details of TNUoS and Triad avoidance is provided in section 19.4.1

Avoidance of consumption via the mains electricity supply during three peak demand periods (subject to additional rules). Is potentially a very valuable activity to avoid TNUoS charges which are used to establish an annual charge mechanism that pays for the high voltage transmission network. There is therefore a direct value to the overall system efficiency if DNOs can co-ordinate local DSR impact with the national demand pattern, but this also accords closely with local demand peaks also. The **(S2)** trial therefore attempted to use access to a range of available data to carry out analysis and provide effective predictions of peak load periods and attempt to mitigate these using the participant sites.

Triad or TNUoS avoidance is an activity that most electricity suppliers providing warnings to their customers for and in addition aggregators and a handful of energy advisory organisations can provide commercial services to assist customers. These however typically only operate on a day-ahead or in-day time frame so the attempt to achieve reliable results up to 11 days in advance could be potentially very challenging.

In order to make reasonable predictions of National and Local Demand the Commercial Trials lead required to purchase a subscription to a commercial weather data site to gain access to more detailed and longer term forecasting services than are readily available through normal online providers. Using www.netweather.tv we accessed

- 7 day UK forecast
- 10 Day UK Forecast
- 8-14 Day Local Forecast
- Jet Stream Forecast
- 16 Day average temperature forecast

This was then correlated against national demand data from National Grid in the previous year and historic temperature data for those dates. Finally we measured this against National Grid's own demand forecasts, all of which were available via www.bmreports.com. Based on this we were able to operate a relatively successful programme of events that was successful in operating during both local and national demand peaks. The accuracy of this improved over the course of the trial as the timing of the local peak was sometimes out of accord with that of the national profile and tended to be slightly earlier when analysed against our 33kV monitoring. We did fail to correctly predict the first of the three National Peak events but based on the learning achieved once the operational phase was fully underway managed to predict the remaining two.

The table below shows provides a record of the transmission network forecast at day ahead and the final demand alongside the average daily temperature throughout the trial period. In addition the triad periods are marked in darker blue with the shadow they cast for ten days that is intended to ensure that they remain spaced across the winter period.

Table 12 - DSR Event record correlated with weather and daily peak demand

Day	Date	Transmission Outurn Peak	Transmission Outurn Period	Temp (°C)	Start	Cease	duration
Sat	01/11/2014	38925	36	14.7			
Sun	02/11/2014	41380	36	13.8			
Mon	03/11/2014	48582	36	11.5			
Tue	04/11/2014	49229	35	9.1			
Wed	05/11/2014	49893	35	8.5			
Thu	06/11/2014	48348	35	8.1			
Fri	07/11/2014	47047	35	9.6			
Sat	08/11/2014	43200	35	9.8			
Sun	09/11/2014	45163	35	9.2			
Mon	10/11/2014	50137	35	9.1			
Tue	11/11/2014	48856	35	10.1			
Wed	12/11/2014	48676	35	10.5			
Thu	13/11/2014	47889	35	10.9			
Fri	14/11/2014	47587	35	11.3			
Sat	15/11/2014	44235	36	10.1			
Sun	16/11/2014	45063	35	9.7			
Mon	17/11/2014	49708	36	9.5			

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Tue	18/11/2014	49346	35	9.3				
Wed	19/11/2014	49995	35	9.4				
Thu	20/11/2014	50344	35	8.8				
Fri	21/11/2014	48821	35	8				
Sat	22/11/2014	44752	35	10.2				
Sun	23/11/2014	46096	35	9				
Mon	24/11/2014	51592	35	7.1				
Tue	25/11/2014	51625	34	5.2				
Wed	26/11/2014	51193	35	6.1				
Thu	27/11/2014	50843	35	7				
Fri	28/11/2014	48252	35	8.5				
Sat	29/11/2014	44708	36	9.3				
Sun	30/11/2014	45245	35	9.3				
Mon	01/12/2014	51270	35	8.2	16:30	18:30		02:00
Tue	02/12/2014	51580	35	7.6	16:30	18:30		02:00
Wed	03/12/2014	51541	34	5.7				
Thu	04/12/2014	52113	35	5.1				
Fri	05/12/2014	51087	35	5.1				
Sat	06/12/2014	46524	35	4.2				
Sun	07/12/2014	46414	36	6.2				
Mon	08/12/2014	52106	35	5.5	16:30	18:30		02:00
Tue	09/12/2014	51855	35	4.9	16:30	18:00		01:30
Wed	10/12/2014	51255	35	5.7	16:30	17:30		01:00
Thu	11/12/2014	50719	34	5.9				
Fri	12/12/	51105	35	5.8				

	2014						
Sat	13/12/ 2014	48134	35	4.2			
Sun	14/12/ 2014	46147	35	5.6			
Mon	15/12/ 2014	52045	35	5.9	16:30	18:00	01:30
Tue	16/12/ 2014	51511	34	5.5			
Wed	17/12/ 2014	50587	35	8.5			
Thu	18/12/ 2014	48598	35	10.5	17:00	18:00	01:00
Fri	19/12/ 2014	47470	35	9.1	16:30	17:30	01:00
Sat	20/12/ 2014	45404	36	8.5			
Sun	21/12/ 2014	42489	35	8.7			
Mon	22/12/ 2014	46719	35	10.4			
Tue	23/12/ 2014	45683	36	10.8			
Wed	24/12/ 2014	42209	35	9			
Thu	25/12/ 2014	35847	34	7.4			
Fri	26/12/ 2014	40298	34	5.4			
Sat	27/12/ 2014	44360	35	5.1			
Sun	28/12/ 2014	44772	35	2.8			
Mon	29/12/ 2014	48870	36	2.1			
Tue	30/12/ 2014	48234	35	2			
Wed	31/12/ 2014	45555	35	2.9			
Thu	01/01/ 2015	39385	35	6.6			
Fri	02/01/ 2015	46040	35	6.9			
Sat	03/01/ 2015	46252	36	5.7			
Sun	04/01/ 2015	47304	35	3.4			
Mon	05/01/ 2015	50638	35	5.3	16:30	18:30	02:00

Tue	06/01/2015	50676	35	6.6			
Wed	07/01/2015	50530	35	7			
Thu	08/01/2015	49999	35	7.2			
Fri	09/01/2015	48135	35	8.8			
Sat	10/01/2015	44712	36	9.1			
Sun	11/01/2015	45441	35	7.5			
Mon	12/01/2015	51019	35	8.7	16:30	18:00	01:30
Tue	13/01/2015	50347	35	7.1	16:30	18:00	01:30
Wed	14/01/2015	50930	35	5.5	16:30	18:00	01:30
Thu	15/01/2015	50370	35	5.9	16:30	17:30	01:00
Fri	16/01/2015	50646	35	5.5			
Sat	17/01/2015	48432	36	3.8			
Sun	18/01/2015	48848	35	2.9			
Mon	19/01/2015	53693	35	2.3	16:30	18:00	01:30
Tue	20/01/2015	53185	35	0.9	17:00	18:00	01:00
Wed	21/01/2015	53611	35	1.7	17:00	18:00	01:00
Thu	22/01/2015	53164	36	1.7	16:30	17:30	01:00
Fri	23/01/2015	51598	35	1.4	16:30	17:30	01:00
Sat	24/01/2015	48065	36	3.1			00:00
Sun	25/01/2015	46818	36	4.5			00:00
Mon	26/01/2015	52148	35	6.2	16:30	18:00	01:30
Tue	27/01/2015	52264	36	6.6	16:30	18:00	01:30
Wed	28/01/2015	51240	36	6.3	16:30	17:30	01:00
Thu	29/01/2015	52738	36	5.1	16:30	17:30	01:00
Fri	30/01/	51011	36	4.4			

	2015						
Sat	31/01/2015	46605	36	4.2			
Sun	01/02/2015	48194	36	4			
Mon	02/02/2015	53446	36	2.7	17:00	18:00	01:00
Tue	03/02/2015	52606	36	2.1	17:00	18:00	01:00
Wed	04/02/2015	52581	36	2.2	17:00	18:00	01:00
Thu	05/02/2015	53150	36	2.8			
Fri	06/02/2015	52384	36	2.4			
Sat	07/02/2015	47966	36	2.7			
Sun	08/02/2015	47323	37	2.9			
Mon	09/02/2015	52117	37	4.1	17:00	18:00	01:00
Tue	10/02/2015	52348	36	3.9	17:00	18:00	01:00
Wed	11/02/2015	52795	36	4			
Thu	12/02/2015	52176	36	4.1			
Fri	13/02/2015	49784	36	5			
Sat	14/02/2015	45895	37	6			
Sun	15/02/2015	44846	37	6.6			
Mon	16/02/2015	50824	37	6.5			
Tue	17/02/2015	50135	37	6.1			
Wed	18/02/2015	48924	37	7			
Thu	19/02/2015	50626	37	7.2			
Fri	20/02/2015	49312	37	6.1			

12.9 (S2) Reliability

Declared Availability

The diagram below shows the declared weekly availability of the participating sites during the trials period and the performance against it.

Table 13 - Week ahead availability record

Site	03/11/2014	10/11/2014	17/11/2014	24/11/2014	01/12/2014	08/12/2014	15/12/2014	22/12/2014	29/12/2014	05/01/2015	12/01/2015	19/01/2015	26/01/2015	02/02/2015	09/02/2015	16/02/2015	23/02/2015
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
1	no events	no events	no events	no events	y	y	y	no events	no events	y	y	y	y	y	y	no events	no events
2	no events	no events	no events	no events	y	y	y	no events	no events	y	y	y	y	y	y	no events	no events
3	no events	no events	no events	no events	y	y	y	no events	no events	y	y	y	y	y	y	no events	no events
4	no events	no events	no events	no events	y	y	y	no events	no events	y	y	y	y	y	y	no events	no events
5	no events	no events	no events	no events	y	y	y	no events	no events	y	y	y	y	y	y	no events	no events
6	no events	no events	no events	no events	y	y	y	no events	no events	y	y	y	y	y	y	no events	no events
7	no events	no events	no events	no events	y	y	y	no events	no events	y	y	y	y	y	y	no events	no events

Across the period of the trial, the participating sites were operated for a total of 17 weeks. This created a maximum number of availability declarations that could be received of 119. Due to the change of operational conditions during **(S2)** it was not necessary for the sites to declare themselves available for every week of the trial as they were not going to be receiving a further instruction after this time to request a DSR action to take place. We have therefore reduced the declarations of availability down to the 9 weeks during which events took place. The maximum number of declarations therefore dropped down to a maximum of 63. The shift in results from just 66.3% in **(S1)** to a full 100% availability declarations was a dramatic change that is very encouraging for potential future BaU usage.

Operational Reliability

Table 14 - Operational reliability event record

Sites	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
1	0	29	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	0	28	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	1	1	1	1	1	1	1	1
4	0	0	0	0	0	0	0	0	0	0	0	0	0	17	0	0	0	0	0	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0	0	0	0	0	0	37	0	0	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	0	0	27	5	4	0	60	0	0	0	0	60	0	0	0	0	0	0	0	0	0
7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

The operational reliability, like that of **(S1)** was generally very good. The table above shows the seven sites that participated across the 27 events that were dispatched during **(S2)**. The number in each box represents the number of EODs (Events of Default) which 1 minute intervals during which the site failed to achieve at least 90% of its contracted reduction capacity. We still regard the event as an overall successful delivery if it achieves 4 or less EODs and in only one case a site encountered between 5 and 9 EODs which highlights a potential concern but for statistical reporting is also regarded as successful. If a site encounters 10 or more it is determined as having failed and the event is recorded as a failure against the required reliability standard.

Using the simple analysis of a total of 197 events with only 7 having failed to meet the desired standard a very encouraging result of 96.3% overall operational reliability was achieved.

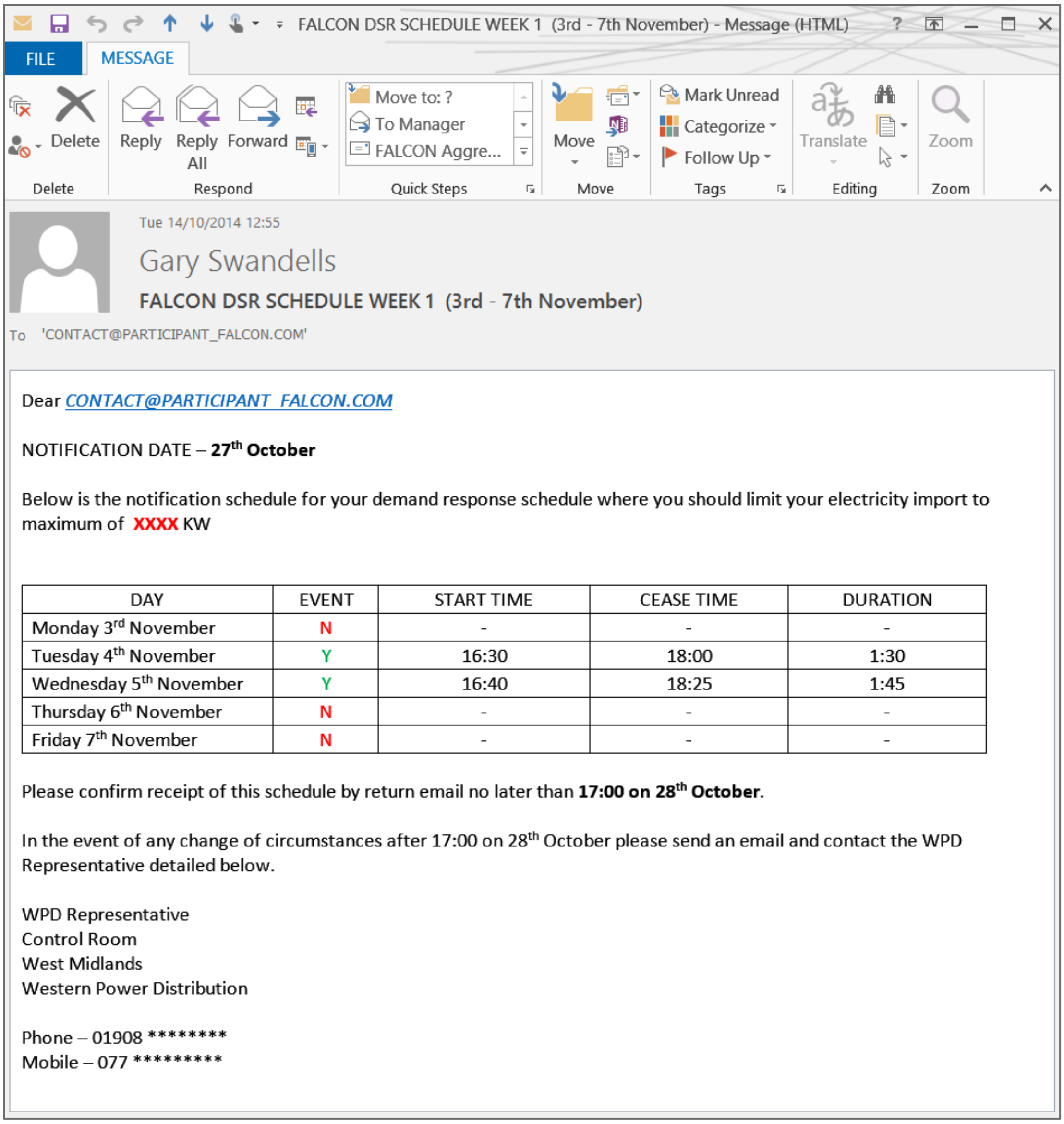
For further information regarding the nature of the failures see 'Assets' in section 12.10.2

12.10 (S2) Sensitivities / results

12.10.1 Communications

As previously outlined in this document, one of the primary changes to the trials operation in **(S2)** was the move away from 30 minute notification of an event to the longer week ahead period. This was carried out every week throughout the course of the trial with the first of the notifications actually being issued in October ahead of the 1st November which is the official commencement of the winter season within the energy industry. On each Monday a notification was sent to the nominated contact for each participant. In the case of sites being managed by a third party aggregator, allowed to be a combination of the aggregator control room, site contact or both. The emails were sent before midday on the Monday of each week, containing a simple schedule of requirements for the following week, thus providing a minimum of 7 days' notice through to 11 days for the Friday. There was a single exception to this on the 29th December, when for circumstances out with the control of the CTL it was not possible to dispatch notifications on time. These were subsequently issued the following day with the same 24hr response period. All of the participants accommodated this unforeseen issue and responded as requested.

The notification emails sent provided specific parameters for the event requirements in a format similar to that shown below.



FALCON DSR SCHEDULE WEEK 1 (3rd - 7th November) - Message (HTML)

Tue 14/10/2014 12:55

Gary Swandells

FALCON DSR SCHEDULE WEEK 1 (3rd - 7th November)

To 'CONTACT@PARTICIPANT_FALCON.COM'

Dear *CONTACT@PARTICIPANT_FALCON.COM*

NOTIFICATION DATE – **27th October**

Below is the notification schedule for your demand response schedule where you should limit your electricity import to maximum of **XXXX** KW

DAY	EVENT	START TIME	CEASE TIME	DURATION
Monday 3rd November	N	-	-	-
Tuesday 4th November	Y	16:30	18:00	1:30
Wednesday 5th November	Y	16:40	18:25	1:45
Thursday 6th November	N	-	-	-
Friday 7th November	N	-	-	-

Please confirm receipt of this schedule by return email no later than **17:00 on 28th October**.

In the event of any change of circumstances after 17:00 on 28th October please send an email and contact the WPD Representative detailed below.

WPD Representative
Control Room
West Midlands
Western Power Distribution

Phone – 01908 ********
Mobile – 077 *********

Figure 38 - weekly email notification sample

If an email response was not received by 5pm on the Tuesday following receipt of the email contact the Commercial Trials Lead would prompt this with a subsequent call. The rules set out in the participant’s guidance stated that if this was also unsuccessful the site would be declared as unavailable for the following week. Despite the follow up call being required on a few occasions towards the beginning of the **(S2)** trial, the escalation to assumed ‘unavailable’ state never arose, and as the participants became familiar with the process, the responses were received reliably, removing the necessity to

12.10.2 Assets

The generation assets experienced very limited failures during the course of **(S2)** despite the increased number of events being dispatched, rising from 18 **(S1)** to 27. Of these only one resulted from a failure due to the asset itself where the generator had a failure, that resulted in a cracked housing t the turbo. The impact of this was a dramatic reduction in the output of the generator, as well as the emission of exhaust gasses and smoke within the generator enclosure that ultimately triggered the fire alarms. The fire emergency procedure was initiated so that the generator was stopped and the emergency services contacted.

12.10.3 Metering

Metering also presented issues on a small number of occasions. When the aggregator operating the sites became aware of the metering issues during a DSR event they contacted the Commercial Trials Lead and were advised to cease their DSR event early to avoid operating but not capturing the data necessary to receive a settlement payment.

Other minor issues were also experienced in relation to the format and integrity of the provided data which are explained in section 12.4.5

12.10.4 Triad interaction

As with **(S1)** a key area of interest was to map the interaction between triad avoidance activity between aggregators, electricity supplier and the potential DNO utilisation requirements. Similarly to the winter of 2013 / 14 the overall conditions made predictions difficult with a variances between peak days remaining very small:

- 4th December 2014, 1700-1730 (period 35)
- 19th January 2015, 1700-1730 (period 35)
- 2nd February 2014, 1730-1800 (period 36)

An unseasonably mild winter with a great deal of damp conditions rather than any distinctly cold days made triad predictions very difficult to call for all parties participating. This was made increasingly difficult when attempting to do so 7 to 11 days in advance. It would appear however for many of the providers of warnings and commercial avoidance services that they had greater success than in **(S1)** where the majority of them missed the Friday event.

The general outcome for the trials area was that there is a strong correlation with the periods during which local peak loads were experienced. If there was a pattern of variance pattern it was relatively subtle would appear that the peak within the trials area was experienced slightly earlier than that of the national peak with it sometimes occurring in the earlier half hourly period.

12.10.5 Billing / settlement

The back office and billing software was based on the **(S1)** release but required a very significant revision in order to make it compatible with the new requirements of the **(S2)** trial, but also to address some of the usability concerns that were raised about the user control interface. While the general functionality may be deemed to be similar and the final statement that are output are also similar the software required a great deal of work in order to meet the new high level design. Much of this was already covered in Section 10.2 which explains the need for the new calculation algorithm in order to shift from delta shift measurement to a consumption cap.

From a user perspective the software for **(S2)** benefitted greatly from a very helpful and friendlier user interface than **(S1)** that reduced the number of errors that occurred during monthly accounts processing. This combined with the improved data file integrity that was facilitated by the having a standardised meter for all sites meant that the billing process was completed two weeks ahead of schedule for the final February statements.

Despite this the software would still require additional development in order to support a full enterprise release, as it was still restricted by the necessity to process each site and each event individually. It was therefore still relatively labour intensive and batch processing would be required before it could be worthwhile commissioning for BaU.

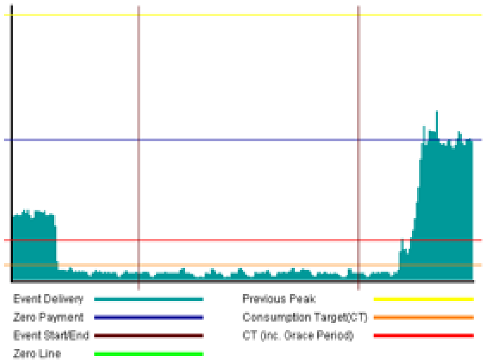
12.10.6 Customer report samples

The general view on the reporting for **(S1)** and **(S2)** was similarly positive. The software ultimately proved the efficacy of the calculation algorithms developed for the FALCON trial and supported measurement and settlement of the customer data in the manner set out in the initial design of the trials. Attitudinal analysis carried out in relation to the clarity and detail of the reporting was all positive with acknowledgement given to simplicity of understanding.

The event shown below was an actual result from the trial that has been anonymised.

Example Site (1100087654321)	WESTERN POWER DISTRIBUTION *Serving the Midlands, South West and Wales*
Address1, Milton Keynes, MK99 9ZZ	
Client Ref: 9900012345678	

Summary report for the event on 08 December 2014, between the times of 16:30 and 18:30.



Event Price per MWH:	£600.00.
Event Start Time:	16:30.
Event End Time:	18:30.
Desired Delta:	0.200 MW.
Previous Peak:	0.216 MW.
Event Target:	0.016 MW.
Target (inc. Grace Factor):	0.036 MW.
Point At Zero Payment:	0.116 MW.
Events Of Zero Payment:	0.
Maximum Potential Payment:	£240.00.
Events of Default:	0.
Actual Event Payment:	£240.00.

Figure 39 - anonymised (S2) statement

12.11 Key Learnings

12.11.1 Industry / Market

A primary focus of the commercial trials has been to understand in detail the broader market for commercial techniques and the potential role of a DNO amongst a growing

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number of actors and influences. This has helped with the development of a view that altered since the formation of the trials and one that influenced **(S2)** as well as shared interim finding to support the work of Ofgem WS6 and The Shared Services group.

12.11.2 Environment / Carbon

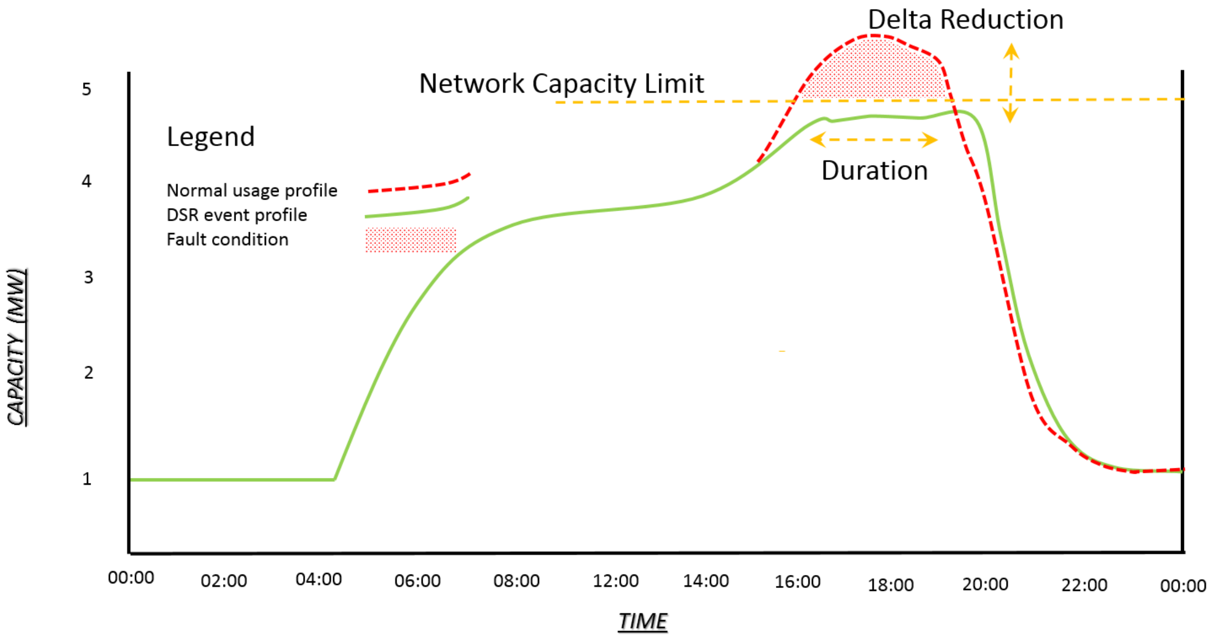
WPD are working with CGI across all of the techniques being trialled to establish environmental and carbon impact of each. This work is ongoing and will be reported in the final trials report, carbon benefits analysis to be published late 2015, as well as potentially provide an additional tier of learning that may support decision criteria used by the SIM.

12.11.3 Distribution Network Operators

In respect of the type of constraint expected that DSR will provide a potentially suitable resolution is likely to be defined by the following characteristics:

- Occasional or uncertain constraint (<20 events per annum);
- Short duration (<2 hours per event);
- Marginal in relation to total overall substation capacity and
- Feeding industrial and commercial sites that have sizable loads with flexibility or generation.

The diagram below shows that the 'in-day' requirement for DSR can be identified by the general shape of the red shaded area. The size of the red area depicts the overall cost of operating the event and the economic use case is based upon achieving a reliable response that resembles the profile pattern below.



Load Profile of Constrained Substation

As a key output of the trial it is important that we then take the data that we have obtained from the 11kV substations in order to present a comparison between the desired effect that we have sought to achieve within the trials to determine its similarities with the desired 'use case.'

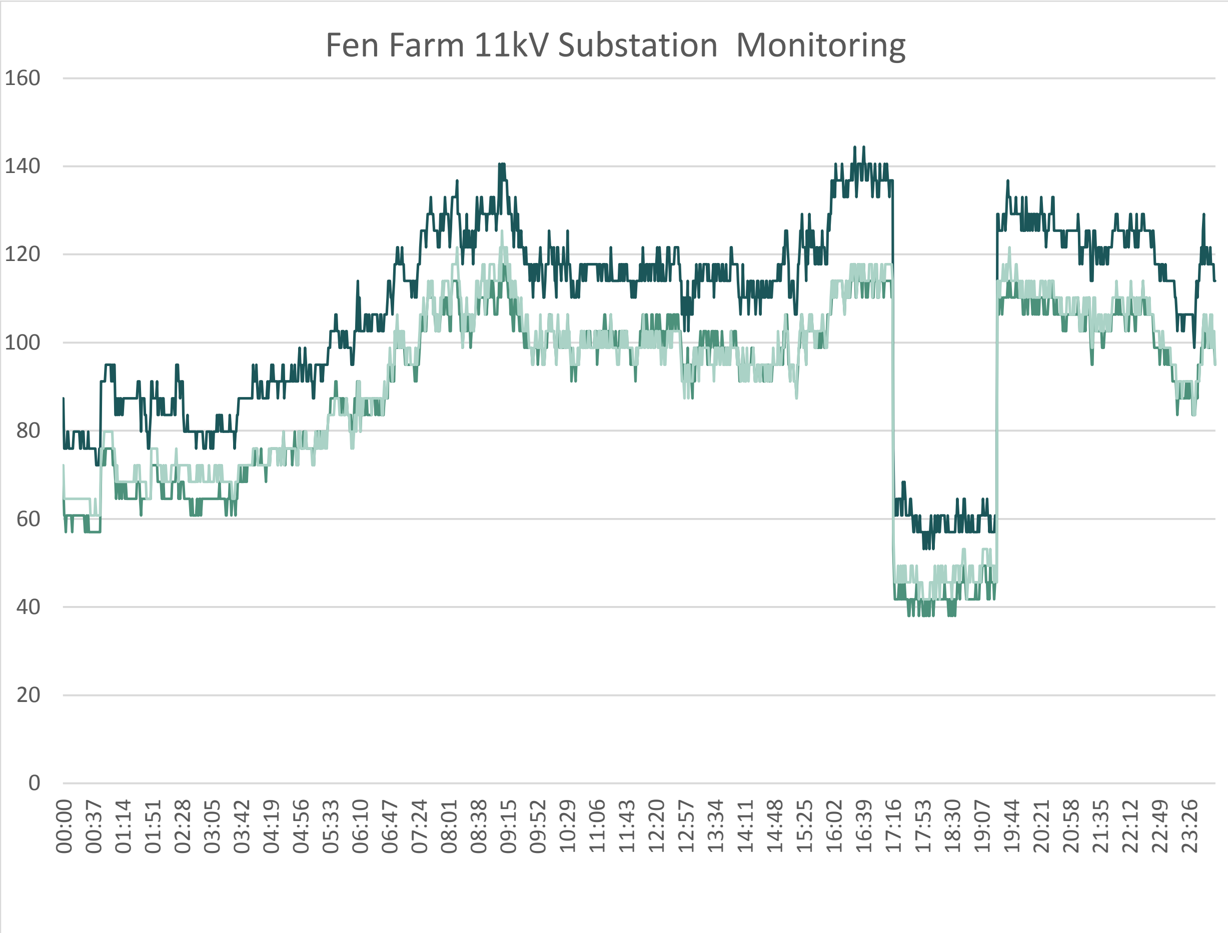


Figure 40 - 3 phase load readings for 24hr period including DSR event

The graph above is from a 24 period monitored at 1 minute intervals for a transformers located at the Fen Farm substation. This DSR event itself can be seen quite clearly between 16:30 and 18:30 when the participant site that is served from this feeder responds with its generation capacity of 1.5MW. The result is dramatic and unnecessarily large impact to manage the event, resulting in excessive payment that not only avoids the daily peak, but results in the lowest demand period of the day. This was true of all the 11kV sites that were being monitored during the events. It was also the case that on the few occasions when the participant incurred a failure or EoDs there weren't secondary participant sites to take over the event reduction and the impact at the substation was directly correlated with the success of the DSR event delivery by the participant. Increasing the number of participants that would be able to alleviate the load from the 11kV infrastructure is unfortunately limited by the small number of sites fed from the lower voltages.

This creates a clear disconnect between the proposed use case at 11kV which is the focus of Project FALCON and the SIM. In order to achieve a reliability and low enough risk profile from generators the DNO is likely to have to vastly over procure capacity or as would be more likely, at best there would only be a single participant and the risk of technique failure unacceptably high.

This is likely to change over the coming years as we see an increased level of participation being offered by load reduction sites. The market remains at an early infancy stage in terms of development of sites that understand, have capability and see sufficient incentive in participating in such schemes. Factors such as the smart meter roll out and more advanced service offerings that could combine multiple services to increase the value to the participant could be catalysts to increased capacity and site numbers willing to employ DSR opportunities.

12.12 Impact of Learning

The impact of the learning has beneficial throughout the various phases of the project, helping with not just capturing live data for the SIM as a primary objective, but also providing invaluable knowledge and experience to the industry in defining future uses and methods to deploy.

Although the majority of the learning outcomes were achieved during **(S1)** the results were of such impact that they highlighted many reasons as to why it was unlikely that an attractive use case would be formed. Primarily down to cost or reliability it would be unlikely that the SIM would ever determine DSR to be an attractive alternative method to conventional reinforcement. These might be determined by some observers as 'negative learning' and therefore the opportunity to capitalise on the early learning achievements and use these to modify the design of the DSR programme to improve the likelihood of a competitive use case. In order to achieve this it was necessary to extend the scope of the trial to engage the industry more widely through the formation of a Shared Services Group. In doing so the FALCON Commercial Trials ensured the trial fully acknowledged that DNO services require to be integrated amongst other DSR programmes. There are still several obstacles that exist within the market such as contractual exclusivity by the likes of National Grid's STOR programme that create an unnecessary competition that will force up the cost of DSR to the consumer. Through bodies such as The Shared Services Group and Ofgem's Work Stream Six the results of the trial will highlight some of the reform necessary to ensure that DSR is implemented at best possible value to the consumer who ultimately fund DSR programme budgets for both National Grid and DNOs.

The **(S2)** trial was equally successful in further advancing the learning that had already been achieved.

- Proving of a proposed separation of services between National Grid and DNO DSR programmes using the proposed timeline method from the Shared Services Group.
- Week ahead load analysis and dispatch
- Alternative programme parameters improved participant reliability
- Improved software and metering standards eliminated majority of administration burden

As with **(S1)**, **(S2)** could again be accused of establishing some important 'negative learning' that will most likely result in further work being required in order to develop DSR further before a suitable use case and market conditions improve its suitability for managing network constraints. One area in particular where this is likely to be the case is when the results of the trials are measured at 33kV rather than at 11kV which was the scope within the FALCON trials. When the results are measured at the increased voltage level, the combined impact of all the participants provides a profile shift very similar to that being sought at 11kV, but with added benefit that the multiple participants spread the risk and improve the expected reliability. This is likely to need further work and research but the value of the benefits are far greater due to the increased asset cost and importance of the higher voltage assets.

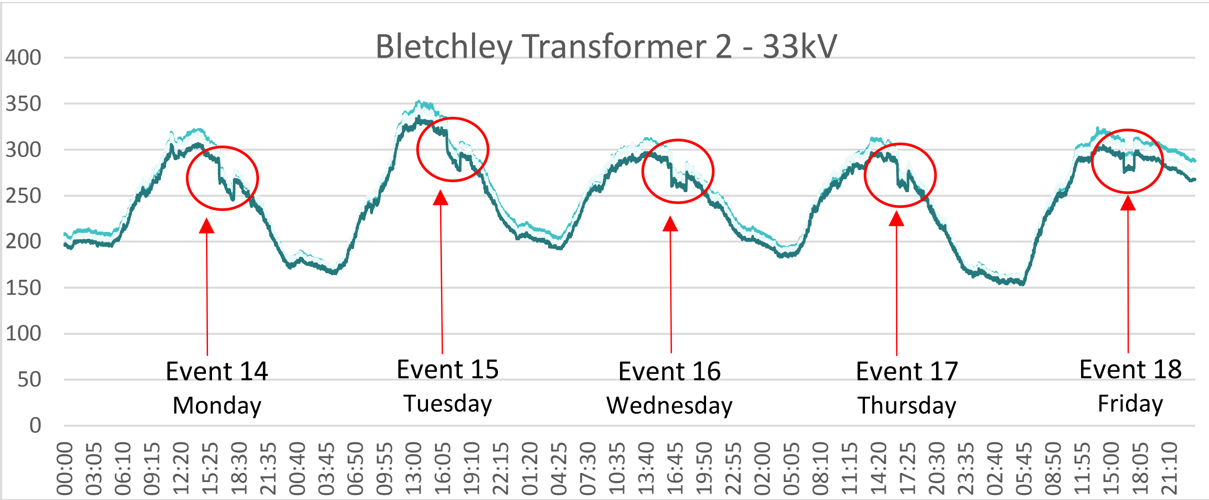


Figure 41 - DSR events monitoring at 33kV

The graph above provides a trace of the demand on one of the two 33kV transformers at the Bletchley bulk supply point over the week commencing 19th January 2015. As you can see from the size of the reduction it is of a more appropriate scale to the demand than at 11kV. Further work does require to take place to better determine the forecasting of the local peak demand profile which due to the nature of customer behaviour within the trial area resulted in local peaks occurring up to an hour in advance of the national peaks. In particular, event 14 coincided with one of the three national peak events used for triad charging which was successfully predicted and DSR event covered. To some extent this may be partially driven by customers' attempts to avoid triad charges by shifting demand earlier where they have any flexibility.

SECTION 13

Stakeholder Engagement and Learning Analysis

FALCON was a trial undertaken on the 11kV network in Milton Keynes. It encompassed two main approaches to be tested– engineering and commercial, as well as the development of a Scenario Investment Model (SIM). This document section was produced in conjunction with a team from The Open University (OU) and focuses on stakeholder engagement in the FALCON commercial trials – an innovative form of commercial technique that involved a Demand Side Response (DSR) trial.

The DSR trials were developed to investigate the use of innovative commercial arrangements to increase capacity on the 11kV network. In these commercial arrangements, standby or embedded generation and/ or customer demand (e.g. load reduction) was used to manage network constraints and consider the potential to defer or avoid network reinforcement.

Stakeholder engagement was a key part in FALCON ensuring that lessons learned from the trials were effectively captured and disseminated across relevant audiences. It was also crucial to obtain the stakeholder's perspective on the approaches adopted in FALCON and to understand how the FALCON work meshed with the way these organisations operate.

This learning analysis section presents the method and key findings from stakeholder engagement undertaken as part of the FALCON commercial trials. The report is structured as follows:

- Stakeholder analysis and engagement
- Method
- Findings
- Discussion and conclusions

13.1 Stakeholder analysis and engagement

This section presents the approach to stakeholder analysis and engagement adopted in FALCON.

13.1.1 Stakeholder analysis

The approach to stakeholder analysis in FALCON followed a project-centric logic in which stakeholders were identified in light of the project objectives (Friedman and Miles, 2006). As such, a stakeholder was defined as: "any group or individual who can affect or is affected by the achievement of the organisation's objectives" (Freeman 2010:46)[1].

[1] Freeman, R, E., 2010. Strategic Management: A Stakeholder Approach (digitally printed version). Cambridge University Press, UK.

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Following this definition, rationales for prioritising stakeholders are determined by the organisation's objectives. Prioritising stakeholders is therefore an ongoing process that is considered in light of what the organization is trying to achieve. Seen in this way, prioritisation of stakeholders can be organized in the following way (Frederick et.al., 1988):

1. Map stakeholder relations by assessing groups or individuals who can affect or are affected by the organisation's objectives
2. Map stakeholder coalitions (e.g. developing stakeholder categories)
3. Assess the nature of stakeholder's interests and power
4. Construct a matrix for prioritising stakeholders
5. Develop strategies for stakeholder engagement
6. Monitor changes in organisations objectives and shifting stakeholder coalitions

The stakeholder analysis undertaken by the OU team in collaboration with other FALCON team members (notably the Knowledge Workstream Lead and the FALCON Project Manager) broadly followed this approach. Having described the central components for prioritising stakeholders we now turn to modes of engaging key stakeholders.

13.1.2 Stakeholder engagement

The approach to stakeholder engagement in project FALCON broadly followed the ladder-model (Arnstein, 1969)[2]. This model, depicted in Table 15, illustrates the level of stakeholder participation: ranging from passive to active stakeholders. Using this model three discreet modes of engaging priority stakeholders were identified.

Table 15: Modes of engaging with priority stakeholders

Modes of engagement	Description	Methods
Informing/ Explaining	Release of information to stakeholders as a means to be open and transparent about the organisation's objectives. Information includes decisions taken by the organisation that may affect or be of interest to stakeholders. Related to this mode of engagement is explaining what the organisation is trying to achieve. This mode of engagement offers little opportunity for stakeholders to influence the organisation's achievements. Stakeholder participation in this engagement strategy is therefore labelled **passive**. Style of dialogue is often, but not necessary one-way.	Social media, reports, brochures, and project models
Consultation	This mode can be used in situations where feedback from stakeholders is needed. Stakeholders can be engaged to provide advice on the organisation's decisions and/ or objectives. This degree of stakeholder participation is called **involved** with two-way dialogues between the organisation and stakeholders established.	Interviews, focus groups and workshops

[2] Arnstein, S. R., 1969. A Ladder of Citizen Participation. Journal of the American Institute of Planners, V. 35:04

Modes of engagement	Description	Methods
Collaboration/ partnership	This mode can be deployed to achieve objectives that are mutually beneficial to both the organisation and the stakeholders involved. Stakeholders can be engaged through collaboration or partnership to bring particular skills or resources that are deemed useful to the organisation to achieve its objectives. This degree of stakeholder participation is here labelled **active** and is based on two-way or multi-way dialogues.	Strategic alliances, collaboration under contract

The approach selected to engage with identified stakeholders was consultation. In this approach, two-way dialogues between FALCON and its stakeholders were established. By selecting this dialogue-based approach of engagement feedback from priority stakeholders involved in the commercial trials could be gained.

Stakeholder engagement has been an ongoing process in FALCON and proceeded iteratively. Consequently, stakeholder engagement was modified as project objectives were refined and new stakeholders joined the project.

13.2 Method

This section describes the method used for data collection from priority stakeholders and subsequent data analysis.

13.2.1 Data collection

A qualitative approach involving semi-structured interviews was the method identified to engage with priority stakeholders involved in the commercial trials. This method was selected since it enables two-way dialogues between the interviewer and interviewee, and is therefore consistent with the consultation mode of stakeholder engagement.

Interviews with priority stakeholders took place during **(S1)** and **(S2)** commercial trials. The stakeholder interviews were based on a set of themes and questions (see appendix 1), which was prepared for each season of the trials. Importantly, the semi-structured approach also enabled further questions to be asked as interesting lines of enquiry opened up during the interview. This allowed interviews to proceed in an open-ended and flexible manner (Robson, 2011).

An interview guide (see section appendix 1) was developed to enable data to be collected from priority stakeholders. The guide included:

1. A list of interviewees
2. A set of prepared interview themes and questions
3. An interview schedule

This interview guide was consistent with the semi-structured approach and was developed in an iterative fashion. Interview themes and questions were developed for the first round of interviews **(S1)**. Findings from the first round of interviews informed subsequent interviews **(S2)** until the trials were completed. The interviews with priority stakeholders involved in the commercial trials were recorded and transcribed for analysis.

13.2.2 Data analysis

The purpose of data analysis was to interpret the feedback gained from the stakeholder interviews and identify lessons that can be learned about the commercial trials from these stakeholders. Since data collected via interviews consist of words and narratives that are rich and complex, we followed Miles and Huberman's (1994)[3] method to reduce data into something that is manageable and to enable a meaningful interpretation to be made. A flexible template approach was selected for this purpose, which consists of three interlinked activities:

- **Data reduction**: the process of reducing a large amount of data into something that is manageable.
- **Data display**: presenting data in a meaningful way.
- **Drawing conclusions**: identifying what the data has to say.

Data analysis followed this template approach. Analytical categories were developed to allow the large amount of data to be reduced and clustered into key themes. The analytical categories were consistent with the interview themes. New themes emerged as data analysis proceeded.

A table format was used to present data in a meaningful way,. Conclusions were subsequently drawn from these tables.

13.3 Findings

This section presents the results of the stakeholder analysis and feedback gained from the interviews with priority stakeholders undertaken as part of the commercial trials **(S1)** and **(S2).**

13.3.1 Stakeholder analysis

A stakeholder analysis was undertaken by the OU team. A plurality of stakeholders were identified from ongoing review meetings with the Knowledge Workstream Lead, an internal FALCON workshop and a review of smart grid literature, e.g. policy and industry reports.

[3] Miles, B. M., and Huberman, A. M. 1994. *Qualitative Data Analysis* (2nd Edition). Sage Publications Ltd. London, UK

While the stakeholders are multiple and diverse, we have identified key stakeholder groups, whose nature and characteristics were of particular relevance to FALCON. The results of the stakeholder analysis is summarised in Table 16.

Table 16: Stakeholder groups and priority stakeholders identified in project FALCON

Stakeholder Groups	Description of stakeholder groups	Priority stakeholders
Policy/ Regulators	Actors involved in developing policies and regulations to promote a secure, affordable and low carbon energy supply. Ofgem through the LCNI provides financial support to FALCON and is interested in the learning outcomes from this project to understand its impact on current and future regulatory development and to promote knowledge sharing within the electricity industry.	DECC, Ofgem (LCNI)
System/ Distributor	Actors who own and maintain electricity network infrastructure, including transmission and distribution networks. These stakeholders have a profound interest in the learning outcomes from Project FALCON.	National Grid; DNOs; ENA and ENFG
Demand Side Response Market	Actors involved in commercial arrangements involving demand side response measures. Aggregators are both participating in the commercial trials in Project FALCON and are interested in the knowledge gained in these trials.	Aggregators
Customers	Actors that use electricity. Industrial and commercial Customers participate in Project FALCON and/ or have particular interest in the knowledge gained from these trials.	Industries in the trials region
Milton Keynes Community	Actors in the community in which the trials are taking place with particular interest in the knowledge gained in these trials.	MK Council Low Carbon Steering Group; Transport Catapult; Local Academia
Technology providers	Actors involved in developing and providing technologies used in the FALCON trials or other smart grid projects, and have a particular interest in the knowledge gained in these trials.	Alstom, Aston University, GE, Cisco
Internal	Individuals or departments within the WPD organisation supporting Project FALCON and/ or have particular interest in the knowledge gained from the project.	Future Networks Team; Policy; Distribution

This stakeholder analysis was used to categorise stakeholder groups involved in the DSR trials in the FALCON project. For the DSR trials, priority stakeholders included both those actors participating in the trials and actors relevant to the trials, but were unable to participate. An overview of priority stakeholders identified for the commercial trials **(S1)** is provided in Table 17.

Table 17: Priority stakeholders identified for the commercial trials (S1)

Stakeholder category	Description
Aggregators participating in the trials	Those actors who participate in the commercial trials through the aggregation service they provide.

Stakeholder category	Description
Aggregators who were unable to participate in the trials	Aggregators who were invited to participate in the trials but were unable to.
Participating firms	Industrial and Commercial customers who participate in the trials directly (i.e. not via an aggregator).
Internal stakeholders (WPD)	Actors and/or functions within WPD, e.g. the control room.

Following commercial trials **(S1)**, a series of interviews were conducted with these priority stakeholders. The purpose of these interviews was to gain feed-back from stakeholders' perspective on and experience from the trials **(S1)** and to enable multiple perspectives on the commercial trials to be gained

13.3.2 Commercial trials (S1)

This section presents the results in Table 18 from the interviews conducted with aggregators participating in the commercial trials **(S1)**.

Table 18: Aggregators participating in the commercial trials (S1)

Interview Topics	Aggregators participating in the commercial trials (S1)
Information about the stakeholder (e.g. what they do)	Specialised in commercial demand response services involving both generation and load reduction. Services are provided for the National Grid and the Short Term Operating Reserve (STOR) programme, as well as other demand response programmes.
What were you asked to do in the FALCON trials?	Aggregator firms provided generation. Existing relationships with clients in the FALCON trial region (i.e. Milton Keynes) enabled participation. The established relationship with the client via the STOR service was transferred to the FALCON trial. Other clients were sought in the region, but it was noted by the aggregator firms that there was too little time to establish new relationships for this trial. Moreover, the investment needed to complete the necessary arrangement with clients to take part in the trial, may not be financially viable considering it is a trial and not an enduring programme.
What did you consider to be the benefits/costs of participating?	The trial presented an opportunity to take part in the development of a new demand response programme. More specifically, this includes the innovative activities of the trial and an opportunity to gain knowledge and understanding of what is going on in this part of the energy sector. Other benefits include the financial aspect and to reinforce customer relationship. Benefits for clients include (1) financial aspects, and (2) opportunity to enhance company profile, including aspects of social responsibility in terms of making a contribution towards helping to resolve strategic energy challenges. Cost of participating in the trial for the aggregator firm and its client include management commitments to set up the arrangement and operational costs related to the trial.

Interview Topics	Aggregators participating in the commercial trials (S1)
Why did you participate?	Project FALCON is seen as an opportunity to take part in the innovative activities of the trials and to learn more about the potential of commercial demand response programmes at a distribution level.
What is your view on the contract in comparison with similar schemes?	The contract was viewed as clear and easy to understand for both the aggregator firm and their clients. It was noted that while the contract is useful for a trial, it is not seen as robust enough for a long term service e.g. STOR.
What is the difference to working with other demand response schemes	While the National Grids STOR is an established programme, the demand response scheme being trialled in FALCON may open up opportunities for new forms of arrangements. The contractual arrangement of STOR is more robust in terms of ensuring performance of aggregators and their clients. This includes both utilisation-payment and availability-payment so that clients get paid to be on stand-by. Moreover, penalty arrangements are established if clients and/or aggregator fail to perform when required. The FALCON trial only offers utilisation payment. Being paid only for utilisation is argued not to be cost-effective in the long term for clients. The absence of penalty may also run the risk of attracting clients and aggregators that may not perform when required. STOR dispatch service is automated and the FALCON trial is not.
What if anything would you like to change for another trial?	To have some degree of automation would be useful for future trials. The payment structure may need to change to facilitate the engagement of clients for future trials. Financial aspects to be considered is the investment needed for clients who are new to demand response programmes. Such payment structure could include both availability-payment and utilisation-payment.
Do you see any opportunities to work with your clients for demand reduction rather than generation?	While there are opportunities for demand reduction, the challenge is to articulate the value of reducing electricity load as part of a demand response programme. For example, If a site can reduce its load they may do it permanently.
What are the priority issues that needs to be addressed in order to enable commercially driven demand response techniques?	To explore the potential for various demand response programmes to co-exist and be compatible. For example, one approach may include development of demand response programme at a distribution network level that can work in parallel with demand response programme (e.g. STOR) at national level. Moreover, to ensure that demand response assets can be used in an optimal and intelligent way.

From the results in Table 4 we identified the following insights on the DSR trials from aggregators participating in the commercial trials **(S1).**

- Overall, the commercial trial presented aggregators with an opportunity to engage in innovative activities including the development of a new DSR programme. The role of aggregators in these trials was to provide DSR from client's sites. Those aggregators who had established relationships with clients situated in the trials region (e.g. via the STOR programme) were able to recruit these clients for the FALCON trials.
- While aggregators provided DSR from clients with generation capacity, they were unable to identify sites that could provide DSR by reducing electricity demand.
- The commercial arrangements of the FALCON trials received positive views in terms of the contract developed for this trial. The contract was viewed by participants as clear and easy to understand and suitable for a pilot DSR scheme.
- Differences between the pilot DSR scheme developed in FALCON and other DSR programmes (e.g. STOR) was identified and include 1) contractual arrangement and 2) geographical context.
- Aggregators noted that DSR on the distribution network needs to be developed so that it can work in parallel with other DSR programmes, notably STOR.

Results from the interviews conducted with aggregators who were unable to participate in the commercial trials **(S1)** are presented in Table 19.

Table 19: Aggregators who were unable to participate in the commercial trials (S1)

Interview Topics	Aggregators unable to participate in the commercial trials (S1)
Information about the stakeholder (e.g. what they do)	Specialised in commercial demand response services involving both generation and load reduction. Services are provided for the National Grid and the Short Term Operation Reserve (STOR) programme.
What were you asked to do in the FALCON trials?	Aggregator firms tried to participate either by providing generation or demand reduction
What did you consider to be the benefits/costs of participating?	Benefits ranged from an opportunity to try novel measures for demand reduction through to an opportunity to explore the potential of expanding the aggregator market at distribution network level.
Why were you unable to participate?	Aggregator Firms have developed services for the National Grid and the STOR. These services are developed in such a way that they are suitable for the National Grid and not for DNOs. Hence, a mismatch is noted between the services that certain aggregator firms provide and the service required by the FALCON commercial trials. The nature of the commercial trials in terms of trial period (two winter trials) and reward offered to participate in the trial, does not always justify the installation costs required to deploy demand response measures for the trial. Moreover, the commercial trials required aggregator firms to build relationships with Industrial and Commercial customers in Milton Keynes. However, building such relationships can take time and require efforts that may not be justified considering that it is a trial and not an enduring programme.
What is the difference to	Geographical location: Aggregators who provide a service to the National

Interview Topics	Aggregators unable to participate in the commercial trials (S1)
working with other demand response schemes?	Grid and the STOR scheme can link any asset (e.g. load shedding or generation) across the UK. DNOs, on the other hand, are constrained by the region or city in which they operate. STOR is established: Services offered by aggregators are developed in such a way that they fit the STOR scheme and the auction at which such services can be sold/bought. A market for demand response equivalent to the STOR scheme is not yet established at electricity distribution level. Time and size of response: Time of response including the period through which the service required by STOR is needed tends to be relatively quick and short (e.g. minutes). The size (e.g. kW) of the service matters too.
What if anything would you like to change for another trial?	Aggregators are interested in participating in another trial. Additional consultation may, however, be necessary to address any dissimilarities between the design of the trials and the services offered by aggregator firm.
Do you see any opportunities to work with your clients for demand reduction rather than generation?	Aggregators see an opportunity to develop services around demand reduction. While many aggregator services include generation, the potential for load management is to some extent underdeveloped. Commercial trials such as FALCON may provide an opportunity to further investigate the potential for load management involving demand reduction.
What are the priority issues that need to be addressed in order to enable commercially driven demand response techniques?	Engaging with customers: Knowledge about Industrial and Commercial customers, including how to engage with such customers, is important to address.

From the results in Table 19 we identified the following insights on the DSR trials from aggregators who were unable to participate in the commercial trials **(S1).** The reasons for aggregators not being able to participate in the FALCON trials was identified as follows

- The DSR trials developed in FALCON was a trial that expanded over 2 seasons. The reward offered to participate in the trials did not justify the cost of establishing new relationship with clients.
- The DSR services developed by some aggregators are suitable for the National Grid, but cannot be deployed to provide DSR for a DNO.

Results from a customer who participated directly (i.e. not via an aggregator) in the commercial trials **(S1)** are presented in Table 20.

Table 20: Customer participated directly in the commercial trial (S1)

Interview Topics	Customer participated directly in the commercial trials (S1)
Information about the stakeholder (e.g. what they do)	The customer is a firm specialised in water supply and waste water treatment. Energy is one of the highest operating costs. A large proportion of energy is used for waste water pumping and aerating processes. The firm is a STOR service provider working directly for the National Grid.

Interview Topics	Customer participated directly in the commercial trials (S1)
What were you asked to do in the FALCON trials?	To provide generation from one of the firm's site when required. A stand-by generator was used for the purpose of this trial.
What did you consider to be the benefits/costs of participating?	The benefit of participating in the trial was to be involved at an early stage in the innovative activities. This was seen important considering that demand response at a distribution network level is novel with a potential to grow. Moreover, development of demand response programmes provide firms who use large amount of electricity with an opportunity to make a contribution towards resolving some of the national energy challenges, e.g. security of electricity supply. In terms of cost, it was noted that key individuals within the firm's organisation were required to commit time to facilitate and operate the trial.
Did your participation provide the benefits you expected?	The firm's participation in the trial provided the benefit they expected. However, it was noted that the time it took to become active in the trial was longer than anticipated.
What is your view on the contract in comparison with similar schemes?	The firm found the contract easy and straight forward. The contract was found to be similar to the contract they have with the STOR programme.
What if anything would you like to change for another trial?	The firm did not see any reason to change anything for another trial.
Consider a future when all electricity contracts included the option allowing I&C customers to be paid for generating and/or reducing electricity. Would this open up opportunities for your organisation?	The firm is participating in those demand response programmes provided by the National Grid that are suitable for their type of operations. It was noted that stand-by generators that are owned by the firm and can be used for demand response programmes, may not be designed to run frequently throughout the year. Thus, if more options are made available to participate in demand response programmes, it may reduce the operational life of stand-by generators.
What are the priority issues that needs to be addressed in order to enable commercially driven demand response techniques?	Demand response programmes must be financially viable. The benefit of participating in the STOR programme is the availability-payment they offer. To make sure that demand response programmes at distribution network level can work without being in conflict with other programmes.

From the results in Table 6 we identified the following insights gained from a customer who participated in the commercial trials **(S1).**

- The motives identified by the customer to participating in the trials include 1) to take part in the development of a DSR trials on the distribution network; and 2) DSR is of strategic importance for the business, e.g. Corporate Social Responsibility and energy management.

- The customer noted that the contract was clear and easy to understand and suitable for a trial. Going forward, it was noted that DSR on the distribution network should develop in such a way it can work in parallel with other DSR programmes, e.g. STOR.

Results from an internal stakeholder, the control room at Western Power Distribution (WPD) is presented in Table 21.

Table 21: Internal stakeholder, the control room at Western Power Distribution

Interview Topics	Control Room
Information about the stakeholder (e.g. what they do)	The control room control the network and facilitates planned work. Practice of control include monitoring the network for issues that require a response to ensure that electricity is supplied to customers in a safe, efficient and effective manner. Planned work include the development and implementation of long term plans to maintain and/or reinforce the network.
What were you asked to do in the FALCON trials?	The control room were initially asked by project proponents to engage with customers during the trials. However, considering that this was a trial it was noted that any contact with customers should be managed within the trial and not by control room staff. The role of the control room was therefore to control the state of the network during the trials. This required the shift manager to monitor the network in which the trials was taking place. It was noted that a procedure was needed that detailed what the shift managers were going to do when the trials were going live.
What is your view on the contract in comparison with similar schemes?	The control room has existing relationships with I and C customers who provide generation and/or load reduction when required.
What needs to be done to enable demand response to become business as usual?	It is recognised that the commercial trials cannot easily be deployed from its current form into business as usual. Implementing commercial techniques involving demand response require significant change in how the control room operate. Commercial arrangements involving demand response measures may usefully be implemented so that it becomes an integrated part of the system that is already in place. One approach to engage customers in a commercial arrangement involving demand response, could include a commercial constraint with automated control.
What did you consider to be the benefits/costs of participating?	Demand response can provide an additional capability to operate the network. While asset replacement and reinforcement measures are necessary, commercial arrangements could be added to the way the control room operates.
What are the priority issues that needs to be addressed in order to enable commercially driven demand response techniques?	A priority issue from a control room perspective is to ensure that demand response measures can be deployed in a reliable and safe manner. The reliability of customers' response (load reduction or generation) when requested by the control room to do so is of importance.

Interview Topics	Control Room
	It is recognised that the commercial trials in its current form involve a few participating customers. Deploying commercial demand response techniques on a larger scale may require a different arrangement to engage customers to deploy demand response measures. This could include automated arrangements.

From the results in Table 20 we identify the following insights on the DSR trials from the control room at WPD.

- The control room was invited to participate in the FALCON commercial trials to have an active role in these trials to engage with customers. However, because this was a pilot DSR scheme contact with customers should be managed within the project. Control room staff monitored the state of the network during the trials.
- The control room are familiar with the concept of DSR since relationships with large electricity using customers are already established. These customers can be called upon to provide DSR when required by the control room.
- For the DSR trials to become viable from the control room's point of view it was noted that it has to be developed in such a way it can be integrated with how the control room operates. DSR must be deployed in a safe and reliable manner, which may require relationships with customers that allow for automated form of DSR.

13.3.3 Summary and highlights gained (S1)

This section presents a summary and highlights from stakeholder interviews conducted during the commercial trials **(S1).** Insights gained from interviews conducted in **(S1)** provided multiple perspectives from various stakeholders involved in the trials.

- **For aggregators** the DSR trials was seen as an opportunity to be involved in the development of a new DSR programme. Those aggregators with established relationships in the trials region were able to participate in the trials. However, those aggregators who tried to recruit new clients for the trials were unable to do so. It was noted that building new relationships with clients to provide DSR can be costly and take time to establish, and may therefore not be justified considering it was a trial. In terms of the commercial arrangement it was noted by aggregators that DSR on the distribution network must be developed in parallel with other DSR programmes, notably STOR.
- **For customers** the DSR trials offered an opportunity to take part in the development of a new DSR programme. Overall, DSR is of strategic importance for the business in terms of CSR and energy management. However, to participate in DSR on the distribution network, it was noted by the customer that DSR at this level must work in parallel with DSR on the national grid level.
- **For the control room** it was noted that DSR on the distribution network must be deployed in a safe and reliable manner, which may require automated arrangements with customers.

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Stakeholder feedback also provided insights on differences and similarities between FALCON and other DSR programmes, notably STOR. The similarities with STOR includes:

- The FALCON commercial trials were designed in such a way they enabled aggregator firms with experience of deploying demand response measures for STOR to participate.
- Aggregators who were able to participate were those who had established relationships via the STOR programme involving customers situated in the region in which the trials were taking place. Aggregators could transfer their arrangement from STOR to the FALCON trials.
- The customer participating directly in the FALCON trials was familiar with the demand response programme via their part in the STOR programme. Experience from the STOR programme was found transferable to demand response at distribution network level.

Having identified the similarities, the following differences were identified:

- The National Grid's STOR programme is nationwide, while the demand response programme being trialled in project FALCON is restricted to a particular geographical region (i.e. Milton Keynes).
- Aggregator firms have developed services that are suitable to the National Grid's STOR programme. While some services are transferable, others may not be easily transferred to the way Distribution Network Operators (DNOs) operate.
- The contractual arrangement in the STOR programme involves both utilisation and availability payments, including penalties when pre agreed demand response parameters are not met. Project FALCON offered utilisation payment only.

Priority issues identified from stakeholder feedback in **(S1)** that required further attention in order to enable commercial DSR at distribution network level include:

- **Contractual arrangement**: while the contractual arrangement was seen by participants as useful and valid for a trial, a more robust contractual arrangement is needed for developing an enduring demand response programme at distribution network level. This may include similar aspects that are established in the STOR programme, e.g. availability payment and penalty arrangement.
- **Automation**: it was noted by several key stakeholders that a more enduring DSR programme may require some degree of automation.
- **Compatibility:** It was noted by several aggregator firms that it may be useful to explore the potential for various DSR programmes to work in parallel to ensure optimal use of assets can be used for such measures.
- **Reliability**: Any DSR programme has to work effectively and efficiently to be reliable for all stakeholders involved. This includes, but is not limited to: (1) commercial viability to enable the business case for demand response, (2) performance of service providers when required.
- **Engaging customers**: DNOs may have to learn how to engage with customers to enable a commercial demand response programme at distribution network level. There are several routes to engage customers such as (1) establishing direct relationship, (2) via aggregators or (3) other third party.

This feedback from stakeholders identified a need for constructing further dialogue with key stakeholders in designing and developing a robust DSR programme at distribution network level. Key stakeholders include, but may not be limited to:

- **Demand side actors** (e.g. customers) suitable for local demand response measures. Here we refer to demand side actors situated within the geographical area of the distribution network operator; and who have assets that can be used for generation and/or type of operations that allow for load reduction when required.
- **Aggregator firms** that have knowledge and experience about DSR and can link demand side actors with a DNO to enable DSR on the distribution network.
- **The National Grid** is a key actor to engage in dialogue around developments in the DSR market in order to avoid conflict with the STOR programme and the Triad scheme.
- **Other DNOs** in the UK and/or overseas with experience of deploying demand response measures may be useful to engage in dialogue with for the purpose of knowledge sharing.
- **Regulator:** dialogue with the regulator of the electricity market (Ofgem) around deploying demand response measures may be of importance to develop an enduring programme at distribution level.

A number of discussion points was identified from stakeholder engagement in **(S1)** to explore further. These discussion points include:

- How to engage customers to participate in a DSR programme at distribution network level. This includes aspects of commercial viability to make the business case for demand response measures.
- The role of the DNO in commercial demand response programme. This may include practices of the control room through to development of commercial arrangements.
- Explore the potential for various DSR programmes to co-exist.
- How relevant institutions (e.g. regulations) have to change or adapt to emerging demand response programmes.

Following **(S1),** the trials were modified. The modification included the following:

- further incentive was given to participants to provide DSR via load reduction
- notification of dispatch was altered from 30 minutes to a week in advance notice
- a smart meter was installed on the sites of participating firms to monitor the effect of their response on the distribution network

The highlights and discussion points identified from insights gained **(S1)** and modification of the commercial trials for **(S2)** influenced development of interview guide (see section appendix 1). New themes and questions for interviews included:

- Performance and reliability: This was a new interview theme and involved questions to stakeholders (e.g. aggregators and participating firms) about ways to ensure that DSR is provided.
- Comparing generation and load reduction: This was a new theme by which questions was asked about the differences and similarities between DSR in the form of generation and load reduction
- Contractual arrangement: This theme was a focus in **(S1).** However, questions about the contract was not asked in **(S2)**
- What if anything would you like to be changed for another trial: this question was asked following **(S1),** but not in **(S2)**
- Developments in the DSR market and the role of stakeholders: This was a new interview theme and question identified for interviews undertaken as part of **(S2)**

13.3.4 Commercial trials (S2)

Stakeholder interviews for the second set of trials **(S2)** were conducted with the same stakeholder groups, namely aggregators, firms participating in the trials and internal. However, stakeholders engaged for an interview changed between **(S1)** and **(S2).** More specifically:

- Aggregators: Stakeholder interviews undertaken with this stakeholder group focused on aggregators participating in the trials. Aggregators who were unable to participate were not interviewed in **(S2).** New aggregators had joined the trials in **(S2)** and were interviewed for the first time. Other aggregators who participated in **(S1)** and **(S2)** were also interviewed.
- Firms participating: Stakeholder interviews undertaken with this stakeholder group was expended and included two additional firms one of which had joined the trials in **(S2).**
- Internal: rather than stakeholder interviews, an internal workshop was undertaken with members of the FALCON team involved in the commercial trials. A second interview was also conducted with the Future Network Manager at WPD.

The results from interviews with aggregators participating in **(S2)** of the commercial trials are presented in Table 22.

Table 22: Results from interviews with aggregators participating in (S2)

Themes for analysis	Results from interviews with aggregators participating in (S2)
Business activities and core skills	Firms specialising in DSR, an energy capacity service offered to utilities, e.g. the National Grid. Core skills include 1) Understanding the user cases for DSR, 2) Establishing relationship with energy partners to provide DSR, 3) Co-developing DSR programmes, and 4) development and use of control and monitoring equipment to manage DSR.
Motives for participating in the trials	The LCNI projects led by DNOs, including FALCON, may provide commercial opportunities and growth in the DSR market.

Themes for analysis	Results from interviews with aggregators participating in (S2)
Role in the trials	Aggregators had an intermediary role in the trials, and were asked to provide distributed generation and/or load reduction from their energy partner's sites as requested by the FALCON trials. Aggregators were not able to identify adequate sites for load reduction for the FALCON trials. DSR from generation were successfully supplied.
Comparing generation with load reduction	Since DSR in the form of load reduction involves turning equipment down or off, it must be carefully managed as it may affect client's business operations. An advantage of load reduction for the energy partner is the knowledge they may gain about their energy consumption from undertaking a site survey. However, energy consumption identified for load reduction may lead to permanent reduction, which limits the capacity available for DSR. DSR in the form of generation is therefore favoured because it can be managed with limited impact on clients' business operations. An advantage for energy partners using generation is the opportunity it presents to test and maintain electricity standby and backup equipment.
Performance reliability	To ensure performance reliability of DSR the following strategies can be deployed by an aggregator: 1) develop and maintain a capacity buffer, 2) develop engineered solutions to monitor client's site and performance associated with DSR, 3) develop and maintain a technology platform to manage DSR services. Aggregator firms also noted that service purchasers (e.g. the National Grid and DNOs) should offer sufficient payment for DSR services to ensure necessary investment, and establish enduring DSR programmes to allow for long-term DSR services and ensure payback on investment. One aggregator noted that the installation of a smart meter owned by the DNO made it difficult for the aggregator to monitor DSR activities at their client's site.
Comparing FALCON with other DSR programmes	Notification of dispatch: This was altered from a 30 minute notification in the first set of trials to a week in advance notice to participating firms and aggregators. This feature allows aggregators and participating firms to plan DSR activities and integrate with other programmes. Other DSR programmes tend to have much shorter time interval between requests and dispatch, e.g. minutes. Mode of dispatch: the FALCON trials do not have automated dispatch, which is a common feature in more enduring DSR programmes involving a large number of service providers. This is reflective of the trials nature and automation would likely come with any transferral into Business as Usual (BAU). Payment structure: the FALCON trials offer payment for utilisation only, whereas many other DSR programmes offer payment for both availability and utilisation. Allow shared services: The FALCON commercial trials were designed in such a way as to allow aggregators and their energy partners to participate in other DSR programmes, e.g. STOR.
Future developments in the DSR market and the role of aggregators	Commercial opportunities: Aggregator firms are seeking commercial opportunities for DSR services across the energy sector including the National Grid, DNO's, retail and energy trading. DSR led by DNO's may offer commercial opportunities and growth in the DSR market in the near future. User cases: The potential user cases for DSR include: 1) reserved capacity to ensure consistency of power supply, 2) balancing renewable electricity

Themes for analysis	Results from interviews with aggregators participating in (S2)
	generation, 3) managing network constraints, 4) avoid or defer network reinforcement, 5) managing network connections involving load control, and 6) energy trading. Shared services (or not): the DSR market can either become more competitive and exclusive (e.g. one asset for one DSR programme) or become more complementary and inclusive (e.g. one asset for several programmes).

From the results in Table 22 we identify the following insights on the DSR trials gained from aggregators participating in **(S2)** of the commercial trials.

- In **(S2)** aggregators were further incentivised to provide DSR by reducing electricity load at client's sites. However, DSR from load reduction was not achieved by an aggregator in **(S2).** The main reason for not being able to provide DSR from load reduction was because relationships established with clients situated in the trials region did not have adequate loads to turn down as requested by the trials.
- Aggregators participating in the trials were positive about the change of dispatch notification from 30 minutes to a week in advance notice. This allowed aggregators and their clients to plan DSR activities in other programmes, e.g. STOR. However, one aggregator noted that the smart meter installed by the DNO on their client's site made it difficult for them to monitor DSR activities at this site.
- For developments in the DSR market aggregators noted that DSR can either become more competitive and exclusive (e.g. one asset for one DSR programme) or become more complementary and inclusive, e.g. one asset for several programmes. Aggregators expressed positive views on the shared service, which would allow them to engage their clients in several DSR programmes rather than one.

Results from firms participating in **(S2)** of the commercial trials are presented in Table 23.

Table 23: Results from interviews with firms participating in (S2)

Themes for analysis	Results from interviews with firms participating in (S2)
Business operations and energy consumption	Firms who participated in the FALCON trials are characterised as large electricity users with very different business operations, e.g. a water utility, a university and a district heating scheme. These firms have embedded and distributed electricity generation on their sites (e.g. diesel generators, Combined Heat and Power units), which can be used for DSR.
Motives for participating in the trials	Four motives for participating in the FALCON trials were delineated from the interviews with participating firms; these include: financial aspects, Corporate Social Responsibility (CSR); and energy management. Financial aspects: DSR can help firms to reduce cost associated with energy and/ or provide an additional revenue stream. For example, one firm noted that DSR (e.g. FALCON trials) provides an important income to cover the cost of investing in distributed electricity generation. CSR: engaging in DSR programmes can help firms with their CSR agenda. For example, one firm who is a large electricity user noted that engaging in DSR programmes allows them to support national energy supply and low carbon initiatives. Energy Management: DSR can help firms understand energy consumption,

Themes for analysis	Results from interviews with firms participating in (S2)
	identify energy saving measures and reduce their carbon footprint. DSR developments: Participating firms view the FALCON trials as an opportunity to learn about DSR, to engage in a novel DSR development, and build new forms of relationships with WPD. For example, one firm noted that participating in the FALCON trials may provide the opportunity for participation in future trials and/ or enduring DSR programmes on the distribution network.
Role in and experience of the trials	The role of participating firms was to provide DSR by using their own generation (e.g. CHP, diesel generator) and/or via load reduction (e.g. turning pumping down or off). Overall, the experience of the trials was good. More specifically, firms familiar with DSR noted that the contract was clear and concise making it easy to understand and adopt. Moreover, the one-week notice was useful to those firms participating in DSR programmes (e.g. STOR) or other utility schemes, e.g. TRIAD and DUoS. The majority of the firms provided DSR via generation. One firm managed to provide load reduction. The nature and characteristics of business operations was identified as an important factor to allow for DSR, load reduction in particular. For example, one firm tried to provide DSR via load reduction but was unable to identify sufficient capacity in time without compromising core business operations. The majority of the participating firms provided DSR via an aggregator. The reason for this was that firms had established relationships with aggregators. For example, one participating firm noted that it was convenient to provide DSR via an aggregator since DSR events occurred outside office hours. However, the firm also noted that dealing directly with a DNO rather than an aggregator would be preferred in future trials. Firms new to DSR noted that implementing DSR on the site required consultation with multiple departments to address contractual and technical aspects.
Future development of the DSR market and the role of participating firms	Overall, firms participating in the trials have an interest in DSR developments and participating in future programmes. Participating firms noted a number of implications for further involvement in DSR; these includes: 1) load reduction can be provided as long as it does not compromise core business activities; 2) providing DSR via generation may lead to a decline in the lifetime of embedded generation (e.g. standby and backup generators); and 3) there is a lack of information about the DSR market for firms.

From the results in Table 23 we identify the following insights on the DSR trials from firms participating in **(S2)** of the commercial trials.

- Overall, firms participating in **(S2)** of the commercial trials expressed positive views on the contract and interest in further developments of DSR on the distribution network. For example, the change from 30 minutes to one week in advance notice was appreciated by firms since this allowed them to engage in other DSR activities.
- Motives identified by firms for participating in the commercial trials included 1) financial reward, 2) energy and carbon management, and 3) CSR in terms of supporting national energy supply and development of low carbon energy networks.

- Firms noted that implementing DSR into the business can take time, which may delay participation in the trials. For example, the implementation of DSR at one site required engagement with multiple departments in that firm. Moreover, DSR may interfere with core business operations, load reduction in particular, making it difficult for a firm to provide DSR.

Results from an interview with an internal stakeholder is presented in Table 24

Table 24: Results from an interview with an internal stakeholder (S2)

Themes for analysis	Results from an interviews with an internal stakeholders (S2)
Role within WPD and/ or the FALCON trials	Future Networks Manager
Purpose of the trials	Across the FALCON project, the purpose was to develop and test solutions today that can defer traditional network reinforcement and resolve network issues in the future.
Key lessons emerging from the commercial trials:	Demand Side Response (DSR) on the 11kV network may not be a viable for a DNO because the 11kV networks tend to have few clusters of large non-domestic electricity users and organisations with standby generation on site. This does not mean that FALCON DSR is unattractive to WPD. Rather, more testing needs to be done on the 33kV and 132 kV networks. At this network scale, DSR capacity can be sourced from a greater geographical area with a higher number of large non-domestic electricity users including standby generators. Thus, network scale and geographical area matters to DSR developments on the distribution networks. More testing may also involve other routes to access DSR services (such as direct relationships with firms with DSR capacity) rather than going via an aggregator.

From this interview with an internal stakeholder we identify the following insights:

- DSR on a higher network scale (e.g. 33kV) may be more commercially viable, and further trials may explore possibilities to establish direct relationships with customers.

13.3.5 Summary and highlights from (S2)

This section presents a summary and highlights from stakeholder interviews and the internal workshop conducted during **(S2)** of the commercial trials. Insights gained from interviews provided further insights on the perspective and experience of aggregators and firms participating in the DSR trials developed in FALCON.

- **For aggregators:** It was noted that additional financial incentives for load reduction in **(S2)** did not help to achieve such form of DSR for the commercial trials. Aggregators expressed positive views on the change of dispatch notification. A week in advance notice allowed aggregators and their clients to participate in other DSR activities.
- **For firms:** Participating in the trials it was noted that DSR can add value to the business as long as it does not restrict core business operations.
- **For DNOs:** DSR on higher network levels (e.g. 33kV) may be more commercially viable compared to the 11kV network level. Moreover, further DSR trials may explore

possibilities to establish relationships with customers to provide DSR direct to the DNO and not via an intermediary.

13.4 Comparing stakeholder feedback (S1) and (S2)

This section compares the insights gained from stakeholder interviews for **(S1)** and **(S2)** with particular focus on the modification of the trials. Following **(S1)** the DSR trials developed in FALCON was modified to allow for additional financial incentives for DSR via load reduction. Moreover, notification of dispatch changed from 30 minutes to a week in advance notice.

Overall, aggregators and firms that participated in the trials expressed positive views on the modifications made in this DSR trials. The financial aspect is important for both aggregators and firms to provide DSR. For aggregators, the financial reward must justify the cost of establishing relationship with clients to provide DSR. For customers, DSR can have multiple benefits including financial reward, energy management, carbon reduction and CSR credentials. However, the additional incentives to aggregators did not enable DSR from load reduction to be achieved.
The modification of dispatch was positively received because this allowed both aggregators and firms involved in the trials to engage in other DSR activities in parallel with the FALCON commercial trials.

Having presented the findings from stakeholder interviews with aggregators and firms participating in the FALCON commercial trials, including a comparison between **(S1)** and **(S2),** the following section presents the findings from an internal workshop with members of the FALCON team.

13.5 Internal workshop: Exploring developments of DSR on the DNO network

Instead of an interview, an internal workshop with members of the FALCON team[4] was organised and led by the OU team on May 13th 2015 following **(S2)**. Held at the Open University's Walton Hall Campus, the workshop explored developments in DSR, with particular reference to the role and perspective of DNOs in such initiatives. Participants at this workshop, notably the Commercial Trials Lead (CTL), stated that DSR initiatives have stimulated learning and development in DNOs. DNOs have been on a journey in which they have learned about DSR from various LCNI trials, which have shaped the nature and direction of DSR developments. CTL stated that such journeys could be divided into four stages.

[4] Commercial Trials Lead (CTL), Knowledge Lead (KL) and Project Coordinator (PC)

1. Prior to the LCNI trials it was noted that DSR was not a standard technique deployed by DNOs to operate and maintain distribution networks. The LCNI trials including project FALCON created an opportunity for DNOs to develop and test DSR. Thus, at the beginning DSR was a technique unused by DNOs in a formal sense but one worthy of investigation.
2. The second stage of the journey involved initial learning, in which DSR was developed and tested on the distribution network. Initial learning emerged from the early stages of LCNI trials. For example, Northern Powergrid and UK Power Networks developed and tested DSR as part of their LCNI projects[5]. These projects found that DSR can usefully be deployed by a DNO to manage network constraints. This initial learning inspired development of DSR in other LCNI projects, notably FALCON, to explore the suitability of DSR within a DNO.
3. Thus, the third stage of this journey involved learning about the suitability of DSR on the DNO network. This refers to how DSR can be developed and applied by a DNO so that such initiatives are commensurate with how DNOs operate as well as with the wider DSR landscape. The FALCON commercial trials have made important contributions to understanding the suitability of DSR on the DNO network. Details of this contribution are given below.
4. The fourth stage of this journey refers to the future development of DSR. It is likely that lessons learned in the LCNI trials will inspire follow-on projects in which DSR is further explored.

The journey described above reflects four stages through which DSR has developed in the LCNI trials (including project FALCON) with particular reference to the role and perspective of DNOs. In summary, this journey began with DSR being a novel concept for DNOs, initial learning identified the potential utility of DSR, which led to an investigation into the suitability of DSR on the DNO network, and finally recognising the need of further DSR trials. This journey metaphor helped participants at this workshop to identify important lessons learned from the FALCON commercial trials.

Exploring the potential of DSR on DNO networks

Initial learning was generated in early LCNI projects (e.g. Northern Powergrid's Customer Led Network Revolution) and identified among other things, the potential of DSR on the electricity distribution network. DSR can be deployed by DNOs to defer or avoid network reinforcement, which can be useful because predicting changes in load profiles is becoming increasingly uncertain. DNOs expect increased electricity demand to arise from new loads (e.g. the electrification of heating and transport) and reversed power flows from distributed renewable and intermittent power sources, such as wind and solar PV. Such load growth is uncertain and may present a potential challenge to the forecasting of future load profiles. DSR can thus be useful in network planning and congestion management activities on DNO networks.

[5] Please see comparative analysis in Part 2 of this report

The suitability of DSR on the DNO network

The FALCON commercial trials have generated important insights with respect to the suitability of DSR on DNO networks. In order for DSR initiatives to work for DNOs two aspects should be considered when investigating DSR implementation:

1. the network scale, i.e. high and low voltage networks
2. the DSR market landscape

Network scale matters when deploying DSR on the distribution network for two reasons,

1) number of participants with DSR capacity (e.g. standby generators), and

2) financial aspects of DSR to make it commercially viable. We now take a close look at each of these in turn below.

First, the FALCON trials were undertaken on the 11kV network and involved generation and load turndown from participating firms. The FALCON commercial trials showed that generation provided more DSR capacity (i.e. amount of Megawatts) compared to load turndown. The trials also showed that the local 11kV network has few firms with the generation capacity necessary for DSR. A DNO is unlikely to be able to depend on a small number of firms providing DSR since insufficient capacity may be available should one firm fail to respond. Internal workshop participants suggested that DSR capacity for the 11Kv network may rather be sourced from the domestic sector. However it was also noted that DSR involving domestic participants was not something that WPD is considering at present.

DSR involving firms with generation capacity may be better suited to a higher voltage network. For example, a 33kV network is more likely to have multiple firms with generation capacity from which DSR can be sourced as it spans many 11kV networks. The FALCON commercial trials also showed that the network scale matters from a financial perspective. The cost of reinforcing the High Voltage (HV) network is greater than compared with the cost of upgrading the Low Voltage (LV) network. Thus, deploying DSR on the 33kV network to manage network constraints and defer capital investment may therefore, be more commercially viable for a DNO.

Secondly, developments of DSR need to be considered in light of the broader DSR market landscape. National Grid is currently the dominant purchaser of DSR, notably via the STOR programme. A DNO may not be in a position to compete with the National Grid to purchase DSR on markets. In contrast, it may be more suitable for a DNO to promote opportunities to share DSR capacities with the National Grid. The Shared Service Framework group was initiated by CTL to help address this issue. This group is led by the Electricity Network Association (ENA).

In summary, network scale and developments in the broader DSR market landscape are two important insights identified in the FALCON commercial trials.

13.6 Discussion and Conclusions

This section discusses the insights gained from stakeholder engagement undertaken for the commercial trials and presents the conclusions.

Discussion

Stakeholder engagement in FALCON proceeded in an iterative fashion: it was modified as the commercial trials developed and new stakeholder joined. In this section, findings from stakeholders involved in the commercial trials are discussed with particular focus on their role in, perspective on and experience of the trials for both **(S1)** and **(S2).**

Role of priority stakeholders in the commercial trials: The role of aggregators and firms that participated in the commercial trials was consistent for **(S1)** and **(S2).** Aggregators provided DSR from client's site to the commercial trials. Firms participating in the trials were asked to provide DSR from generation (e.g. stand-by generator) or load reduction. In general terms, DSR reduces the load on the electricity network infrastructure. Two ways to reduce loads on the network have been tested in FALCON:

- Generation: firms with generation capacity that can be contracted to provide DSR. As such, these firms may use their generators during periods of peak demand on the network.
- Load Reduction: firms can reduce their load on the electricity network by turning off or down electric equipment (e.g. pumping) during periods of peak demand

While most firms provided DSR from generation and via an aggregator one firm participated directly with FALCON and was able to provide load reduction for **(S2).**

Key aspects considered in the DSR trials and differences between generation and demand reduction include:

- **Timing:** Generation is more likely to be available, whereas load reduction may be limited to nonessential loads or equipment that can be turned off without affecting business operations. Generation may be used at any time providing it is available.
- **Capacity:** Generation tends to have fixed capacity (such as 1MW power plant), while load reduction may require multiple assets (e.g. air-conditioning units in an office block) to be turned off to provide a sufficient reduction in demand for DSR. There is also capacity available in firms that can plan their operations and turn down electricity load to avoid periods of peak demand (e.g. 4-8 pm). However, engaging firms to turn down load may rather lead to efficiency measures involving permanent load reduction. As such, energy efficiency measures limit the capacity available for DSR.
- **Frequency:** Expected frequency of DSR events needs to be considered since firms may find too many events disruptive, especially if they provide DSR by load reduction. Frequency of DSR events also matters to participants with generators because DSR may lead to increased use of a generation asset.

- **Duration:** The duration of an event needs to be considered since generation may only be able to supply electricity for a fixed period. Similarly, firms may only be able to reduce load for limited periods of time.

Perspective of priority stakeholders on the commercial trials: Aggregators and firms that participated in the trials expressed a positive perspective on the DSR trials developed in FALCON. For aggregators, DSR on the distribution network could enable growth in the DSR market and a commercial opportunity. For customers, DSR can add value to the business (e.g. financial reward, energy management and CSR) as long as it does not restrict core business operations.

Experience of priority stakeholders of the commercial trials: Overall, aggregators and firms had a positive experience from participating in the trials and expressed interest in future development of DSR on the distribution network. However, firms that participated in the trials noted that DSR can initially be disruptive and intrusive. For example, reducing load or operating a generator may hamper business operations or affect comfort levels. Also DSR often requires monitoring and control equipment to be installed on firms' sites and such equipment may be incompatible with existing IT and security systems. Finally, a lack of information about DSR developments in the market may hamper participation in DSR programmes. Firms with DSR capacity may not be aware of the DSR programmes available to them or how to engage with this market.

For a DNO, several important findings have arisen from the FALCON commercial trials that may contribute to the further development of DSR initiatives on the DNO networks. More specifically, the network scale and the DSR landscape are important aspects of DSR, which should be considered when investigating the implementation of such initiatives. The network scale (see section 3.4 above) influences the suitability of DSR, considering availability of DSR capacity and cost of reinforcing the network. Importantly, the conclusion that network level and scale matters suggests that network context is an important part of the successful development of DSR.

The context may not only be considered in terms of voltage level, the nature and characteristics of load profiles on particular parts of the network may also matter. For example, the location of a network (such as urban, rural or in industrial regions) may influence how load profiles might develop. Networks in urban regions may face network constraints because of increased electricity demand due to new loads, e.g. electric vehicles and new urban developments. In contrast, networks in rural regions may face constraints because of the uptake of renewable and intermittent power generation, which may increase reverse power flows.

While DSR is a novel concept for DNOs, these firms may play an important role shaping the DSR landscape. In the current DSR landscape, aggregators have specialised in practices of aggregation, which involves developing relationships with energy partners, developing monitoring and control equipment and co-developing DSR programmes in collaboration with purchasers, such as the National Grid and more recently, DNOs. The FALCON commercial trials, and other LCNI projects, show that DSR may assist DNOs in managing network constraints. In other words, DNOs have important knowledge about the use of DSR on the network. Moreover, DNOs have knowledge about the network context: scale and regions in which the network is connected to firms with DSR capacity, such as generation.

Thus DNOs are in a good position to establish practices of aggregating DSR to operate and maintain the electricity network infrastructure. DNOs may be able to further develop relationships with energy partners, develop monitoring and control equipment to manage DSR and co-develop DSR programmes with relevant stakeholders, such as the National Grid, renewable electricity generators and firms with DSR capacity. Importantly, DSR may not only be a method deployed by a DNO to maintain the grid as DSR may also provide interesting opportunity to engage with electricity users to understand load profiles. Knowledge about load profiles and how these might develop can assist network planning and investment in network infrastructure.

13.7 Engagement and Learning Conclusions

In conclusion, stakeholder engagement in FALCON has provided multiple perspectives on the commercial trials and valuable insights on stakeholders' role in, perspective on and experience of the trials was gained.

- For aggregators developments of DSR on the distribution network can enable growth in the DSR market and commercial opportunity. Aggregators expressed interest in developments of the shared service framework to allow DSR on the distribution network to work in parallel with other DSR activities, e.g. STOR.
- For customers, developments of DSR can add multiple benefits to the business in terms of an additional revenue stream, energy and carbon management and CSR credentials. However, firms noted that they can participate in DSR as long as it do not restrict core business operations.
- For internal stakeholders, notably the control room, DSR must be deployed in a safe and reliable manner, and may require relationship with customers to allow for automated forms of DSR.

Insights gained from the commercial trials show that context matters for developing DSR on the distribution network. Contextual factors refer to the characteristics of network customers and the commercial viability of DSR that vary across scales. Moreover, developments in the DSR market are another contextual factor that influence the development of DSR on the distribution network. These contextual factors are further unpacked below.

- **Network Scale and load profiles**: DSR may be more suitable on the 33kV or 132 kV networks rather than the 11kV network. Distribution networks at these 'higher' scales cover several 11kV networks and are therefore likely to include many firms with embedded generation and/or load reduction capacity from which DSR can be sourced.

Related to this is the nature and characteristics of network customers and associated load profiles in which the networks are located.

- **Commercial viability**: DNOs can deploy DSR to manage network constraints and defer capital investment needed for reinforcement measures. Seen this way, the commercial viability of DSR is assessed in light of the costs associated with reinforcing the network. The cost of reinforcing distribution networks differs between scales. In general terms, the cost of reinforcing distribution networks increases with voltage levels: it is relatively low at 11kV and increase at higher network levels, e.g. 33kV and 132kV. Deploying DSR at the 33kV or 132 kV networks may therefore be more commercially viable for a DNO since capital investment needed for reinforcement is greater at these levels.
- **Contractual arrangement**: The contractual arrangements developed in FALCON's commercial trials were influenced by developments in the DSR market landscape. Notably, the DSR trials in FALCON were developed to work in parallel with the National Grid's DSR programmes, e.g. STOR. A number of contractual features were identified in the FALCON trials that allowed participants to take part in other DSR programmes. For example, the contract offered utilisation payment to participating firms, which means that they were paid for the capacity they provided. By contrast, other DSR programmes (e.g. STOR) often includes payment for availability as well as utilisation to ensure that the providers of DSR are available should DSR capacity be requested. Moreover, FALCON provided a week ahead notice to participants in the trials. The notice given to participants made it easier for them to undertake other DSR activities.

13.8 Appendix 1: Interview guide

Introduction

This interview guide outlines the approach to data collection from prioritised stakeholders involved in the FALCON commercial trials.

The purpose of data collection for prioritised stakeholders is to gain in-depth insights on their role within, perspective on and experience of the trials. Qualitative data will be collected via semi-structured interviews. This approach allows in-depth insights to be gained from interviewees and is based on a set of prepared themes and questions, which allow interviews to be open-ended and flexible. The interview guide will included the following:

1. a list of interviewees
2. schedule of interviews
3. a set of prepared question themes

The interviews will be recorded and transcribed providing that consent is given by the interviewees. Potential interviews for both the Commercial trials and the Engineering trials are detailed below, including a schedule to review interview progress.

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Interview Guide and Schedule for the Commercial Trial

A list of interviewees was identified both in ongoing review meetings with the Knolwedge Lead (KL) and in internal FALCON workshops. The following stakeholders were identified to engage with for the FALCON commercial trials:

- Key external stakeholders include aggregators and firms participating (or not) in the commercial trials. These external stakeholders were selected because of their potential involvement in and contribution to the FALCON commercial trials.
- Key internal stakeholders included FALCON team members, the Control Room Manager and the Future Network Manager. These internal stakeholders were selected because of their role within Western Power Distribution.

A schedule of interviews was identified by KL who stated which stakeholders can usefully be engaged during and after the trial period. The questions prepared for this interview guide were set out to explore the role and perspective of the key stakeholders regarding the commercial arrangement being trialled in FALCON. The questions were developed by the OU team in collaboration with KL and CTL. The interview themes and interviewees engaged in **(S1)** is detailed in Table 25.

Table 25: Interview themes developed in S1 of the commercial trials

Interview Themes	Aggregators participating	Aggregators unable to participate	Participating firms	Control Room
Information about the stakeholder (e.g. what they do)	X	X	X	X
What were you asked to do in the FALCON trials?	X	X	X	X
What needs to be done to enable commercial demand response to become business as usual?				X
What did you consider to be the benefits/costs of participating?	X	X	X	X
Why did you participate?	X		X	
Why were you unable to participate?		X		
Did you participation provide the benefits you expected?			X	
What is your view on the contract in comparison with similar schemes?	X			X
What is the difference to working with other demand response schemes?	X			
What if anything would you like to change for another trial?	X	X	X	X

Interview Themes	Aggregators participating	Aggregators unable to participate	Participating firms	Control Room
Do you see any opportunities to work with your clients for demand reduction rather than generation?	X	X		
Consider a future when all electricity contracts included the option allowing I&C customers to be paid for generating and/or reducing electricity. Would this open up opportunities for your organisation?			X	
What are the priority issues that need to be addressed in order to enable commercially driven demand response techniques?	X	X		X

Following **(S1)** interview themes and questions were modified to reflect how the FALCON commercial trials developed. Interview themes and questions developed for interviews in **(S2)** are presented in Table 26.

Table 26: Interview themes and questions developed in S2

Stakeholder group	Interview themes	Interview questions
Aggregators	Business activities and core skills	What do you do as a business? What DSR programmes are you involved in? How is your firm differentiated from other firms?
	Motives for participating in the trials	Why are you participating in these trials?
	Role in the trials	What is your role in the trials? Has your role changed between 1st and 2nd trial, if so how?
	Comparing generation with load reduction	Initial trial results strongly favour generation over load reduction, why do you think this is the case? Do you think it will change?
	Performance reliability	Performance reliability is important to DSR, what do you think can be done to ensure this?
	Future development in the DSR market and the role of aggregators in particular	What are the major threats and opportunities to the DSR market? How do you see the UK market developing in relation to DSR across the potential service purchasers? Do you see conflict between any of these and if so how would you expect these to be addressed? What is your view on future developments of aggregators within the DSR market?

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Stakeholder group	Interview themes	Interview questions
Firm participants	Business activity and energy consumption	What do you do as a business? What is energy used for in your business? Are you involved in any DSR programmes other than the FALCON trials? How does DSR compare with other aspects of energy management?
	Motives for participating in the trials	Why are you participating in the trials?
	Role in the trials	What is your role in the trials?
	Future development in the DSR market and the role of participating firms in particular	What are the major threats and opportunities to the DSR market? What is your view on future developments of aggregators within the DSR market?

SECTION 14

Summary / conclusion

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14.1 Performance against objectives

In many respects the trials were a great success in **(S1)**. The majority of the trials objectives were met including many significant developments for the industry and WPD alike. All key milestones were delivered on time and in accordance with the original plan for **T5** and **T6** as set out in the original LCNF bid and overall trials project plan. It must be acknowledged though, that there were several major challenges during each phase of the project from the initial design and build through to the operational phase where the majority of the empirical data was collected and allowed the range of learning objectives to be extended, resulting in the scope extension for **(S2).**

During the design build and **(S1)** operational phases the trial successfully delivered key objectives relating to commercial intervention techniques:

- Overall plan for commercial trials;
- Assessment of a DNO requirement within a BaU environment;
- Identification of a market structure and barriers to BaU operation;
- An appropriate cost justification model for DSR;
- Established a trial environment;
- Created a performance contract for DNO DSR;
- Developed back office software for performance monitoring and settlement;
- Engaged the entire UK Aggregator sector for participation;
- Recruited **T6** target capacity, meeting all diversity criteria to satisfy trial learning objectives;
- Recruited a directly contracted **T6** participant for comparison with third party service providers;
- Engaged with wider industry of Network and System Operators to address market barriers;
- Execution of multi-site, multi-event DSR operational trial;
- Research to capture of post event attitudinal data;
- Collection of granular site data for performance assessment;
- Operation of new back office software for programme administration and
- Completion of **(S1)** of **T6** trials. On time and on budget.

There were a small number of outstanding areas where the trials did not achieve the desired objectives during **(S1)** which we attempted to address in **(S2)** as well as gain further data in order to complete all the original learning objectives that were proposed at the outset of Project FALCON:

- Acquisition of up to 1MW capacity for **T5** load reduction trials;
- Operation of a functional Smart Meter solution for DSR;

- Improve DSR reliability rating for availability and utilisation and
- Network based monitoring to establish impact at 11kV and 33kV
- GAP analysis on DNO business to roll out DSR as a BaU service.

14.2 Added objectives for (S2)

The findings presented in the interim report, published June 2014 already led to several observations that progressed the DNO view of DSR to date. Some of these new factors disrupted the original plan for Project FALCON to carry out two years of identical trials in order that the research could be initially tested then validated in the subsequent winter's operation. In particular the understanding of the current market and its barriers were broached within a working group that was proposed by WPD before establishing sector wide support. Ultimately this was ratified through the ENFG, chaired by the ENA and attended by the UK DNO's and National Grid.

The Energy Networks Association (ENA) Electricity Demand Side Response Shared Services group was established to provide an electricity network operator (distribution, transmission and system) perspective of how DSR could be utilised by different parties. It set out a potential sharing framework under which the electricity network operators would be able to jointly access DSR resources. The framework focused on how network companies could maximise the DSR value chain within the price control periods for RIIO-T1 and RIIO- ED1, with particular emphasis on Distribution Network Operators (DNO) and National Electricity Transmission System Operator (NETSO). Further details regarding the findings and consultation published by the group are contained in section16.5.

The group developed a Shared Services Framework proposal that sought to address the conflicts between a DNO use case and the most commonly contracted balancing service STOR. This has a great deal of potential to enable participant to offer services to both a DNO and National Grid and we were therefore keen to incorporate a trial of some the main service requirements in **(S2)**. The main principles that we were keen to test were

- week ahead notification of dispatch
- smart meter solution for site monitoring
- capped demand based DSR targets
- enhanced payments for load reduction

Details of the WPD project change request and altered scope and objectives are listed in section 18.

The week ahead notifications were necessary to comply with the findings of the shared services group but it was hoped that it may also assist with a much needed improvement in the reliability of DSR for DNO use cases. Based upon the **(S1)** reliability statistics, it would be very difficult to offer a recommendation to use commercial intervention techniques as a long term alternative to engineering based methods. There is however a growing case to use DSR as a shorter term solution to manage potential or transient constraint issues by operational methods rather than engineering upgrades to the network. This could be particularly applicable where the investment case is not yet clear and the DNO is yet to identify capital spend as part of their well justified long term development plan.

14.3 Understanding the 'Use Case' based on results

From a DNO perspective, one of the major benefits for a service based method of managing a constraint issue through commercial techniques means that it will typically only incur costs to the business when it is being used. As a result it is far less likely to be in a situation where a large capital spend is necessary, but the extra capacity that it adds is underutilised. A good example of this is where a DNO makes an investment decision to upgrade network capacity at a substation based on annual consumption data clearly showing a steady rise in load which is assumed to continue to the point the existing infrastructure becomes overloaded. However, without the benefit of going and speaking with the main customer being fed off of the substation the network planners are not aware that the customer site in question is not just growing in load, but physical footprint and as a result they expect to move premises within the next few years. The result being that shortly after the upgrades to the network take place, the customer moves elsewhere and leaves the recent investment as stranded and under-utilised assets. Under such circumstances, if the DNO was aware of the temporary nature of the peak load requirement it may well have been the case that a DSR programme would have been quicker, more economic and less disruptive alternative. It may even be the case that the peak load never reaches critical levels requiring further action to be taken, and in those circumstances the whole initiative would cost no more than the nominal expenditure associated with initial set up of the contracts and any ancillary equipment such as metering.

It is expected that if DSR arrangements were to be used more extensively where future projections of load may cause brief or intermittent overloading on the network then it would not only be the short to mid-term solution, but also the trigger for investment reviews. By putting DSR contracts in place the DNO would require to talk with the customers connected to the potentially constrained network, this would in turn help provide intelligence that would help educate planners on the sensitivities that may affect their projected load models. Thereafter the DSR would provide a solution that would mitigate the need to reinforce the network ahead of need. If the DSR service was then utilised it could trigger an investment review to reassess the network and determine whether the case for capital investment has been made or whether any constraints are still going to be a rare incident, best managed through commercial arrangements. This would create an opportunity to re-run the SIM and establish what would be the best method. The SIM would then be used to establish whether commercial techniques remain part of an optimal solution or whether a combination of any of the five other techniques modelled within FALCON are more favourable:

- Conventional Reinforcement;

- Dynamic Asset Rating;
- Automatic Load Transfer;
- Meshed Networks
- Energy Storage.

This type of commercial arrangement is expected to work well with the planning of Distribution Networks of the future as the modelling of expected load conditions continue to become more challenging. With the changing use of electricity as highlighted in the early sections of the document, we expect to see increased volatility in the electricity demand profiles, as outlined in the table below. There are many factors that can, and will, interfere with making longer term predictions of what the future load characteristics will be on specific parts of the network

Table 27 - influencing factors on future energy demands

Influence	Impact
Electrification of transportation	↑
Electrification of heating	↑
Energy Efficiency measures	↓
ToU Tariffs	↔
Businesses moves premises	↓
Businesses growth / expansion	↑
Embedded generation	↓
Government policy / incentives	↕
Domestic Smart Meters	↓
General growth in domestic consumer electrical goods	↑

KEY	
Increase demand	↑
Decrease demand	↓
Shift demand	↔
Conflicting impacts	↕

The impact of these various factors can start to take effect in concentrated pockets within the network over relatively short periods of time, depending on incentives and uptake of certain technologies. This has already been the case to date with reverse power flows and thermal constraints resulting from deployment of solar and wind generation by large developers or promotions focussed on uptake within specific communities. However it is feasible, particularly in domestic environments that a sudden uptake of heat pumps or electric vehicles could occur over the coming decade. This would not necessarily result in a self-balanced system, but could in fact create higher peaks and deeper troughs in the daily demand profile if allowed to develop without controls or governance structures. For this and other reasons, it is vital that DNOs start to develop capabilities to that will enable them to start to forecast the likely profiles of demand and generation and be able to take some direct actions to assist in the efficient management. There are already some blunt instruments such as DUoS charging (see section 22.5.5) that in theory allow each DNO to set an appropriate price signal to encourage customer behaviours. This unfortunately is still aligned with a centralised system where the almost all connections are to consumers and the costs are calculated on the assumption of centralised generation supplies. This has become rapidly outdated in recent years as a result of the growth in distributed generation much of which is subject to weather and time of year.

DUoS and GDUoS rates are set annually and broke down by DNO franchise area, without the ability to separate into smaller regions or individual seasons. We can therefore increasingly find that often the payment or charge being applied is for much of the time in conflict with the demands being placed upon the network. For example, solar generation will for the most part receive additional payment through GDUoS during summer afternoons and early evenings, when in fact it is likely to be creating a problem. There are many cases where the DNO is likely to have to make very large capital investments to reinforce in order to be able to move the energy many miles to feed distant consumers. It may be that a restructuring of DUoS / GDUoS should be proposed to allow increased granularity of locational effect as well as being able to reflect time of day and year would assist the management of the network. However this is likely to take time and be subject to lengthy consultation processes and red tape. Therefore the ability to develop systems in line with the immediate needs of DNOs to influence or control behaviour is becoming a very attractive proposition.

14.4 Technical outcomes

While the trials were largely focussed on the impact of commercial techniques to manage network constraints, there were inevitably some technical aspects to the trials

- Metering
- Dispatch
- Forecasting
- Performance Monitoring
- Financial settlement / Billing
- Asset reliability

In several instances the changes from **(S1)** to **(S2)** meant we obtained a wider set of results than we had initially set out to achieve. One area where this was particularly obvious was within the metering arrangements.

14.4.1 Metering

The **(S1)** metering largely adopted existing metering arrangements from customer own equipment, which included aggregator provided metering and output metering from the generator control systems. This was viable as we were only requiring to measure a delta shift in output or consumption at the point of impact on the customer site. This resulted in a range of different file formats and sometimes variable quality of data being provided. In many instances it was necessary for the site or their aggregator to manually extract or manipulate data from the default output file into another that would be compatible with the back office systems we developed for performance assessment and financial settlement. In a worst case scenario this could be open to abuse, allowing a participant to adjust the file and therefore the readings and it would be very difficult to detect. This is merely an observation and under no circumstances is there any suggestion that there may have been incidents during **(S1)**.

The move in **(S2)** to a consumption cap necessitated a change of metering solution in order that the site could be measured at the point of connection. For this reason we adopted an alternative design where a smart meter capable of 1 min reading intervals was installed in series with the sites existing half hourly settlement meter. This had been pre-tested in laboratory conditions by WPD Smart Metering team and the result was a smooth roll-out without any issues to report. The data collection was based upon existing procedures for conventional remote meter reading and the data supplied the following day to a secure environment within WPD's IT. Due to the standardised meter type and pre-configuration before installation, there were no data integrity issues where the software encountered corrupt or incomplete files that had presented problems during **(S1)**.

It is expected that for DNO purposes a demand cap is likely to be the more appropriate method of targeting and monitoring participants as the use case relates more appropriately to geographical constraints. This is very different from National System balancing DSR services that are non-geographic and as a result can be measured at the point of generation. When it comes to 'non-geographic service requirements, the programme operator is typically n ot concerned about the point of entry or exit for electricity in and out of the system, merely that both aspects are kept in balance with each other. It is therefore recommended that DNOs do not adopt the metering standards from non-geographic services but instead specify metering that is compatible with measuring an overall capping of site demand.

14.4.2 Service Dispatch

The FALCON trial did not attempt to create a direct interface to customer sites via a machine to machine or automated dispatch methods. It was not deemed necessary to duplicate capability that already exists within the DSR industry and other asset automation trials. The ability to communicate directly with assets on customer sites and even monitor their performance in real time would have been an unnecessary expense within the scope of the learning we hoped to achieve.

It has been proven that this can be achieved through a variety of different devices and over a wide range of communication types. It was also unnecessary to invest in the integration of the dispatch capability within existing control room systems as the trials would not be seeking to manage any live constraints within the trial zone. Even within the remit to provide DSR services within BaU it is entirely feasible that limited programmes could be facilitated without the necessity for complex M2M. This is reflected in the the trials results which achieved acceptable levels of reliability in **(S2)** without the benefit of automation. This is largely down to the unprecedented notice period of 5-12 days' notice of events. The combination of generous notice periods coupled with the expectation of low event volumes means that more complex arrangement are potentially a bad investment. It would however be recommended that annual briefings take place with participants. This could be direct or via an aggregator with a view to ensuring that sites remain familiar with their responsibilities and DSR processes. This could potentially include an annual test event prior to any particular season in which there is an increased expectation or use.

14.4.3 Forecasting

With 7 -12 day event notification periods within the **(S2)** period of the operational trials there was an added requirement to test forecasting of event requirements in parallel. This would allow the principles of the 'Shared Services Framework' to be pursued if a successful outcome were to be achieved.

Currently DNOs do not do this type of operational forecasting other than for the potential of serious weather events that may damage the infrastructure and require additional engineering resources to be available 'on-call'. Typically the core of DNO forecasting is demand profile trends over a number of years in order to assess the areas of network that are likely to require further investment.

Using primarily weather data, National Grid's National Demand forecasts and some historical consumption data the trials lead attempted to identify the period of peak load on the network. These required to be condensed down to individual days and periods of up to two hours during any given day. The general results were very positive and a clear improvement in this could be achieved from the data collected during the trial being used to support future methods. There was parallel activity that took place within the trial to help determine the relationship between local demand and national peaks. It was noted that in doing so the FALCON DSR event dispatches managed to accord with two of the three National demand peaks on which the annual TNUoS charges are calculated, despite setting the dispatch notifications at least a week ahead. The level of correlation between local and national conditions was however not as closely matched as had been expected and for the majority of the DSR events the local peak occurred earlier than nationally. Further research work will

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be required in order to test this further to gain a more detailed understanding of the factors that help influence the results.

- Commercial vs Domestic demand
- Geography
- Triad, DUoS and time of use tariff impacts

14.4.4 Performance monitoring

The performance monitoring of the sites that was developed for the trials was adequate for that purpose. It would be expected that if this was to be implemented in a BaU environments then there would be a single directing factor that would determine whether a similar high level design would still be suited. If there were multiple sites participating in the load reduction and thereby sharing the risk of critical failure on the network due to DSR reliability then it is feasible that performance monitoring could continue to be carried out post-event. In this scenario it is recognised the primary purpose is for ongoing statistical analysis of the constraint requirements and associated financial settlement. If however the risk profile was to be particularly reliant on a small number of sites or even that of a single DSR respondent it is likely that real-time monitoring would be necessary in order to ensure that there was sufficient visibility and notice within the control room to take alternative action ahead of the failure of a DSR participant leading to critical network issues affecting other customers.

14.4.5 Financial settlement / Billing

The financial billing and settlement aspect of the trials will be regarded as a great success despite the difficulties during **(S1)** resulting from the integrity of the data for input and in turn causing the settlements process fail its deadlines. However this was fully addressed within **(S2)** and the extensive revisions that were made to the interface and the manner in which the new standardised data would be processed.

Most importantly the trials set out an objective to design an appropriate payment model that could be authored in terms of algorithms that would underpin an accurate, automated system for financial settlement but also be simple enough to convey within a contract what the service delivery parameters would be for participants. This was in fact achieved twice as the change of scope for **(S2)** necessitated a full re-authoring of the underlying algorithms, which in turn received acknowledgement and praise during the post-trial stakeholder analysis.

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14.5 DNO skills and resources – Gap Analysis.

The technical challenges within the trials for the most part required to be addressed in order to enable them to function and be measured. This requirements was not as acute for much of the skills and resourcing due the operation of the Commercial Trials being outsourced to SGC who already have the majority of the knowledge and experience, but also the scale meant that it could all be done in isolation from WPD's core operations. If however DSR were to be considered for use within a BaU environment there would need to be a whole new set of resources with the appropriate skills, processes and new tools in order to work efficiently. In this section we will highlight some of the key areas in which a DNO would require to develop its existing business and invest in its development personnel and systems. These have been separated into four topics

- Network requirements
- Engagement / Account management
- Operational intelligence
- Commercial Management

14.5.1 Network Requirements

The application of DSR is likely to be very different to more technical methods as these will most likely be capital funded works. It is important that a new set of assessment criteria are applied when determining where DSR is suitable for deployment. This is to a large extent the function of the SIM as to identify when it may be feasible but unlike other techniques it can be assumed to be available as it's not a unilateral service and require the identification and recruitment of suitable participants.

A DNO may in fact incur costs to try and identify participants and unsuccessful in recruiting adequate capacity. Under such circumstances it could be considered that DSR reliance on parties unknown at the stage of initial recommendations as a barrier to its implementation. It would therefore be worthwhile developing methods of contact and engagement with customers to educate and receive expressions of interest to start developing additional data for future use. Alternatively it may be the case that DSR arrangements are put into place to manage a forecast constraint issue, but rarely or never dispatched as the increased load peak never transpires. Under this scenario the savings over any capital funded technical solution will be extensive as well as avoiding stranded or underutilised assets.

An appropriate set of use cases and policies require to be developed in order to identify when DSR offers best value to manage short term or transient issues. It is also likely under such use cases, an annual review of the DSR arrangements will monitor the ongoing cost, requirements and if necessary trigger a review of technical alternatives.

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14.5.2 Engagement / Account Management

Probably the area of greatest change necessary for the traditional DNO business and operations will relate to the engagement with stakeholders and participants. The traditional DNO business does have contact centres to manage inbound enquiries largely relating to faults and interruptions in supply. As DNOs operate licensed franchise areas where they are monopoly providers they have not had a necessity to develop a comprehensive team of public facing representatives other than for major account management customers such as property developers. By introducing services that require to be sold and relationships developed in order to manage the ongoing performance, contracting and customer communications. Where a new set of resources and a cost centre is created within the business it will then require management structures, human resources and accounting functions to support its activities. Many of these additional costs will add little cost to the overall operation of the business as it can be absorbed within the existing resources. There will be direct cost increases resulting from the new roles of 'commercial representatives' that will be able to contact, communicate and negotiate with potential DSR participants. These costs will then require to be shared across the range of successful DSR schemes and still demonstrate good value to customers.

14.5.3 Operational Intelligence

It is not currently the case that a DNO will do operational forecasting of the power flows and varying demands within the network unless it is to manage planned outages or ahead of adverse weather conditions that have potential of causing disruption. As the networks become more volatile, with higher peaks, reverse power flows and smart solutions such as DSR to manage them, operational intelligence will become increasingly vital as it becomes increasingly expensive to build infinite capacity, passive networks. Changing conditions will demand an active energy management function that will assess conditions and affect network operations as would traditionally be the case with national system operator. This may in time develop to a point where the GB system is operated in a distributed structure where DSOs will inherit the responsibility to balance and operate local markets. The initial steps towards this are likely to be focussed on the economic operation of constrained networks through active management, to extract the maximum value out of the networks assets.

14.5.4 Commercial Management

Over and above the requirement to engage with customers, operate the services and provide the business processes support, it should also be acknowledged that there will be further strategic development of DSR and other associated smart services at a market level. It would be advisable for DNOs to ensure that an understanding and influence of factors that may impact the economics or availability of services through appointment of role that is responsible for the ongoing development of the DSR market in keeping with the DNO use cases and innovate to ensure that best value is maintained for customers.

SECTION 15

Output to SIM

The full cost of operation intended was intended to be determined during the **(S2)** phase of the trials with a view to establish the true life cost of establishing a full BaU service along with all its associated components in addition to the payments to participants. This requires to include any costs for establishing a new department with sales and account management resources as well as those for systems development and is dependent on the completion of the gap analysis.

This was to be more difficult than originally expected due to the development of the DSR use case and the identification of key market barriers that would prevent such a service being implemented. In addition it would necessitate a comparison mechanism that would require the SIM to be able to measure predictable capital investment in assets versus operational expenditure that by its very nature would be far less predictable. This section will therefore outline the approach taken by the FALCON team to establish a worthwhile use case and the criteria by which it could be measured against the other options available to network planners.

15.1 Demand Side Response (DSR)

A decision to model Load Reduction (LR) and Distributed Generation (DG) within the SIM in the same way, while simplifying some aspects of the implementation required specific controlling parameters to be required to manage both cases. This section is therefore relevant to both commercial techniques.

The essential concept is the identification of an avoidance event and the shifting of load away from the peak usually to an acceptable pre or post event interval or to supplement the site with its own generation capability. The trials had been intended to establish, and where possible quantify, the behaviour that takes place in a DSR event, however key findings from FALCON are that the sample size in the trials that were actually carried out was not sufficiently large to quantify the load turndown and/or the pre/post event adjustment increases to be able to inform the SIM implementation.

There remain considerable unknowns around LR and DG. DG is expensive and if used regularly might become more expensive than traditional reinforcement. Reliability of DG is also an issue, as demonstrated during **(S1)** FALCON trials, so that **(S2)** trials were designed to move from on-demand to pre-planned use of DSR (seeking a reliability improvement) and in such cases the SIM might be able to help with planning. At the present time DSR does not have CAPEX, only OPEX cost elements.

The SIM models N-1 operating modes in addition to the intact operating modes of the network. It is very likely that most of the detected issues will occur in N-1 modes, i.e., the probability to actually see them in real operating conditions is very low. For example, the SIM might detect a total of 50 hours of overloads on a particular asset in a year, all in different N-1 modes. Addressing the issue using battery storage or traditional reinforcement would incur significant costs. Using the DG technique, however, would very likely have a low operating cost, potentially zero if not used (assuming that contracts are place without availability fees or retainer payments), as the probability of having the aforementioned N-1 modes is very low. Consequently, the cost modelling inside the SIM should employ some sort of discounting technique for costs pertaining to transient (N-1) issues, if addressing them does not incur CAPEX.

We will also seek to determine whether the SIM can distinguish between transient failures and those that occur in normal operating mode of the network. The type of failure should be reported for every application of an intervention technique to facilitate economic analysis of DSR.

A useful addition to the SIM would be a module that is able to estimate the amount of controllable DSR capacity present in the network based on what is connected to a given substation.

Regarding DSR usage in the SIM - SIM "What-if" analysis could be used to point to where on the network DSR could be deployed, feeding the WPD business case and allowing a liaison team to take suggested locations (from SIM output) and approach any existing local generators (or potential generators) with a DSR operating proposition. On this basis DSR could therefore be a good investment for WPD (or other DNOs) when used in tandem with SIM as a planning tool and it tackles two sorts of failures: Transient and cyclic. However on the other hand the (potential) generators may see a low expectation of use and therefore poor potential for ROI on generation equipment. It is worth noting that incentives could be provided in forms outside of the trial such as alternative, low cost connection arrangements for generation that provides upfront incentives for sensibly located capacity.

In terms of trials results informing SIM Technique "parameters" for Commercial Techniques , the 2013/14 trials series used an inappropriate data capture device which did not permit the sort of analysis of local meter to substation mapping that would be needed to calibrate the SIM technique. New Squirrel devices were therefore used for the 2014/15 series trials.

Other input from trials back to SIM mainly informed how best to use it, and still evolving models for costing the commercial aspects that remain limited by conflict with other DSR services being purchased by National Grid. Costs currently looking like a "pay per use" model with no up front (DNO) investment cost but there will be a necessity to establish the total cost of recruitment and setup fees etc.

An important recommendation already made in the Commercial Trials Interim report published July 2014, a further additional dataset which would very usefully support the SIM is the knowledge of where on the network DG / LR is available. The most sensible place to locate such generation capability information will require a new register that locates known connections as well as proposed and off-grid assets. The recommendations are agnostic as to where this data would be stored but it would necessary to carry out an initial investigation and update to processes to record all future enquiries for connection. With access to this added information the SIM could look up where DG is available, though DG capability could potentially also be positioned based on some form of 'what if' logic assessing the areas where DG may be found or desired based upon the assessment of

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customer size, industry and historic demand requirements. This may also prove useful when considering prospects to be targeted for load reduction technique. If the information is not available concerning what is there already then SIM would proceed to propose placement – this represents effectively a different mode of usage of the technique.

The case for DG in the SIM is clear and there are possibilities of the SIM supporting the DSR business case in assessing how much DSR might be used and when and where to locate it. It is also of potential use to the SIM (and more widely the business) to know where DG is actually already available. This could be made known to the ANM in the future (though this does require a change to be made to the system).

When LR is requested for period, depending on the type that is being offered to be reduced, the project analysis determined that there may be:

An increase in the customer demand (from its normal demand) in the time periods immediately before the requested period (if it is a pre-scheduled request); and

An increase in the customer demand (from the normal demand) in the time periods immediately after the requested period in order to recover any postpones processes.

This is natural and reflects preparatory and recovery activities such as pre and post cooling (for refrigeration for example). The pre-increase, reduction and post increase amounts are based upon a percentage of the demands in the respective periods. In this way it is possible to model different types of demand response, for example:

Setting the Pre and Post increase percentage to zero would model the response as a reduction in the demand during the period with no increase before or after the response period;

Setting the Post increase percentage to zero would model the response as a reduction in the demand during the period with an increase before but no increase after the response period; Setting the pre-increase percentage to zero would model the response as a reduction in the demand during the period with no increase before but an increase after the response period.

Note: An alternative method would be to set the pre-Increase period to zero instead of setting the pre-increase kW to zero and similarly for the post increase period and kW.

In practice, the FALCON field trials were unable to gather the necessary quantitative information required to correctly gauge the pre/post event levels. This has been covered in several other areas of the report, and there are various factors relating to why insufficient load reduction participants could be identified. One of those suggested from **(S1)** was that due to the typically smaller capacity of DSR that can be offered by reduction sites versus that generation makes the financial incentive insufficient. The **(S2)** trial therefore tested this sensitivity by doubling the payment for load reduction sites and confirmed the inclusion of SIM capability to vary the incentive levels between techniques.

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15.1.1 Load Reduction (LR)

One of the key findings was therefore that identification, recruitment and operation of LR is at this time unlikely. Despite two years of opportunity being presented to the all UK demand response aggregators to recruit for FALCON they were unable to bring any to the trials despite the broad geography of the trial zone. It is therefore statistically unlikely that suitable sites can be found exactly where they would be needed in order to employ DSR as a standard technique to manage 11kV constraints. Thus, the trials effectively stresses that the current arrangements are not sufficiently attractive to customers, but in spite of this it is still valuable to include Load Reduction in the SIM to assess the outcomes which arise. However the approach taken is to only include half hourly metered customers as possibly being interested and to set take-up values as quite low. Based on this it is possible to do some sensitivity analysis on what would happen if prices and take-up were higher or lower than the initial assumptions. This allows the project to at least include some analysis on the impact of relative levels of LR and what costs would be needed to compete with other techniques.

To manage Load splitting.

The technique originally assumed that in each half hourly load value there would be a split by end use. This became unwieldy so it was suggested to add a split by category and time of day that could be applied to the values from the energy model within IPSA. To support this it was necessary to categorise all the substations in the ANM and provide a mechanism by which these could be passed to IPSA.

Parameter Validation.

Data from trials is only available to provide input validation for distributed generation. It is possible to look in greater depth at the generator functions / type and fuel source if this is of value or concern. The only FALCON commercial trials data available for load reduction is the industrial load from a single water processing site. This is an insufficient base from which to draw any meaningful conclusions.

For demand reduction by end use the implementation used a parameterised DSR function to specify what percentage of each load type might be reduced under DSR and required this value to also incorporate an estimate of reliability. So, for example, if the substation has 100kW of refrigeration load and we set the demand reduction factor for refrigeration at 30% then it assumes that it is possible to reduce refrigeration load by 30kW.

This demand reduction factor percentage value has to reflect:

1. What proportion of load relates to I&C customers (if we are considering I&C DSR only);
2. What proportion of load customers can technically shift;
3. What proportion of customers would contract to shift load, and;
4. What proportion of customers would shift load when required – i.e. reliability.

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Values for case 1 could be derived, the proportion of load that is I&C customers, for each substation. This is for each substation and means further detail to pass from ANM to IPSA. Based on results rather than assumptions we would have to conclude the volume of available load reduction is zero from substations.

However values for 2 and 3 were considered to be difficult to obtain – an area that perhaps requires further investigation. Adequate customer data is not available to identify whether it was a lack of technical capability or insufficient interest that prevented them providing service.

To be able to proceed, for technical shift capability 2, the assumption of 50% for each type of load was made. For 3, the proportion that would sign up to a contract, given the lack of willingness to sign up for DSR, we assumed application of a very low value here, but if this had been set to zero then we would have been unable to model DG either. The project did not have details of where customers have their own standby generation so it was not possible to increase the factor for those customers only.

It was possible to obtain a view of the split of load between half hourly and non-half hourly metered I&C customers. The question then is: If we were to put a likelihood value on it, what would be reasonable assumption for participation rates if the price is "reasonably attractive". Values of 5% of customers in profile class 5-8 and 10% of half hourly metered customers seemed to provide a reasonable starting assumption.

An estimate of reliability for point 4 derived from FALCON trials and others indicated 75% as a reasonable starting assumption. It is critical that separation of the two commercial technique methods is maintained as it would be misleading to present generator results for load reductions.

Other parameters

The code was initially set for half hour of pre-demand reduction activity, followed by half an hour of demand reduction and another half an hour of post demand reduction recovery. It seemed to be a fair position to take that we would be more likely to contract for more than half an hour of demand response – perhaps two to two and a half hours. The forecasting method has confirmed that really we need to contract for a minimum of 90 minutes to around 180 minutes although the majority of events will be manageable with two hour event window. It should be noted that generation doesn't require any recovery as the site should not have a rebound effect resulting in a rise above the expected returning load.

For completeness, it was assumed that there were no more than 15 applications of DSR per site per year with no more than 30 hours a year max duration. Again this is a point available for validation from the trials but is a useful variable that will enable several commercial assessment scenarios to be tested. Its is expected to indicate that if DSR is recommended for use it will be where it is not being used for 50 or even 20 hours per annum for 11kV. If it is very occasional under planned n-1 conditions then it is going to probably give a huge financial benefit but once regular events are likely then it would be expected that capital investment would be the preference of the business. Data would tend to suggest that we should use a metric of 20 events and 50 hours to be safe. This is the upper end of what

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would prove to be economically viable in any single year. However as this is 'pay as you go' it would not be expected for this to be required unless a worst case scenario year occurred where there was a prolonged cold spell or n-1 condition driving abnormal circumstances. If this was forecast to be a common annual requirement then it would be worthwhile revisiting capital funded options.

15.1.2 Distributed Generation (DG)

Following due consideration a separate technique specification for DG was not provided by the project and therefore the same underlying algorithmic model for the techniques was used for both LR and DG. For DG however a change was needed to reflect the fact that customers using DG would not have much by way of pre-demand reduction load increase (i.e. no freezer pre-cooling for example) or post-demand reduction load increase (e.g. no recovery from heating systems working harder). Having one single approach to the two techniques does however effectively mean that it is necessary to have a set of controlling parameters that work for both cases. This therefore adds certain complications as we might assume, say, that all refrigeration load could be reduced if we are switching to DG but only some of it if LR is assumed.

Because of this approach, the two techniques are discussed in detail together – so the reader is referred to the section above on LR.

15.2 DSM/DG Cost Elements

The two commercial techniques will be treated together as their management is identical.

These techniques must also be viewed for what they are and the SIM requires to operate them basically in accordance with how they would be deployed in the real world. It is worth describing this here for completeness.

The ideal time to deploy DSR (LR or DG) is to offset a capital cost (CAPEX expenditure item) through a period of uncertainty, allowing a situation to develop to a point where it is understood how the engineering response should actually be constructed including perhaps the issue having been deferred indefinitely. This might therefore allow, say, a DSR strategy to be deployed to the real world network during an interval while a new development (that might add load to the network) is decided upon. If the full development should not proceed, then DSR can bridge the gap while the full extent of the engineering response required becomes clear. The SIM might therefore model similar scenarios, providing a more realistic overall view.

It can be seen therefore that DSR is operated more as a form of insurance (and/or fallback capability) rather than being a full, complete, final solution to a network capacity issue and the SIM result set should reflect this reality.

15.2.1 Business Operating Model

There is some significant uncertainty at the present time as to how the management of these techniques would be carried out by WPD going forwards and is likely to be the subject of further trials. There are different operating model options available to the business and these options will impact significantly on actual cost values (with the trade-off being made against control of the process). The main options, which are still being assessed, are:

- To call on the services of Aggregators external to the organisation to manage this function. Aggregators work by taking a share of revenue so there is no immediate cost to the DNO of operating in this mode.
- To operate a dedicated team within WPD responsible for the management of DSR and DG. The overall function would include the separate aspects of:
  - recruitment of participating organisations and management of the contractual aspects of arrangements and,
  - Dispatch/cease operations management.

If this approach were to be adopted, the teams might be run as cost centres which could be self-sustaining, or even profitable provision of service to other external DSR programmes such as those operated by National Grid.

Certainly the issues are extensive as there is also the background question of the nature of WPD's active participation in service provision, moving this more into the realms of a DSO (section 17). This whole area has evolved significantly over the duration of the FALCON trials, and while a view on this is being derived so as to move this forwards at the present time, no decision is expected in the immediate future as to whether an in-house team or aggregator model would be used, and how WPD should approach the broader questions that are raised.

A further complication also arises in deciding how to assign the cost elements to the SIM preferred cost categorisations (CAPEX/OPEX). DSR has no associated assets, and all costs can therefore be effectively assigned as operational costs. However there may be an accounting preference to apportion certain costs to CAPEX. Again this depends on the operating model chosen. So, should an in-house team be the chosen approach, the initial set-up costs could be assigned to CAPEX with an operational component, or the whole of the overall management process could be set up as a single up-front CAPEX cost.

The model chosen is effectively an accounting preference.

In terms of actual costs, £300/MWh is the currently established PER USAGE figure used within FALCON and therefore this was assumed for the SIM cost model. This is from information provided from within the FALCON team, and is itself based on a number of operating assumptions which may need further validation and which may therefore result in further revision to the quoted figure.

CAPEX and OPEX costs cannot be established presently because of the uncertainty described above. Until this is decided upon, the range of possible cost values are potentially large. However it is possible to make the simplifying assumption for now that the Aggregator model will be used, and that in-house costs are therefore zero on CAPEX and maintenance OPEX, adopting the figure quoted above for the per usage cost (on a per MWh basis).

SECTION 16

DSR Shared services

WPD's Tier 1 LCNF project Seasonal Generation Deployment from back in 2001 was one of the industry's first attempts to test DSR for Distribution Network support. It was voluntarily ended prematurely due to vital learning outcomes relating to market barriers. These discoveries served as a basis to some of the objectives set out for the subsequent commercial trials incorporated within Project FALCON. The market barriers presented a substantial negative influence on widespread use of DSR by DNOs through the necessity to contract exclusively with a participant site. This conflict was primarily in association with National Grid's balancing service STOR.

In response to the identified issues the Energy Networks Association (ENA) Electricity Demand Side Response Shared Services group was established to provide an electricity network operator (distribution, transmission and system) perspective of how DSR could be utilised by different parties. It sets out a potential sharing framework under which the electricity network operators are able to jointly access DSR resources.

16.1 ENA Electricity Demand Side Response Shared Service Group Terms of Reference

The following is a copy of the Terms of Reference for the group as published in the Demand Side Response Shared Services Framework Concept Paper for industry consultation in April 2014.

Introduction

Demand Side Response (DSR) is being activity discussed in many areas within the electricity market as a tool which may potentially be utilised by multiple parties to assist in:

- balancing energy portfolios;
- balancing supply and demand in electricity networks;
- deferring and/or avoiding network investment and
- Addressing network constraint issues.

The Demand Side Response Shared Service Group will provide an electricity network operator (distribution, transmission and system operator) perspective of how DSR may be utilised by different parties and how DSR services could be developed in an inclusive manner that may potential allow multi-party use of a single DSR asset.

Purpose and Aim

The purpose of the group is to gain an understanding of the potential synergies and conflicts regarding multi-party use of DSR resources. In particular the group will focus on gaining:

- An understanding about how DSR is currently utilised by the network owners and operators;

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- An understanding about how DSR could be utilised (and the benefits to the different parties involved); and
- An understanding of how DSR resources can be shared.

Outputs

The group will produce a report which will describe, from a networks perspective, how a DSR shared service model could potentially be developed. The report will provide:

- an overview of how DSR is currently being utilised by network operators and how the utilisation of DSR may potential develop in the future within the wide electricity market;
- a summary of a proposed shared service model (who uses it, when it is used and how is it used) along with the associated benefits, considerations and challenges; and
- a way forward identifying next steps in the initiative (including potential issues and challenges which would require resolution).

The report will be externally published and will provide the platform from which to further the discussions on this topic with other relevant parties through the appropriate industry channel.

Reporting

The group will report to the ENA Electricity Networks and Future Group (ENFG) and the Chair of the group will update the ENFG members at each meeting.

The group will provide regular updates to DECC's and Ofgem's Smart Grid Forum Workstream 6, given the close interaction in topic area.

Membership and Logistics

All ENA Electricity members, who have an interest in demand side response, will be invited to attend and actively participate in the group:

- Each ENA Electricity Member Company may appoint one or more representative(s) to sit on the group;
- The group will appoint an ENA Member Company representative to chair the group (nominally NGET representative);
- The secretariat for the Group will be provided by the ENA;
- Additionally the group may offer membership to external stakeholders (as and when appropriate).

The group will meet on a regular basis and normally meetings will be held at the ENA Offices in London.

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Following each meeting, the ENA secretariat will ensure that a record of action notes is completed and where necessary documents are circulated and actions followed up.

Compliance

The Group will at all times comply with the requirements of the 1998 Competition Act and will not deal with any matter which will or is likely to prevent, restrict or distort competition or constitute an abuse of a dominant position as construed within the Act.

16.2 Use Cases

The process applied within the group which met regularly for over a year sought to determine the exiting processes and how the key actors within the current market intend to use DSR for their differing needs. From this it was established that the use cases were different and that the contractual arrangement presented the greatest aspect of conflict.

The operational requirements have three key differentiators;

Operational Requirement	DNO	TSO
Geographic sensitivity	Yes	No
Period of notice to dispatch	Long	Short
Availability of alternative capacity	Unlikely	Yes

If the contractual challenges were not met and the status quo maintained it will establish a market price based on exclusive access to sites. The competitive conditions would create unjustifiable payments to participants in the majority of instances for a DNO to compete with National Grid. As both are ultimately funded by energy consumers it would be inappropriate to allow this condition to continue.

The variations between the operational requirements indicated that it may be possible to establish a single framework that allowed multiple access to a DSR asset. By doing so, it will be possible to;

- Address functional requirements of TSO and DNO in a cost effective manner;
- Demonstrate increased value to consumers;
- Improve conditions for DNO adoption of DSR;
- Increase the range of opportunities for DSR participants and
- Establish the principal of asset sharing.

16.3 Sharing Principles

The DSR shared service framework incorporated a number of key principles which provided a baseline against which the proposed framework concept was developed:

Timeline

The framework focuses on how network companies can maximise the DSR value chain within the price control periods for RIIO-T1 and RIIO-ED1, with particular emphasis on DNO and NETSO. (National Electricity Transmission System Operator)

It is acknowledged that the TOs (Transmission Operators) are considering how they could potentially utilise DSR for their network requirements and may in the future take an active engagement and interest in DSR services. However given the associated time scales, the main focus of the framework is the interaction between the DNO and NETSO requirements and the DSR service provider in the immediate future.

Volumes

It is anticipated that in the short to medium term, the volumes and frequency of DSR used by the DNOs will be small in comparison to that procured by the SO. If the volumes and frequency increased, the framework will be reviewed to ensure that it remain fits for purpose.

Innovation

The framework should facilitate innovation in how each party develops their DSR services given the individual specific requirements of the network companies (based on volumes and location).

Multi Party Access and Interaction

The framework considers the concept of more than one party (DNO and SO perspective) accessing a resource which provides a DSR service.

Consumer Choice

DSR service providers should have the commercial freedom and final choice to participate in the provision of DSR services to as many network companies as they choose

16.4 Proposal Summary

The group worked through the use cases and identified where there were areas of existing conflict and where changes to the current arrangements could enable increased synergy. A general concept for sharing was developed and two practical methods in which it could be implemented. The general concept was developed around the key differences in the operational requirements:

Geographic sensitivity

The primary function of the National Grid STOR service is to support system balancing on a National basis and for the majority of actions there is little differentiation on impact between participants regardless of location. For a DNO to benefit from DSR for constraint management it has to be located downstream of that point in the network, resulting in a critical requirement to be located within a restricted location.

Period of notice to dispatch

National Grid require to balance the system in real time and DSR events can be dispatched with as little notice as six minutes.

For pre-fault constraint management of the type that is being trialled in FALCON, a Control Room are likely to agree the need for DSR in advance as part of ongoing operational planning. While this is not currently a major activity within the operation of Distribution Networks, it is likely to increase as smart grids continue to develop. It was therefore assumed that a DNO could issue event notifications up to a week ahead.

Availability of alternative capacity

National Grid operates a tender process on an economic basis and will procure a variety of different sources of STOR including DSR and different types of power stations. The range of operational costs and diversity of asset type result in a large pool of capacity which will normally be dispatched when required in ascending price order. In the event that National Grid has agreed to relinquish the use of an asset under the sharing arrangements there should always be adequate remaining capacity, albeit a small marginal increase to the cost of a STOR event is expected.

The two models proposed are at this stage still restricted at this stage to general principals as depending on which is preferred there are still many details to resolve before a sharing model can be implemented. Some of these technicalities include the considerable likelihood that the asset may constitute a portion of a larger aggregated group and interaction with triads. Some of these specifics will be incorporated into the 2014/15 FALCON trials.

While the principal is very similar with the two proposed models, they establish different approaches as to the sharing of various components that make up the overall framework;

- Contract;
- System dispatch;
- Metering;
- Procurement and
- Monetary flows.

A consultation was published in April 2014, presenting the work of the group and the two approaches that address pre and post fault conditions for DNO constraint management:

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- Alignment Path (pre-fault only)
- Asset Sharing (pre and post-fault)

16.4.1 Alignment Path

When the benefit from the DSR service is exclusive to one party, the ‘Alignment Path’ is most appropriate. The benefit of the ‘Alignment Path’ is in how procurement and utilisation of DSR services can be optimised to maximise the value of the DSR resources whilst acknowledging that parties (e.g. DNO and SO) cannot simultaneously dispatch the resource to meet the requirements of the respective parties.

A circumstance when the alignment path may be utilised is outlined below:

The SO energy reserve products, DNO pre-event service:

The DNO require the DSR resource to confirm their availability for pre fault conditions, DSR resource not available for selection by the SO.

For example, in circumstances where a NO may wish to peak shave in the winter to avoid/defer network investment, they may wish to use DSR as a cost effective alternative. Here the NO has pre knowledge of the peak and can plan the necessary actions and 'reserve' the DSR for the pre-event (i.e. the peak). In this situation, the DSR asset is locked out to the SO because of the known firm need of the NO. However during the summer, when the NO may not need the DSR service, it could be released for used by the SO and other parties.

The key benefit of this approach is the potential for increased procurement alignment which should enable the true economic costs of procuring DSR services to be reflected on the procuring party and facilitate the efficient procurement of the resources.

From an end consumer perspective it will ensure the network companies to consider and utilise the most cost effective solution to their network/system issue.

The framework also proposes:

- separate contractual arrangements between the DSR service provider and the relevant network companies;
- separate procurement strategies for the procurement of DSR services by the network companies;
- separate dispatch mechanisms for utilisation of the DSR services by the network companies;
- clearly defined data exchange arrangements between the network companies and the DSR service provider;
- clearly defined and complementary contractual arrangements (inclusion of any data sharing requirements) between the NO, SO and the DSR service provider; and
- the network companies are not adversely affected (monetary or service requirements) by the proposal.

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16.4.2 Asset Sharing

In circumstances when the DSR services has no detrimental impact on either party (NO or SO), the framework proposes that an ‘Asset Sharing Path’ is most appropriate.

A circumstance when the resource sharing path may be utilised is outlined below:

The SO energy reserve products, Network Operator post-event service:

Both parties require access to the DSR resource with a single dispatch of the resource meeting both parties requirements; no detrimental impact.

In this situation the SO has a window of need (e.g. a balancing services window) but doesn't know when the need may occur. Likewise the NO knows there will be a need to use the DSR for a fault on the system but doesn't know when a fault may occur. Here there is no need for either party to hold the DSR from the other party as the DSR use could be mutually beneficial.

The key benefit of this approach is that the DSR resource is being used by multiple parties, negating the need for each service provider to procure additional DSR services and enabling more efficient use of the DSR resources providing increased value for money for end consumers.

The framework also proposes:

- separate contractual arrangements between the DSR service provider and the relevant network companies;
- separate procurement strategies for the procurement of DSR services by the network companies;
- separate dispatch mechanisms for utilisation of the DSR services by the network companies;
- clearly defined data exchange arrangements between the DNOs and the DSR service provider;
- clarity that the DSR resource is flexible and capable of fulfilling the contractual requirements of both the DNO and SO;
- clearly defined and complementary contractual arrangements (inclusion of any data sharing requirements) between the DNO, SO and the DSR service provider;
- clearly defined monetary flows for the payment of the DSR service by the appropriate network company and
- clarity as to when the electricity market accounts for the DNO use of the DSR resource.

16.5 Demand Side Response Shared Services Framework Concept Paper

The consultation published in April closed on the 16th May with responses to all those that provided comments completed by the end of the summer 2014. The original published document can still be downloaded at the ENA Web Site:

http://www.energynetworks.org/modx/assets/files/news/consultation-responses/Consultation%20responses%202014/Demand%20Side%20Response%20Concept%20Paper_revised.pdf

At the time of authoring the interim FALCON report, the consultation responses had been received and were being collated by the group. It is the intention of the group to publish a 'next steps' document during the summer of 2014.

16.6 Next Steps

The participation of the CTL from FALCON in the Shared Services Group ceased at the end of **(S1)** following the completion of the consultation with industry to determine broader views on the proposals. The funding provided by Ofgem against the scope of the trials themselves did not extend to continuing the participation of the FALCON commercial expert to fully resolve the identified issues rather than identify and propose any potential solutions.

The group has continued to meet over the subsequent year during which **(S2)** was carried out with the results available to help with continued advancement of a workable concept for multi-party access to assets. If successful the development of a shared services framework will provide benefits to consumers by:

- revealing the true value of DSR from a network perspective;
- clarifying interaction between network companies;
- raising awareness of market opportunities to (new and existing) DSR providers; and
- Facilitating increased accessibility of DSR resources to the electricity market.

The proposed DSR shared service framework provides a pragmatic approach for developing the DSR market and ensuring that the value of DSR is accessible by the various market participants.

This consultation aims to seek the views of stakeholders (industry and non-industry) as to whether the ENA Electricity Demand Side Response Shared Services group has considered the issues and proposed pragmatic solutions to removing the current barriers to the multi-party use of a DSR resource.

The group is minded to take some or all of the following steps, contingent upon whether significant issues are identified within the consultation responses or not:

Develop a common framework

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The group will consider whether to and/or how to combine the two shared service framework paths into a common framework. This could include, but not limited to, the following analysis:

- assess impact of DSR shared services framework pathways on existing processes;
- consider amendment options to existing contractual and commercial arrangements;
- clarify through desk top analysis the appropriate arrangements in the common framework.

Understand the changes required to implement the proposed framework

The group will develop a sensible delivery approach to implement the common framework taking into consideration how to engage with all stakeholders and embed the new arrangements. The group believes that this task is achievable.

Develop an implementation plan, potentially testing the proposed framework in the electricity market through a trial

The group proposes to consider the development of a pilot study, potentially under an innovation funded project, which will test the delivery approach before developing a full deployment implementation plan.

SECTION 17

Distribution System Operator

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There is a great deal of discussion across the energy market and beyond as to the expectation that a DNO will start to make the transition to becoming a DSO. The two terms sound very similar but they in fact are very different in terms of the roles and responsibilities that are associated with the two different organisational types.

There are several factors acting as catalysts within the developing energy and smart grids market that support the view that DNOs are well positioned to take a greater proportion of operational responsibility for the efficient use of energy. This will require a very extensive advancement in skills, resources and regulatory conditions to incorporate all the extra duties that would be expected of a DSO over and above the current DNO obligations to manage the delivery of electricity. Confusion can sometimes exist between the two terms as there is a lack of consistency across international markets, as some already use the term DSO for the role that is defined within the UK as a DNO.

The functions of a DSO include all those that are currently fulfilled by DNOs but with added obligation to actively optimise the network in much the same way that The SO does currently on a National basis and potentially incorporating aspects that would currently be the interest of suppliers. The table below outlines just some of the additional functions that implied that a DSO would be obliged to manage.

Table 28 - DNO vs DSO responsibilities

Service	DNO	DSO
System Monitoring	X	X
System Automation	X	X
Fault Level Management	X	X
Voltage / Power Factor Control	X	X
Energy Storage		X
Distributed Generation connections	X	X
Energy Management / Forecasting		X
National Balancing Participant		X
Distribution charging	X	X
Multi-Rate Time-of-Use Tariffs		X
Dynamic Tariffs with increased locational granularity		X
Local Balancing Services		X
Distribution Network Constraint Management	X	X
System Security	X	X
Local Energy Markets		X
Demand Side Response		X
Aggregation services		X
Generation operator		X
Energy trading		X
Heat Networks		X

Two of the most compelling factors that are often cited as giving the impetus for change are the growing interest in DSR and a nationwide rollout of smart meters, particularly within the domestic customer environment. This is because the role of users is also expected to change and customers will be expected to become active components of the network operation and management, with increased benefits available to those who can offer flexibility within the way they consume and / or generate. Naturally, this will require significant improvements in the understanding of users' requirements, enhanced network communications, alterations to regulation and advanced operational systems. This will take some time, but it is possible that provision of DSR will act as a transitional service and stimulate some of the more complex and structurally entangled to aspects of the current market to evolve.

DNOs themselves are also now finding that the change in the current UK generation mix where much of it is distribution connected, is also providing a more direct justification as to why they should embrace the transition to having full DSO capability. However this statement in itself can be quite misleading as the suggestion from this is that the process of change will result in the cessation of the DNO in order to become a DSO. The initial view of the role of the DSO by DNOs appeared to be that it is a large business transformation process, which raises concerns. These concerns appeared to derive from the lack of readiness for such a metamorphosis and the perceived impact of it on the conventional business areas.

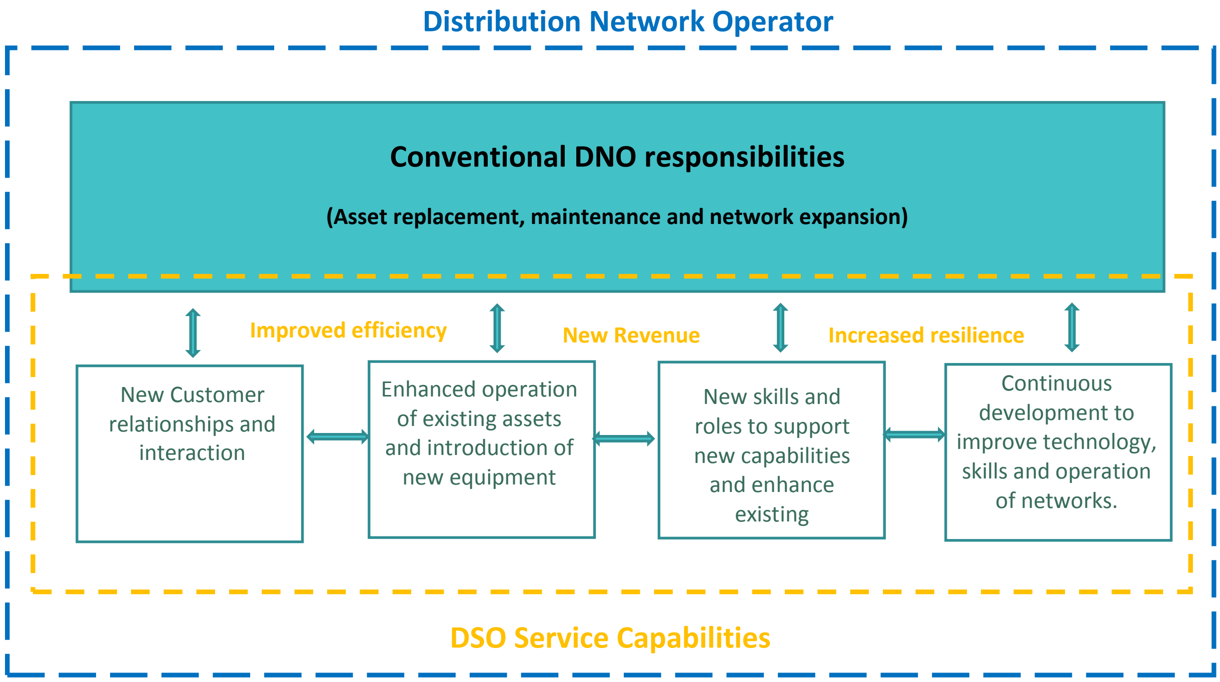
The DNO's role has been developed primarily on the principal of managing assets and providing a passive conduit to the flow of energy for a centralised generation system. Traditional network topology has both transmission and distribution functions not only passive but with a single direction of flow carrying electricity from large and often remote generation to consumers. Consequently, infrastructure was able to be predominantly static in its operation due to the simple and predictable nature of its function. As a result the networks have largely been over engineered to accept periods of maximum demand with in many cases at least 100% redundancy achieved throughout large portions of the network. Several reasons now exist why this approach cannot be reasonably maintained as an enduring strategy in light of industry and market wide developments to energy:

- Requirement to actively manage power flows that can be highly variable and may result in reverse power flows
- Incorporation of many new processes and technologies that allow increased value to be extracted from existing assets e.g. ANM (Automated Network Management) and DSR (Demand Side Response).
- Regulator incentives for sweating of assets and improved utilisation without significantly increasing perceived risk to supply.
- Increase of meshing and active operation.
- Ability to accept increased levels of generation connections to the Distribution level networks.
- Increased downstream information flows from energy user and upstream to generators and transmission network.

- Improved analysis and forecasting of network utilisation.
- Voltage management within the context of increased activity
- Increased efficiency and reduced carbon impact.

It is probably therefore more helpful if 'DSO' is recognised as a range of capabilities offered through a set of new skills and technologies rather than an entirely separate entity to the DNO. It is however imperative that it is recognised that the function of the current DNO does not disappear with the range of increased responsibilities and objectives. Even where added value and flexibility is expected from their assets the current responsibilities of managing and maintaining these remains.

All of the UK's DNOs are highly proficient in engineering terms and their ability to manage and maintain their assets and typically achieve the majority of their conventional performance metrics. A significant aspect of the difficulty that will be incurred within the development of new DSO capabilities will be within the culture, commerciality and existing organisational structures. In many cases it will be most apparent as the current range of skills will not alone be adequate to meet the increased responsibilities of the new organisational functions.



SECTION 18

Internal Change Request

The learning achieved during **(S1)** offered an opportunity to for WPD to agree a variation to the final DSR operational trials in winter 2014/15.

As highlighted in section 16, the DSR Shared Services group have presented a principal for asset sharing that project FALCON is able to incorporate into the remaining tenure of the trials. This will help the industry develop an accelerated understanding of potential issues and viability the group proposals.

The inclusion of testing a new model will require a number of additional scope alterations. Three alternatives were therefore presented for approval to ensure adequate value would be achieved.

Table 29 - scope alteration options

No.	Title	Overview	Impact – learning
1	Re-run 2013/14 trials	Run same **T6** (DG) trials as before using same participants as generation fuel types and sizes and customer profiles achieved and no additional learning is likely to be gained. Re-open recruitment drive for **T5** (turn down) Maintain £300pMW payment Replace Elster smart meter with one that works	Direct comparison of the 2013/14 trials (with exception of **T6** recruitment) Minimal additional learning Potentially no Demand turn down Will take into account new aggregators
2	Re-run 2013/14 trials and Increase payments to customers	Run same **T6** (DG) trials as before using same participants as generation fuel types and sizes and customer profiles achieved and no additional learning is likely to be gained. Re-open recruitment drive for **T5** (turn down) Increase payments from £300pMW to £600pMW Replace Elster smart meter with one that works	Minimal cost to project Direct comparison of the 2013/14 trials (with exception of **T6** recruitment) Minimal additional learning Potentially no Demand turn down Will take into account new aggregators Assesses whether increasing costs motivates participants to **T5**, Turn down
3	Trial elements of DSR shared services report	Week ahead notice rather than 30 min notice Measure customer performance by capping import or minimum export rather than a delta measurement. For **T6**, offer existing participants opportunity to take part Re-open recruitment drive for **T5** (turn down) Trial two different types of smart meters Increase payments from £300	Implements elements of the Shared Services group report in a timely manner, which no other DNO is doing Reduces the ability for customers to ramp up load to glean as much payment from FALCON as possible Maximises learning and implements industry learning Potentially no Demand turn down Will take into account new aggregators

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No.	Title	Overview	Impact – learning
		MWh to £600 MWh	

Option **three** was selected and approved, resulting in the addition of the following key objectives for delivery. The next steps are to:

- Present changes to scope to participants and aggregators;
- Confirm ongoing participants subject to programme changes;
  - Week ahead notification of DSR schedule;
  - Capped demand / Minimum export metering model;
  - Additional smart meter installation;
  - New contract;
  - New Payment model;
  - Double **T5** payment to £600 MWh;
- Open participation to other aggregators;
- Recommence recruitment for **T5** and any outstanding **T6** capacity requirements;
- Develop new performance contract;
- Author new performance algorithms
- Develop new back office software and
- Establish new learning objectives and additional methodology for analysis.

SECTION 19

Appendices

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19.1 Definition of DSM / DSR and the Marketplace

Demand Side Management (DSM) and Demand Side Response (DSR) seem to be regularly mistaken and confused with each other. For the purposes of clarity, and to ensure that the correct nomenclature is both understood and adopted in relation to the terms DSM and DSR, the correct definitions are provided below.

Energy demand management, also known as Demand Side Management, is the modification of consumer demand for energy through various methods, such as financial incentives and education. Usually, the goal of DSM is to encourage the consumer to use less energy during peak hours, or to move the time of energy use to off-peak times such as night-time and weekends. Peak demand management does not necessarily decrease total energy consumption, but could be expected to reduce the need for investments in networks and/or power plants for meeting peak demands. An example is the use of energy storage units to store energy during off-peak hours and discharge them during peak hours. The provision of DSM can also more broadly be regarded as any change of activity or behaviour from sites connected directly to the distribution network. This includes but is not limited to:

- Energy Efficiency / Reduction;
- Energy Storage;
- Distributed Generation;
- Dynamic Pricing;
  - Time of Use (ToU)
  - Location of Use (LoU)
- Smart Metering;
- Increased or Flexible demand devices (Electric Vehicles and Heat Pumps);
- Dynamic Demand; and
- Demand Side Response (DSR).

The term DSM was coined following the time of the 1973 energy crisis and 1979 energy crisis. Demand Side Management was introduced publicly by Electric Power Research Institute (EPRI) in the 1980s. Nowadays, DSM technologies become increasingly feasible due to the integration of information and communications technology and power system, resulting in a new term: Smart Grid.

You will note from the list provided, that DSR can be regarded as a sub-set of DSM.

Demand Side Response is defined as “actions voluntarily taken by a consumer to adjust the amount or timing of their energy consumption”. Actions are specifically in response to a dynamic signal, and not to be confused with DSM behaviour incentives to follow predetermined price incentives. DSR is a reduction in demand designed to reduce peak demand or avoid system emergencies. Hence, DSR can be a more cost-effective alternative than adding generation capabilities to meet the peak and or occasional demand spikes. The underlying objective of DSR is to actively engage customers in modifying their consumption in response to programme providers' signals.

19.2 Purpose of DSR

In electricity grids, DSR is similar to dynamic demand mechanisms to manage customer consumption of electricity in response to supply conditions, for example, having electricity customers reduce their consumption at critical times or in response to market prices. The difference is that DSR mechanisms respond to explicit requests to reduce demand, whereas dynamic demand devices passively shut off when stress in the grid is sensed through automated sensors monitoring parameters such as frequency or voltage. DSR can involve actually curtailing power used or by starting on-site generation which may or may not be connected in parallel with the grid. This is quite a different concept from energy efficiency, which means using less power to perform the same tasks, on a continuous basis or whenever that task is performed. At the same time, demand response is a component of smart energy demand, which also includes energy efficiency, home and building energy management, distributed renewable resources, and electric vehicle charging.

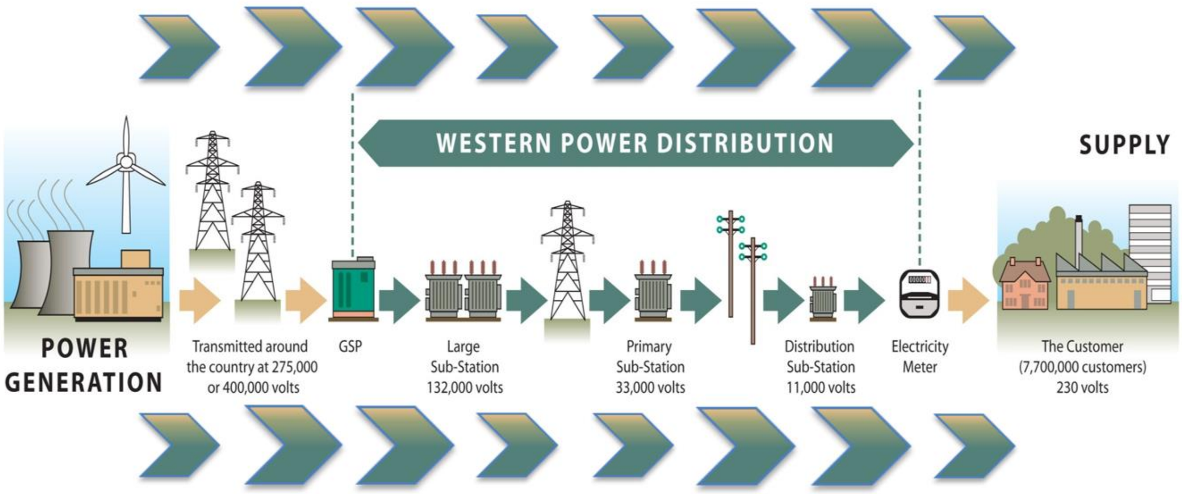
Current UK DSR schemes are typically implemented with industrial and commercial participants, often through the use of dedicated control systems to shed loads in response to a request by the System Operator. Services (pumping, heating, air conditioning) are reduced according to a pre-planned load prioritisation scheme when instructed to respond. An alternative to load shedding is on-site generation of electricity to supplement the power grid.

DSR will typically reduce demand for various reasons which are specific to the programme provider, thereby reducing the peak demand for electricity for limited periods. Since electrical generation and transmission systems are generally sized to correspond to peak demand (plus margin for forecasting error and unforeseen events), lowering peak demand reduces overall plant and capital cost requirements. Depending on the configuration of generation capacity, however, demand response may also be used to increase demand (load) at times of high production and low demand. Some systems may thereby encourage energy storage to arbitrage between periods of low and high demand (or low and high prices). This type of DSR, sometimes known as 'Footroom' is out of scope for the FALCON trials.

There are three types of demand response - emergency demand side response, economic demand side response and ancillary services demand side response.

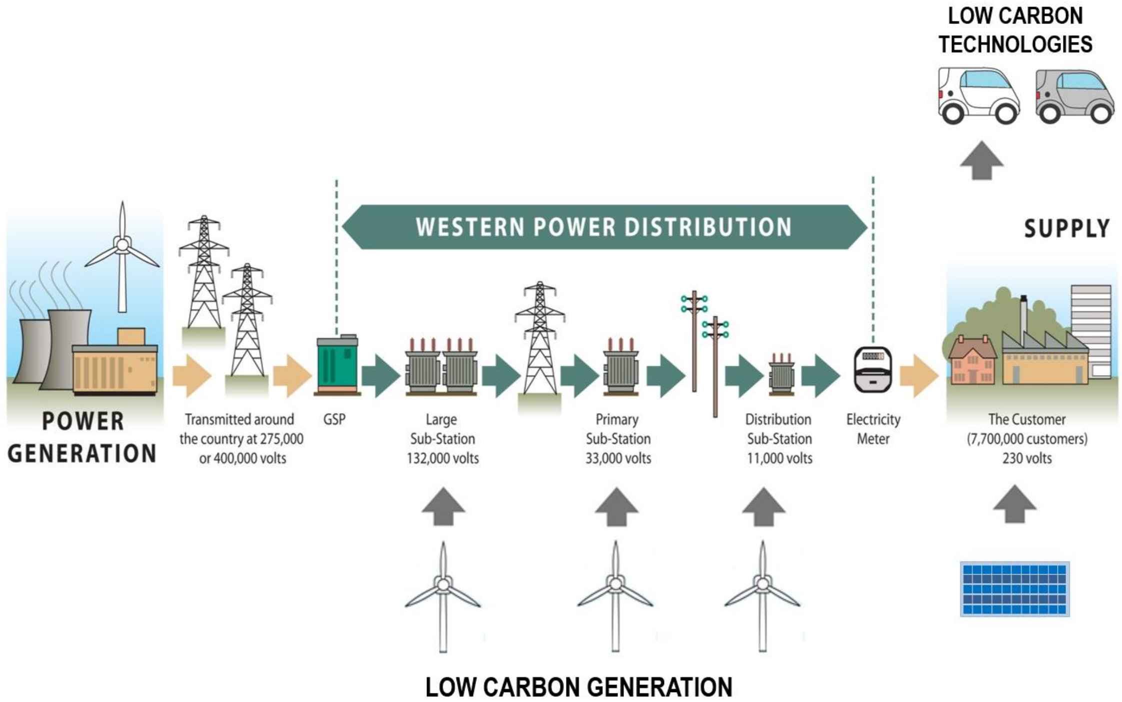
- Emergency DSR is employed to avoid involuntary service interruptions during times of supply scarcity. This may result from the failure primary plant such as a power station or wind farm and is not necessarily only applicable when annual system peaks occur. It may also be the case that this does not relate to a commodity shortage but instead a constraint that affects the ability to supply a specific geographic location. This is often overlooked as a form of DSR, as its primary purpose is to maintain continuity and the signal that is being responded to is generally either loss or threat of loss to the primary supplies.

- Economic DSR is employed to allow electricity customers to curtail their consumption when the product or convenience of consuming that electricity is worth less to them than paying for the electricity. Schemes of this nature are mostly focussed on benefits of trading and arbitrage and most likely to be operated by suppliers. It is expected these will increase in capacity in participant volumes significantly over the coming years as suppliers learn how to harness its value.
- Ancillary services DSR consists of a number of specialty services, as outlined in section 6.3. These services are needed to ensure the secure operation of system balancing and transmission. Some of these services have traditionally been provided by generators.



Different programme operators seek to achieve different impacts when they dispatch an instruction to participants to either increase generation or drop demand. This is likely to increase significantly in its use by all parties as we experience further development of Smart Grids. The above diagram represents an outdated view of the networks, where the expectation was that almost all generation occurred in large centralised plant and fed in a single direction without any great complexity. With many drivers including securing future energy supplies and encouraging more sustainable living, the networks require to adapt to the perpetually changing landscape.

In the past there were predictable loads served by large centralised generation. We now have increased variability in both load and, potentially, direction. As shown in the following diagram, current networks have solar and wind generation connected throughout the network at a range of voltages that are often convenient as a point of connection, but not necessarily beside a source of demand. The power flows therefore a greater level of monitoring and control to safely and efficiently operate the networks.



This supply challenges are further compounded by the undefined future demand profiles as we see further expansion within the electrification of transport and heating. It is therefore likely that interest will also swell as to how best the competing challenges of supply and demand can be used in a complimentary fashion through voluntary or mandatory schemes.

19.3 Current market

The current opportunities to offer DSR in the UK are generally focused on participation by the industrial and commercial sectors. The potential of the domestic properties is expected to be leveraged on the roll out of smart meters and is likely to still be several years away. The focus of this section is therefore restricted to considering either current or expected programmes aimed at primarily non-domestic involvement and its impact on the 11kv WPD network in the FALCON trials area.

DSR opportunities are typically operated as a performance contract with a small number of different models already being available within existing programmes. There are, however, a variety of potential 'use cases' for different actors within the energy industry. National Grid in the role of The System Operator, is currently the most mature programme provider and has utilised DSR in various forms for more than ten years. DNOs and suppliers can also potentially benefit from DSR programmes that may appear similar, however are being used for entirely different purposes. A third significant actor is expected to develop within the marketplace over the next few years as suppliers develop their own strategies to gain benefit from the potential efficiencies they can offer. With such different requirements it is possible that some services will be able to be operated alongside one another but it is more likely that conflicts will result in a shift from current conditions to one where increased participation is driven by escalating incentives.

Current programmes are not aimed solely at relatively small demand side contributors and still represent a minority within an increasingly competitive market. This market can include merchant power stations, dedicated farms of diesel generation and sizeable capacities from very large industrial consumers. Over recent years, over stimulation of the new demand side opportunities at a time when many merchant power stations were also shifting capacity into this area has driven down the rates for participation dramatically.

The broad spectrum of participant types has, however, created a diverse range of capabilities with variations around price, speed, volume, duration and locations. Some of these capabilities may be of varying value in different programmes and there might be conflicts in offering availability to multiple programme operators. Section 6.3 below provides context around the existing opportunities and some of the general conditions they require to be met to qualify.

19.4 Existing programmes

Contained in this section is a high level summary of fully operational, existing programmes that can currently be participated in by sites connected to the distribution portion of the network. The information provided is indicative and may be subject to changes by the individual programme operators or other parties. If you require more detailed information on any of the programme requirements and incentives please contact the provider detailed.

19.4.1 Triad or TNUoS avoidance (Transmission Network Use of System)

National Grid TNO (Transmission Network Operator)

The "triad" system is the means by which industrial and commercial electricity consumers' pay for the electricity transmission network in Great Britain. The triad system doubles up as a peak load management mechanism. Triad charges are part of Transmission Network Use of System (TNUoS) charges, which National Grid recovers every year from Licensed Generators (23%) and Licensed Electricity Suppliers (77%). The TNUoS charges which Electricity Suppliers pay for the consumption of their half-hourly (HH) customers are in the form of triad charges. The cost of owning and operating the transmission network is driven by the peak demand which the network must satisfy, (National Peak Load), and is higher where demand is high and generation is insufficient. The triad charging system has been designed to penalise consumption during peaks, especially in highly stressed parts of the network.

This encourages participants to optimise their demand or generation thereby mitigating their contribution towards the system's peak load. Peak loads are three HH periods on three days during a time period of five months each year (Nov-April). These three HH periods typically occur between 4.30 and 6.00pm. It takes 15-20 events during the five month period to contribute to peak shaving on triad days and for the participants to receive discount with 1kW granularity.

The “triad season” runs from the beginning of November to the end of February every year. Once the triad season is over and half-hourly meters have been read, the three half-hour periods of maximum demand are identified. It is expected most parties involved will require to act in 15-20 events during the five month period to achieve reductions on the three HH eventually declared. Prediction in advance is further complicated by the need for the three HH triad periods to be separated by at least ten clear days.

For each Electricity Supplier, its customers’ average consumption, in each network zone, over the three triad periods, is calculated. This is multiplied by the triad charge for that zone to create the total amount which the Supplier must pay to National Grid. The charges associated with TNUoS can appear to be disproportionate as during these three 30 minute periods with real terms increase from typical charges of as much as 10,000% depending on location and how a site procures its electricity. It is for this reason that over 1GW of capacity is minimised by participants’ seeking to reduce their usage and/or maximise export whenever there is a high expectation of National Peak Load being neared.

The 1GW reduction is made up of customers who are reduce their energy consumption during periods that are have a high potential of being declared as one of the three annual peaks. For some sites this is done by simply avoiding consumption during such periods, while others will use any on-site generation to supplement or avoid the mains supply from which the TNUoS charge is calculated. It is also possible to earn incremental revenue with the same level of disproportion in the event that the site has excess generation capacity and can export to sell the TNUoS benefit to an energy purchaser as part of their PPA (Power Purchase Agreement).

19.4.2 STOR (Short Term Operating Reserve)

National Grid - SO (System Operator)

Short Term Operating Reserve is one of National Grid's most important tools for securing the national electricity system in real time. It is also the most common and widely known UK DSR programme. In order to balance the supply and demand of electricity on short timescales, the UK National Grid has contracts in place with generators and large energy users to provide temporary extra power, or reduction in demand. These reserve services are needed if a power station fails for example, or if forecast demand differs from actual demand. National Grid has several classes of reserve services, which vary in several respects, bust most critically the speed and volume with which they can respond when required.

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The fastest acting are frequency services, followed by Fast Reserve and then STOR. The response times for this service start at six minutes and extend out to as much as two hours, although such variability is reflected in both the prices and quantities that are accepted during the tendering exercises.

Under the STOR arrangements, National Grid pays a 'rent' (termed 'availability') for STOR capacity to be kept exclusively available during certain periods, and pays further a usage charge (utilisation) when the reserve is dispatched, such as during demand peaks, or when large power stations fail.

STOR is a year-round service, available to National Grid on a 24-hour basis, although most participants restrict their provision to The SO defined premium periods for which availability payment is offered. Availability is paid during key 'windows' where the system experiences rapid load change or peak demand. These windows vary seasonally, but generally fall within the period 07:00 to 22:30, and amount to roughly 11 hours per day. Most STOR utilisation occurs within these windows.

The STOR market has been growing in volume and overall value for several years, due to the reduction of flexible coal and oil electricity generation capacity, and the increase in forms of generation which can require increased levels balancing, such as renewables.

STOR is subject to a number of restrictions and conditions which include a minimum capacity threshold of 3MW. Above this capacity it is possible to tender directly to National Grid for the provision of STOR services or via the assistance of an agent. Prospective providers can choose to use an Agent to administer their tender process and, on their behalf, submit STOR Tenders to National Grid. National Grid perceives the role of an Agent as essentially a "go-between", interfacing with both the prospective Reserve Provider and National Grid. National Grid is willing to deal with Agents provided that no part of the tender process or contracting process is hindered. It should be noted that using an Agent (or not) does not affect evaluation of STOR Tenders.

The alternative option for sites that either don't have the 3MW minimum capacity at a single location or would rather defer the operational responsibilities to a specialised third party service provider. The role of an Aggregator is to develop and operate multiple sites (STOR Sub Sites) and offer these to National Grid as single STOR Site(s). This role is specifically different to that of an Agent.

Whilst an Aggregator can be an asset owner, typically an Aggregator will act on the behalf of one or more third party asset owners to submit "composite" STOR Tenders to National Grid. National Grid therefore perceives the role of an Aggregator as essentially a "Reserve Provider", holding the STOR Contract itself whilst managing the necessary interfaces with the various individual asset owners. The role of aggregators vs direct service provision is explained in greater detail in section 8.2 of the report.

Further information on STOR can be obtained from the National Grid's web site, including detailed requirements, joining instructions and market information.

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http://www2.nationalgrid.com/uk/services/balancing-services/reserve-services/short-term-operating-reserve

19.4.3 FCDM (Frequency Control by Demand Management)

National Grid - The SO (System Operator)

System frequency is a continuously changing variable that is determined and controlled by the second-by-second (real time) balance between system demand and total generation. If demand is greater than generation, the frequency falls while if generation is greater than demand, the frequency rises.

National Grid has a licence obligation to control frequency within the limits specified in the 'Electricity Supply Regulations', i.e. ±1% of nominal system frequency (50.00Hz) save in abnormal or exceptional circumstances. National Grid must therefore ensure that sufficient generation and / or demand is held in automatic readiness to manage all credible circumstances that might result in frequency variations.

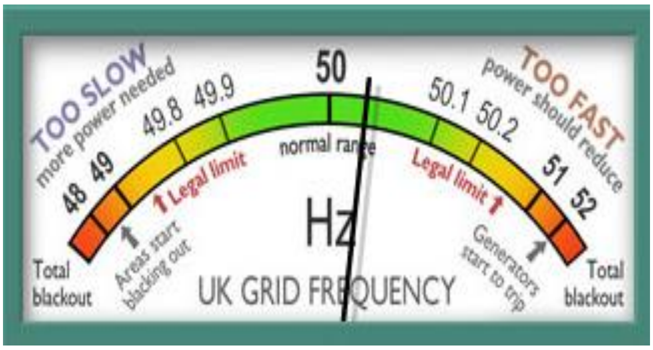

Figure 42 - indicator for National System Frequency

FCDM is required to manage large deviations in frequency which can be caused by, for example, the loss of significantly large generation. The service is a route to market for demand-side providers, and compliments other non-dynamic service provisions. The electricity demand is automatically interrupted when the system frequency transgresses the low frequency relay setting on site.

A FCDM participant must provide the service within two seconds of instruction and maintain delivery for minimum 30 minutes. Restrictions include minimum 3MW capacity which may be achieved by aggregating a number of small loads, typically at same site. This can be at the discretion of National Grid if contracting directly but can also be facilitated by aggregators. The role of aggregators vs direct service provision is explained in greater detail in Section 8.2 of the report.

Bid available capacity for load shedding based on bilateral contracts, triggered by drop in system frequency to a pre-agreed set point. The participant is rewarded only for availability not the utilisation. Events typically occur at up to ten occasions per year but failure to deliver diminishes all availability revenue. Suitable metering, an output signal and a type approved trigger relay are required in order to offer service.

Further information on Frequency Control by Demand Management can be obtained from the National Grid's web site, including detailed requirements and joining instructions.[6]

http://www2.nationalgrid.com/uk/services/balancing-services/frequency-response/frequency-control-by-demand-management/

19.4.4 FFR – Firm Frequency Response

Firm Frequency Response (FFR) is the firm provision of Dynamic or Non-Dynamic Response to changes in Frequency. Unlike Mandatory Frequency response which is a necessary ruling for large power stations un the 'grid code', FFR is open to BMU and non-BMU providers, existing Mandatory Frequency Response providers and new providers alike. National Grid procure the services through a competitive tender process, where tenders can be for low frequency events, high frequency events or both.

The minimum level is 10MW. This may be from a single unit or aggregated from several smaller units. If a new participant has less than 10MW but are expecting to reach this threshold in the near future, they may be able to participate through a separate route.

A compatible frequency sensitive relay needs to be installed and supplied by the participant. No specific provider is recommended, although the minimum requirement is that the relay needs to be within a 0.01Hz tolerance.

In order to demonstrate that the service is being provided, a live communications method in necessary as data needs to be sent to National Grid, either second by second or at National Grid's discretion, minute by minute. If minute by minute, this may be provided through the STOR SRD system (if the provider participates in STOR). For minute by minute data, additional post event second by second data needs to be sent to National Grid so that the provider's performance can be verified.

In accordance with the Grid Code, for a Low Frequency (LF) service i.e. an increase in output, this can be either primary (full output within 10s sustained for further 20s) or secondary (full output within 30s, sustained for 30min). For a High Frequency (HF) service, this needs to be achieved within 10 seconds and sustained indefinitely.

There is a dead band of +/-0.015Hz where response does not need to be provided.

At the moment, we do not stipulate a minimum run time. However, if there is a limitation to your plant which requires a minimum run time, then this can be included in your tender. Please note that any limitations provided may impact the valuation of your tender i.e. make it less beneficial.

FFR is procured via a competitive tender process which runs once a month. The first business day of each month is the deadline for services starting on the following month. The requirements for each service vary by time of day (demand profile) and plant on the system. There is a guide to general requirements in the Market Information Report. Response is required 24/7 so a tender that covers any time period could be valuable. In general Primary and Secondary or Secondary only services are more valuable during the daytime because they offset margin costs which are not typically incurred overnight.

Main fees:

Availability fee (£/hr) – for making the service available to National Grid

Nomination fee (£/hr) – for being called upon to provide the service

As this is a 'Firm' service, National Grid does include a penalty structure for delivery below the contracted standards. If the unit is deemed to be underperforming, this will lead to a deduction in all nomination and availability fees, attributable to all settlement periods in the FFR nominated window in question. The formula for calculating this is below:

C/D * 100

C = highest level of generation

D = contracted response

Percentage Performance Measure	*Percentage Deduction in Fees*
≤10%	100%
≥10% to <60%	50%
≥60% to <95%	25%
≥95%	0%

19.4.5 Energy Trading and Fuel Arbitrage

Energy trading and fuel arbitrage are opportunities only pursued by a small number of participants in the current UK market. There is a relatively high risk, as with other trading environments, they carry risks over and above those that are incurred in the provision of ancillary services programmes. The risk element in most service arrangements are limited to the loss of opportunity to earn or relatively small penalties in the event of delivery failure. When trading energy it is important that a site completes the action that was associated with their final 'position' in order to complete the transaction. This will generally involve agreements in relation to consumption of fuel, production or consumption of electricity. If the site fails to comply with the arrangement that were made in advance the exposure to negative costs can be of a magnitude many times more than the potential earning that were available. This is a specialist type service that is going to be attractive to some niche sites

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with advanced understanding of their energy needs and a great deal of operational flexibility.

On this basis we will not reviewing the opportunity in great detail as it is likely that it will be restricted to a small number of participants for the short term, and will only expand if energy pricing and market volatility increase significantly, improving the opportunity rewards for trading fuels and / or electricity.

19.5 Further Opportunities

19.5.1 DSBR (Demand Side Balancing Reserve)

National Grid – The SO (System Operator)

DSBR is targeted at non-domestic consumers able to reduce/shift demand or run 'behind-the-meter' standby generation, and owners of small embedded generation or storage accruing to a supplier's consumption account. DSBR can be provided by non-domestic consumers directly or by third parties, including suppliers, aggregators or other intermediaries.

DSBR is not intended for those consumers who already reduce/shift demand or run embedded generation during peak times on winter weekday evenings in response to pricing signals Those with committed STOR contracts or participating in Triad avoidance.

DSBR can be provided by sites which are half-hourly metered and subject to the BSC settlement arrangements (i.e. > 100kW). A DSBR Unit represents one or more such sites providing the service with an minimum aggregated capacity of 1MW.

DSBR providers declare their capability to reduce demand (or increase generation output) against a baseline demand profile for at least one hour between 4pm and 8pm on working weekdays in the months of November to February, having been given at least two hours notice. The initial requirement that was being sought by National Grid was for added resilience for the two winters from 2014 -16 which would be allocated via two separate annual tender processes.

'The volume requirements determined for this time period are set out below:

Table 30 - DSBR annual volume requirements

Year	Maximum De-rated volume
2014/15	330MW
2015/16	1,800MW
2016/17	1,300MW
2017/18	800MW

These represent the maximum de-rated volumes required. The actual volume required will be that which delivers best value for customers, balancing costs against value of lost load in accordance with the methodology, and will depend of the prices submitted in the process tendered for these services. Note that these volume requirements are de-rated values, and the actual volume procured will depend on how individual DSBR and System Balancing Reserve, (SBR), resources are de-rated. For example, if at 2014/15 requirement is met by DSBR, it is proposed to de-rate initially to 75%, and the actual volume procured will be up to 440MW in order to meet the 330MW de-rated requirement.'

An online portal is available to allow service providers to register and tender individual DSBR Units made up of individual Meter Point Administration Numbers (MPANs). Tenderers are invited to declare a quantity of demand reduction that could be delivered relative to their baseline demand profile during the settlement periods between 4 and 8 pm. This includes the quantity that could be delivered and the length of time it could be sustained within that window. They are required to break this down in order to specify the individual MPANs at each site that make up an aggregated DSBR Unit, and the capability offered through each individual MPAN. The baseline demand profile for each settlement period represents the typical demand of the DSBR Unit in the winter weekday evenings of system peak demand.

Tenderers indicate whether they wish to receive an optional setup fee to support them in establishing their demand reduction capability. This will be £10,000/MW (£10/kW) for demand reduction that can be sustained for at least two hours, and pro-rated for demand reduction that can be sustained only for a period of less than two hours (but greater than one hour).

They also tender the Utilisation Rate at which they would wish to be paid for reducing demand from a range of nominal rates ranging from £250/MWh (£0.25/kWh) to £12,500/MWh (£12.50/kWh). To encourage and support intermediaries such as Aggregators, Suppliers and Customer Portfolio players in recruiting / managing a large numbers of smaller sites, these parties may tender to receive an Admin Fee. Each DSBR Unit tendered must comprise >50 individual MPANs to qualify. This will be paid at the end of the winter season, unless the DSBR Unit fails a DSBR Performance Test.

Except for testing, DSBR Units will only be dispatched by the System Operator after all feasible offers and bids in the Balancing Mechanism have been used, or expect to be used, in balancing the system. However National Grid will not require to deplete its operating reserves and frequency response holdings before dispatching DSBR.

DSBR Units will be grouped into tranches defined by the tendered utilisation rate, with each tranche dispatched in ascending price order in order to demonstrate best value to the consumer.

DSBR Units may be dispatched outside the contracted service window, recognising that in such periods the full DSBR capability offered might not be delivered. They will not be dispatched outside the 4pm-8pm DSBR service window.

DSBR would normally be dispatched with at least 2 hours notice. However, DSBR may be dispatched with shorter notice periods if the need arises, recognising that some providers may not be able to respond at such short notice.

A DSBR dispatch instruction will specify the times between which the declared demand reduction capability should be delivered.

The dispatch system will utilise the online portal or an application that can be downloaded to a Smartphone or Tablet to receive DSBR dispatch instructions. The system will broadcast a dispatch instruction (and warnings) to the participants instructing the associated DSBR Unit(s) to reduce demand between two specified times. SMS messaging is also used to alert participants and individual sites of any dispatch instruction issued via the dispatch system.

The quantity of demand reduction delivered will be calculated from half-hourly settlement data. This equates to the difference between the actual metered demand (or output) of the DSBR Unit and the baseline demand profile, and will be calculated for each half hour of the event.

The baseline demand profile for each DSBR Unit is calculated as the average of the consumption or generation in the corresponding settlement period in the previous ten days of highest transmission system demand over the prior 12 months. The methodology automatically excludes any dates during which the participant site may have previously been called in a DSBR event.

Except under certain circumstances, the utilisation payment to each DSBR Unit will be calculated according to a stepped payment schedule whereby: the first 25% of demand reduction is not paid; the second 25% is paid at 50% of the nominal utilisation rate; the third 25% at 150% of the utilisation rate; and the last 25% being paid at 200% of the utilisation rate.

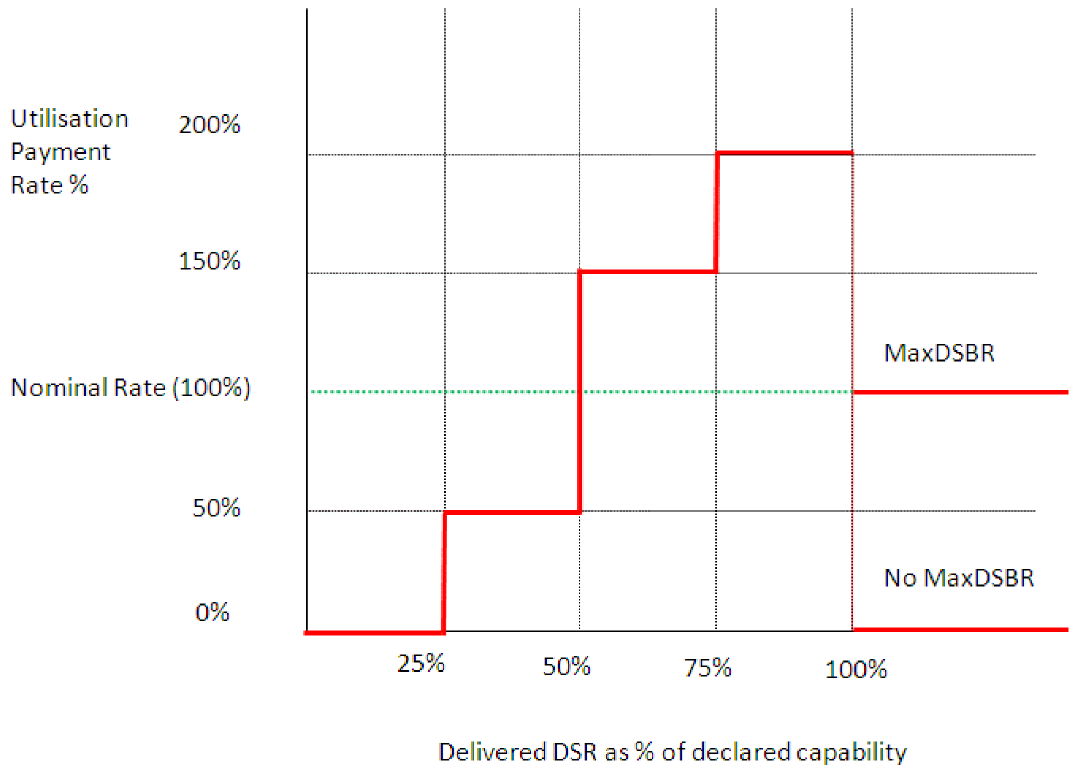

Figure 43 - variable utilisation rate

Demand reduction will be paid up to the declared capability at the nominal utilisation rate if called with less than two hours' notice, if called less than 2 hours after the last dispatch instruction ended, or was dispatched outside the contracted service window.

The costs of DSBR, including setup fees, utilisation payments and any admin fees will be recovered through BSUoS charges.

At the time of publishing of this report National Grid had published and were awaiting responses to a consultation document to measure opinion on their proposals to extend the DSBR service for a further two years to the end of winter 2018, ahead of the commencement of the Capacity Market volumes becoming available.

19.5.2 UK Capacity Market

The Capacity Market is one of the main building blocks of the UK Government's Electricity Market Reform (EMR) programme. Its goal is to ensure adequate capacity within an electricity system that in future will rely increasingly on intermittent wind and inflexible nuclear generation. To deliver a supply of secure, sustainable and affordable electricity, the UK needs investment in new generation projects and innovative technologies. But we must also get the best out of existing assets on the network. The Capacity Market aims to deal with both these issues by bringing forward new investment while maximising current generation and demand reduction capabilities.

Even though electricity demand is gradually reducing, the UK's peak demand isn't shrinking much, and is set to remain at around 53 gigawatts.

The UK has lots of old coal, gas and nuclear power plants. As they age, they get more prone to breaking, so if the power companies don't want to invest millions in upgrading them they usually shut them down. The government created the capacity market mechanism to ensure there will be enough power into the 2020s. It should ensure there's always enough electricity to meet peak demand, even when the weather prevents renewables from generating any power.

Only dispatchable energy providers can participate in the capacity market as they are designed to provide power around the clock. This will eliminate the majority of renewable providers as wind and solar generation do not have adequate control over their output as to guarantee its availability at times of greatest need.

The government will hold annual auctions to make sure there is adequate capacity available for future years, starting will supply for 2019. Power plants can bid to supply electricity, or energy intensive companies can offer to cut the amount of power they use, for a particular price.

The price is worked out using what's known as a 'descending auction'. The auction takes place over four days, with four rounds of bidding each day. In the first round, the government will offer companies £75 for each kilowatt of capacity they will guarantee to provide. The expectation which was companies to offer much more power than it needs at this high price. So it will reduce its offer by £5 in the next round, and every subsequent round, until enough companies drop out to make the bids add up to the capacity volume the government wants. Whatever the price is at that stage when the offered capacity has reduced to match the required volume will be the price companies remaining in the auction will be awarded. The government claims that through the bidding system, the UK should get its demand covered for the lowest possible cost.

Generators who are successful in the auction will benefit from a steady, predictable revenue stream (capacity payments) that encourages them to invest in new generation or to keep existing generation available on the system. The capacity obligation means they must be available to deliver energy when needed or face penalties. At the same time households and businesses up and down the country will benefit from greater security of supply.

The first Capacity Market auction took place in December 2014, and awarded a range of contracts for between 1 and 15 years duration, depending on the type of provider and whether it is new or existing plant. It should be noted however that DSR is not being offered contracts longer than one year. This has resulted in criticism of the structure of the capacity market auctions.

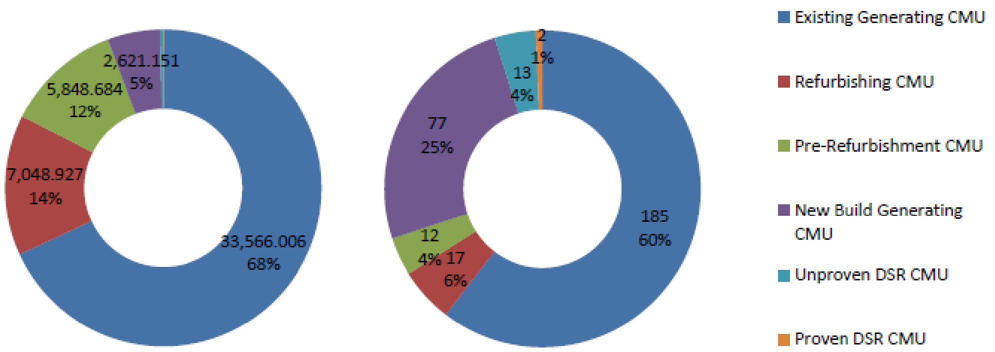

Figure 44 - awarded Capacity Agreements by Technology Type

Table 31: Auction Results Awarded by CMU Classification

	Capacity (MW)	Capacity (%)	Number of CM Units	Number of CM Units (%)
Existing generating CMU	33,566	68.14	185	60.46
Refurbishing CMU	7,048	14.31	17	5.56
Pre-Refurbishment CMU	5,848	11.87	12	3.92
New Build Generating CMU	2,621	5.32	77	25.16
Unproven DSR CMU	165	0.34	13	4.25
Proven DSR CMU	8	0.02	2	0.65

Source: National Grid T-4 Capacity Market Results.

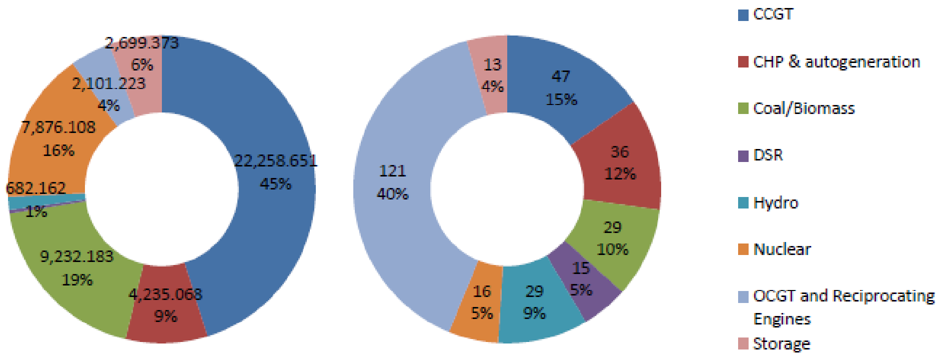

Figure 45 - Capacity Awarded by Technology Type

Table 32: Breakdown of Awarded Capacity by CMU Type

	Capacity (MW)	Capacity (%)	Number of CM Units	Number of CM Units (%)
CCGT	22,258	45.19	47	15.36
CHP & autogeneration	4,235	8.6	36	11.76
Coal / Biomass	9,232	18.74	29	9.48

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	Capacity (MW)	Capacity (%)	Number of CM Units	Number of CM Units (%)
DSR	174	0.35	15	4.9
Hydro	682	1.38	29	9.48
Nuclear	7,876	15.99	16	5.23
OCGT & Reciprocating Engines	2,101	4.27	121	39.54
Storage	2,699	5.48	13	4.25

Source: National Grid T-4 Capacity Market Results.

This initial competitive process secured 49.62GW of de-rated capacity at a clearing price of £19.40 per kW. Further auctions will take place each year to secure further short and long term contracts that should provide a greater certainty for investment into increasing generation and DSR capacity. Following the auction a statement was made by the Secretary of State for Energy and Climate Change.

"This is fantastic news for bill-payers and businesses. We are guaranteeing security at the lowest cost for consumers. We've done this by ensuring that we get the best out of our existing power stations and unlocking new investment in flexible plant."

The Capacity Market is a bit like an energy guarantee. It works by making sure that there is enough capacity available to meet peak electricity demand in the future. The first stage of this process has been to estimate how much capacity will be needed in 2018/19, which is the first year the Capacity Market will be running. Electricity providers have then bid into this capacity auction, promising if they win a contract that they will be available to provide electricity when needed. In return, they will receive a steady payment on top of the electricity that they sell. This reverse auction ensures consumers get the best deal possible as it drives bids down to the lowest level possible.

Through the auction, government has procured 49.26GW of capacity at a clearing price of £19.40kW. This will cost a total of £0.96bn (in 2012 prices), which works out at around £11 for the average household. However, previous modelling shows us that if a bill payer looked back over their bill in 2030 for the last 15 years then the impact of the Capacity Market would average out at £2 on their annual bill (in 2012 prices). This is because we expect average wholesale prices to come down with the security of a capacity market, compared to a world without one. Nothing will be paid by consumers before 2018/19.

The Capacity Market auction is just one part of the government's strategy to drive new investment and secure energy supplies in the short, medium and long-term. We estimate that more than £45bn was invested in electricity generation and networks between 2010 and 2013. And National Grid has already bought three additional power stations to keep in reserve for this winter and has begun buying extra capacity for next winter.

https://www.emrdeliverybody.com/cm/home.aspx

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19.5.3 Footroom (SO)

National Grid - SO (System Operator)

A relatively new concept, where instead of reducing demand or increasing generation, an opposite action is required. Initial trials for this service by aggregators are currently being developed but at the time of authoring this report there are no commercially operational sites being paid to take action.

Need will grow with volume of installed intermittent renewables such as solar and wind. Capability to absorb excess generation is most likely to be required for critical balancing during the night when normal demand is low. It is also expected that relatively substantial minimum capacities are necessary in order to be of practical value to the System Operator in order to address the issues. Early indications also highlight that there is likely to be particular geographic sensitivities that will require to be considered when contracting and may present additional complexity where an aggregated group includes broadly distributed locations amongst the participants.

19.5.4 Footroom (DNO)

DNO – Distribution Network Operators

Not yet commercially operative within the UK it is potentially more attractive to use Footroom services to manage geographical constraints relating to the excess generation that can be experienced due to clustering of renewable generation. This is particularly prevalent in Scotland and in the South West of England where it can be attractive for developers of larger scale wind or solar generation can more easily secure planning on lower cost land. Despite this mismatch with operational requirements they still receive the same levels of subsidy as they would otherwise gain if sited more appropriately to demand. The result of this can be excessive generation connected to networks with limited customers and an infrastructure that was never intended for the upstream movement of electricity. The distance that this electricity has to travel can often lead to requirements for expensive upgrades over long sections of network in order to shift the energy to consumers, over which the system inefficiency and losses increase.

As an alternative to conventional reinforcement it may be more economically viable for DNOs to develop DSR schemes that incentivise;

- Customers to increase demand during forecast periods where the expectation is that solar or wind will exceed demand
- Customer investment in storage to charge up during periods of low demand and discharge later
- Customers to reduce or cease dispatchable imbedded generation when in conflict with network conditions

It is expected that there will be innovation trials necessary that will be developed to define both the requirements and solution options.

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19.5.5 ToU (Time of Use) Tariffs

Electricity Supplier

Time of Use tariffs can be used as a pre-emptive method of managing the load on the system and will have impact in managing behaviour of users. As highlighted in section 22.1 there are key differences between DSM, where predetermined tariffs that alter and therefore predictable behaviour develops, and DSR, which is a dynamic response to an explicit signal. The current market for DSR in the UK doesn't generally offer mass market opportunities, where dynamic pricing signals result in meaningful volumes of demand or generation being shifted at short notice. There is, however, many supplier offerings based on time variable tariffs which can have an impact on DSR programmes with both positive and negative results. The supplier offerings can take a number of forms;

- ToU pricing where electricity prices are set for a specific time period on an advance or forward basis. This typically doesn't change more than twice a year. Prices paid for energy consumed during these periods are pre-established and known to consumers in advance, allowing them to vary their usage in response to such prices and manage their energy costs by shifting usage to a lower cost period or reducing their overall consumption;
- Critical peak pricing where ToU prices are in effect, except for certain peak days when prices may reflect the costs of generating and/or purchasing electricity at wholesale level;
- Real-time and dynamic pricing where electricity prices may change as often as half hourly. Price signal is provided to the user on an advanced or forward basis, reflecting the utility's cost of generating and/or purchasing electricity at a wholesale level; and
- Peak load reduction credits for consumers with large loads who enter into pre-established peak load reduction agreements that reduce a supplier planned capacity obligations.

In addition to the above, there are other time of day charging mechanisms operated by DNOs. These are explained in the following section.

19.5.6 DUoS (Distribution Use of System) Charge Avoidance

Distribution Network Operator

Every electricity customer's bill includes a Use of System charge. This is broken down into two elements. The first of these is the Transmission Network Use of System Charge (TNUoS). This is explained further in section 19.4.1.

The second element of the Use of System charge is the Distribution Use of System (DUoS) charge.

Distribution Use of System Charges cover the cost of receiving electricity from the national transmission system and feeding it directly into homes and businesses through regional distribution networks. The DUoS charge covers the costs of installing, operating and maintaining the regional distribution network, to ensure a safe and reliable electricity supply.

DUoS charges are made up of a variety of elements including:

- The availability/capacity supply charge
- Excess availability charge (applicable only if the agreed supply capacity is exceeded)
- Standing charge
- Reactive power
- Unit rates, which are split into three time periods; Red, Amber and Green. These charges vary per Distribution Company. Please see the chart below for the applicable time bands for each company.

Table 33 - DNO DUoS Zones & Times

DNO	Band	Weekday	Weekend
Western Power - Midlands, South West and Wales (EMEB and MIDE)	Red	16:00 - 19:00	
	Amber	07:30 - 16:00 and 19:00 - 21:00	
	Green	00:00 - 07:30 and 21:00 - 24:00	all day
Western Power - Midlands, South West and Wales (SWALEC)	Red	17:00 - 19:30	
	Amber	07:30 - 17:00 and 19:30 - 22:00	12:00 - 13:00 and 16:00 - 21:00
	Green	00:00 - 07:30 and 22:00 - 24:00	00:00-12:00, 13:00-16:00, 21:00-24:00
Western Power - Midlands, South West and Wales (SWEB)	Red	17:00 - 19:00	
	Amber	07:30 - 17:00 and 19:00 - 21:30	16:30 - 19:30
	Green	00:00 - 7:30 and 21:30 - 24:00	00:00 - 16:30 and 19:30 - 24:00
NorthEast (YELG)	Red	16:00 - 19:30	
	Amber	08:00 - 16:00 and 19:30 - 22:00	
	Green	00:00 - 08:00 and 22:00 - 24:00	all day
NorthEast (NEEB)	Red	16:00 - 19:30	
	Amber	08:00 - 16:00 and 19:30 - 22:00	
	Green	00:00 - 08:00 and 22:00 - 24:00	all day
London Power (LOND)	Red	11:00 - 14:00 and 16:00 - 19:00	
	Amber	07:00-11:00, 14:00-16:00, 19:00-23:00	
	Green	00:00 - 07:00 and 23:00 - 24:00	all day
Eastern (EELC)	Red	16:00 - 19:00	
	Amber	07:00 - 16:00 and 19:00 - 23:00	
	Green	00:00 - 07:00 and 23:00 - 24:00	all day

DNO	Band	Weekday	Weekend
South Eastern (SEEB)	Red	16:00 - 19:00	
	Amber	07:00 - 16:00 and 19:00 - 23:00	
	Green	00:00 - 07:00 and 23:00 - 24:00	all day
North West (NORW)	Red	16:30 - 18:30 and 19:30 - 22:00	
	Amber	09:00 - 16:30 and 18:30 - 20:30	16:30 - 18:30
	Green	00:00 - 09:00 and 20:30 - 24:00	00:00 - 12:30 and 18:30 - 24:00
Scottish Hydro (HYDE)	Red	12:30 - 14:30 and 16:30 - 21:00	
	Amber	07:00 - 12:30 and 14:30 - 16:30	12:30 - 14:00 and 17:30 - 20:30
	Green	00:00 - 07:00 and 21:00 - 24:00	00:00-12:30, 14:00-17:30, 20:30 -24:00
Southern Electric (SOUT)	Red	16:30 - 19:00	
	Amber	09:00 - 16:30 and 19:00 - 20:30	
	Green	00:00 - 09:00 and 20:30 - 24:00	all day
Manweb (MANW)	Red	16:30 - 19:30	
	Amber	08:00 - 16:30 and 19:30 - 22:30	16:00 - 20:00
	Green	00:00 - 08:00 and 22:30 - 24:00	00:00 - 16:00 and 20:00 - 24:00
Scottish Power (SPOW)	Red	16:30 - 19:30	
	Amber	08:00 - 16:30 and 19:30 - 22:30	16:00 - 20:00
	Green	00:00 - 08:00 and 22:30 - 24:00	00:00 - 16:00 and 20:00 - 24:00

The DUoS tariffs are calculated using a combination of two charging methodologies. The first methodology is called the (CDCM) and it is used to calculate charges to users who are connected to the LV and HV levels of the network. The second methodology is the EHV Distribution Charging Methodology (EDCM) and it is used to calculate site specific charges to users who are connected to the EHV levels of the network.

The methodologies are incorporated into the Distribution Connection and Use of System Agreement (DCUSA). This agreement governs the contractual relationship between DNOs and users of the networks. This agreement also sets out the methodologies and the procedure for interested parties to propose changes.

Both the CDCM and EDCM are common charging methodologies used across Great Britain by all DNOs. The methodologies were developed through joint collaboration between DNOs, Ofgem and interested stakeholders. The CDCM was implemented in April 2010 for both demand and generation users connected at LV and HV. The EDCM was implemented in April 2012 for demand users connected at EHV and in April 2013 for generation users connected at EHV.

While the methodologies are identical across all DNOs, the inputs to the methodologies reflect the characteristics of the network and the number and characteristics of consumers in each DNO area.

Charging commonality has brought a number of benefits to Suppliers and other users of the distribution networks. The biggest benefits have been:

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- The move from more than seven different charging methodologies for LV / HV tariffs and site specific charges to one for HV / LV and site specific;
- The consolidation of more than seven sets of tariff structures, including many legacy tariffs, to one condensed set of common tariff structures; and
- The incorporation of the charging methodologies into DCUSA so that any interested parties can bring forward change proposals through the governance process.

Since the incorporation of the methodologies, interested parties have initiated change proposals. These proposals have been progressed to bring further enhancements to the methodologies including changes to reduce volatility in the movement of tariffs from one year to the next.

Further information on each of the DNO's charging methodology can be found by accessing the following links:

Electricity North West –

http://www.enwl.co.uk/our-services/use-of-system-charges

Northern Powergrid –

http://www.northernpowergrid.com/downloads/system.cfm

Scottish Power Distribution and Manweb –

http://www.scottishpower.com/pages/connections_use_of_system_and_metering_services.asp

SSE Power Distribution

http://www.ssepd.co.uk/Library/UoS_Charges/

UK Power Networks

http://www.ukpowernetworks.co.uk/internet/en/about-us/regulatory-information/

Western Power Distribution

http://www.westernpower.co.uk/About-us/Our-system/Use-of-System-Charges.aspx

19.5.7 GDUoS (Generation Distribution Use of System) Charge

Distribution Network Operator

Based on the same principal as DUoS the GDUoS has existed for many years and until the introduction of time zones it existed as a charge against the generator, to pay for the use of the network if they were using it to export and sell electricity. It is not based on the gross output of the generator but the net volume that is exported and data collected via the settlement meter.

With the introductions of the CDCM in 2010 the GDUoS Negative charges (credits) are applied when the additional exported power has a positive effect on the distribution of electricity via the local grid. The charging methodology also has the same time of day bandings as outlined in the DUoS avoidance in the previous section,

GDUOs prices are calculated each year by the local DNO and suppliers are notified of any charges and credits. These are then passed through to a generator as per their agreement. The most recent DUoS and GDUoS rates can be viewed via the DCUSA (Distribution Connection and Use of System Agreement) web site.

http://www.dcusa.co.uk/Public/Default.aspx.

The most recent rates were published in May 2014 and based upon variable including location and time the charges range from zero to a credit of £91.09 per MWh. At this level it is still unlikely that many generators will not find this a sufficient level of incentive to operate their assets commercially for the majority of time and locations. This could potentially alter in the future as the magnitude of incentives increases the combined impact of DUoS avoidance, GDUoS, ToU avoidance and Cash Out Tariffs.

19.5.8 PPA - Power Purchase Agreement

A PPA is generally sought by any site with energy export capability in order that any electricity that is not used on site while operating generation is accounted for and that a payment is received for its use by others. While it will be physically used in real time by the next closest source of demand to the point of export, the accounting reconciliation is carried out afterwards once meter data is collected.

Typically the PPA will be based on one of two payment models to establish the price of the electricity being sold.

- Fixed Price Tariff - The self-descriptive title reflects the nature of the arrangement. It is probably more attractive to either a site that has little control over the time of export, exports at times of lower value or requires increased certainty over the value of the power. It is therefore more attractive to renewables, but it will tend to reflect the value of the power at the very low end of the value that electricity trades at in real time.
- Cash-out Tariff - rather than securing a fixed price in advance, using a ‘cash-out’ agreement will fix a percentage of the electricity in relation to its closing value for the balancing market. The System Sell Price (SSP) and the System Buy Price (SBP) are the ‘cash-out’ prices or ‘imbalance prices’ that are used to settle the difference between contracted generation or consumption and the amount that was actually generated or consumed in each of the 48 half hour trading periods per day.

A tariff of this type is preferential for a site that believes its export will on the whole be during periods where the average price will be greater than a fixed contract unit value. This is most likely when the site is engaged in programmes where the site will generate at times of capacity shortage or constraint that will be reflected in increased commodity pricing.

Combined with the DUoS and GDUoS charging methodologies that are applied on a ToU basis by the Distribution Network operators, there can be a very significant variance between fixed price and cash-out tariffs at different times of day.

19.6 DSR – Carbon and the environment

A great deal of debate and inconsistency has circulated regarding the impact of DSR on the environment, specifically in relation to CO^2 emissions. Much of this has been based on a limited set of assumptions, which are often incorrect, largely in respect of DSR offered by distributed generation. This is understandable, as the subject matter is highly complex and it is critical to encompass as many impacts, both at a local and SO level. It is necessary to understand the impact of distributed generation versus large centralised generation plants.

To establish the true impact of DSR on the environment, in particular CO^2, there several aspects that are recommended to be incorporated into any calculation.

Not all DSR programmes will have the same impact and in order to understand this it is important to consider their individual purposes as explained in Section 19.4 'Existing Programmes'.

From the perspective of generators and suppliers, DSR facilitates the integration of intermittent renewables and diminishes the need to run thermal plants at inefficient levels in order to maintain acceptable levels of dispatchable capacity in the event that they are required. This improves capacity factors of existing plant and reduces the need for new capacity, which is in itself a very difficult impact to quantify. However in a report in 2013, National Grid did offer a response to critics in respect of the 'claimed benefits' with a report that attempts quantify and justify the positive assertions.

http://www.scottish.parliament.uk/S4_EconomyEnergyandTourismCommittee/NATIONAL_GRID.pdf

Further, DSR could be used to curtail the system's generation margin, which ensures that generation capacity is greater than demand at virtually all times, by using DSR to prevent steep peaks. Rather than having installed generation for all potential and highly infrequent shortages, some of these can be addressed by DSR, which makes the system more efficient. From a supplier's perspective, DSR could moderate the price volatility in wholesale electricity markets significantly, as demand reduction could cap prices once capacity shortage occurs and prices start to rise steeply.

In the US, it has been estimated that $3bn could be saved annually by realising the market potential of DSR to reduce demand peaks, taking technical, economic and acceptance constraints into account. In the EU, a 2008 study by Cap Gemini found that a high

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penetration of DSR in the EU-15 could lead to annual energy savings of up to 202TWh, annual CO^2 emission reductions of up to 100 million tons, avoided investment of up to €50bn and annual savings in electricity bills for customers of up to €25bn by 2020.

http://www.capgemini.com/resources/demand_response_a_decisive_breakthrough_for_europe

For DNOs, DSR can facilitate the integration of distributed generation into existing distribution network infrastructure, reduce congestion in substations and enable deferring investment. The potential deferral of distribution network investment is potentially the key benefit for DNOs. Postponing investment to a time when DNOs will have gained better understanding of the new distribution infrastructure requirements in the context of new loads and increased embedded generation will reduce the risk of stranded assets. Many previous reports have stated that DSR will become important in managing the distribution networks and maintaining their reliability.

In the aim to decarbonise the electricity system, DSR constitutes a source of carbonless or lower carbon balancing services for the System Operator. DSR can replace the need to operate large thermal plant which is inefficiently part-loaded, i.e. spinning reserve to retain capacity for the delivery of balancing services, which reduces the large thermal plant's efficiency by 10-20%, thereby increasing relative CO^2 emissions and costs. A widely circulated report by IPA Energy + Water Economics highlights that delivering balancing services with DSR, even with flexible embedded generation, grants CO^2 emission reductions compared to spinning reserve. Carbon benefits occur as embedded generation is only run when actually needed. No carbon is emitted in availability mode, however, for available spinning reserve more efficient plant has to be part-loaded regularly, thereby emitting more carbon. Hence, running diesel-fired embedded generation for the infrequent times the balancing service is actually utilised leads to lower total emissions. IPA Energy + Water Economics estimated the carbon benefits of DSR replacing spinning reserve to be in the order of 300-700 tonnes CO^2 per MW/year:

www.ipaenergy.co.uk/publications/69441kel0003460000.pdf

Other reports over recent years also further identify the following benefits of DSR for the SO:

1. DSR facilitates the integration of wind generation, as it provides additional short-term flexibility and reduces the need to constrain wind generation. Where Footroom capability is developed, demand can be increased when high wind intersects with low demand.
2. The use of DSR in specific locations can also yield benefits of relieving grid congestion and location-specific transmission constraints, which enhances system reliability and can reduce the need for transmission network upgrades.
3. DSR improves operational flexibility and efficiency by providing the SO with an additional tool to manage the system.
4. Finally, DSR participation in balancing markets increases competition, which potentially reduces cost, mitigates gaming or use of market power and generally improves market efficiency.

The above mentioned benefits to SO, DNOs, generators and suppliers have the potential to reduce the costs to the customer, aid the decarbonisation of the electricity system and facilitate system reliability. Although, due to the extensive variables with provision of DSR and cost to run the system, specific values are difficult to detail.

Project FALCON aims to quantify the specific benefits that are likely to be realised in relation to local impact and consider factors such as:

- Reduced distribution losses;
- Improved operational efficiency of the network; and
- Deferment or avoidance of capital works.

The research analysis proposed within Project FALCON will not extend to the multiple benefits that may be incurred from multiple benefits that potentially occur to suppliers, The SO or Transmission Network Operator, (TNO) as a result of complimentary effects at time of dispatch.

19.7 Low Carbon Network Funded DSR trials

A recent development within the UK energy sector has been that the energy regulator, Ofgem, (Office of Gas and Electricity Markets) has made changes to the structure of the framework and incentive criteria by which DNOs are funded.

Over the next decade, DNOs face an unprecedented challenge of securing significant investment to maintain a reliable and secure network.

Ofgem, as the regulator, must ensure that DNOs deliver this at a fair price for consumers. To help achieve this, they developed a new performance based model for setting the network companies' price controls which will last eight years. The model is called RIIO: Revenue=Incentives+Innovation+Outputs.

RIIO is designed to encourage network companies to put stakeholders and customers at the heart of their decision making process, invest efficiently to ensure continued safe and reliable services and innovate to reduce network costs for current and future consumers. DNOs will need to play a full role in delivering a low carbon economy and wider environmental objectives.

As part of the transition to the new RIIO-ED1 price control Ofgem created the Low Carbon Network Fund. The LCN Fund allows up to £500m to support projects sponsored by the DNOs to trial new technology, operating and commercial arrangements. The aim of the fund is to help all DNOs understand how they can provide security of supply at value for money as Britain moves to a low carbon economy.

There are three tiers of funding under the LCN Fund. The first tier allows DNOs to recover a proportion of expenditure incurred on small scale projects. Under the second tier of the LCN Fund, an annual competition for an allocation of up to £64 million to help fund a small number of flagship projects is held. The third tier is the discretionary reward mechanism, by which DNO's can apply for a reward at the end of the project. The amount that can be applied for is capped at the amount the DNO contributed towards the project.

In LCNF projects, DNOs explore how networks can facilitate the take up of low carbon and energy saving initiatives such as electric vehicles, heat pumps, micro and local generation and demand side management. They also investigate the opportunities that smart meter roll out provide to network companies. As such, the LCN Fund should provide valuable learning for the wider energy industry and other parties. The LCN Fund is replaced at the end of the transitional period by the Network Innovation Allowance, NIA. The NIA is a set allowance each RIIO network licensee receives as part of their price control allowance to limited funding to RIIO network licensees. Its purpose is to fund smaller technical, commercial, or operational projects directly related to the licensees network that have the potential to deliver financial benefits to the licensee and its customers

There are other funding mechanisms available for Smart Grid initiatives through European programmes, research councils and organisations such as the Technology Strategy Board. These, however, are not typically used for the development of DSR services.

As the LCN Fund and IFI (Innovation Funding Incentive) have been the primary mechanism by which DSR programmes have been investigated by DNOs, a list of some the current trials is provided in the remainder of section 7.1. A full list is available via the Energy Network Association, Smart Networks Portal

http://www.smarternetworks.org/Index.aspx?Site=ed

Many of these are unlikely to be adopted as business as usual propositions without significant commercial and technical development. As part of the LCN Funding governance, the DNOs are obliged to share the learning and experience of their trials with the industry that will result in 'best practice' developments and changes to the codes under which they are regulated. One such development, directly relating to DSR is a working group that reports to Energy Network Futures Group, ENFG, and includes the SO and all DNOs. It was recognised that the current markets and commercial frameworks would act as a barrier to create unnecessary competition in the marketplace that would ultimately be borne by consumers. As a result there was a clear objective to create a shared services model to allow multiple programme operators to have access to a DSR participant rather than the current restrictions resulting from their exclusive arrangements. Further information on the scope and expected outcomes from this group are provided in Section 18

Some aspects of research from preceding LCNF trials have assisted the scope creation for FALCON's commercial trials and duplication of already established factors have been avoided. Also, through publication of the FALCON learning outputs, it is hoped that a far greater value will be achieved across the industry by the research than just satisfying the core requirement of providing real results data to the SIM.

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19.7.1 WPD – Tier1 LCNF Trial – Seasonal Generation Deployment

http://www.smarternetworks.org/Project.aspx?ProjectID=374

Reference:

WPDT1005

Starts - Ends:

01/2011 - 04/2013

Estimated Expenditure:

£300,000

Introduction:

Future energy scenarios clearly show that peak demand on the distribution network is set to increase. This project will explore a solution to reduce the impact on the existing network from such peaks. It will test the technical aspects associated with controllable demand and automated generation, and development of innovative commercial arrangements for generation availability and operation. The project will deliver new learning on the cost effectiveness of such arrangements. The project will consist of two phases:

Phase 1 will involve the installation of a single point of generation at an 11kV substation site. The key objective of this phase will be to initiate, develop and deploy the engineering interface, commercial arrangement and first stage generation control methodology.

Phase 2 will utilise existing network connected generation along with strategically placed generation connected to an adjacent section of 11kV network, which will be a test within a more complex network environment. This will provide a platform for commercial arrangements and control methodologies to be further developed.

Project objectives were as follows:

- Develop and deploy an automated network generation control system
- Provide network support through the integration of an automated demand triggered generation system
- Develop and deploy an availability and commercial operating arrangement - DNO to DSO
- Provide a commercial arrangement similar to the Short Term Operating Reserve (STOR) arrangements between aggregators and NG, but specifically tailored to reflect the needs of the local grid rather than GB system balancing
- Increase network flexibility and security through the use of robust generation
- Ensure that the engineering model and commercial framework are aligned in order to provide maximum benefit for existing assets and end user customers
- Assess the benefit from capital deferment, by complimenting existing network assets with strategic generation thus maximising asset life.

Expected Benefits:

- Ability to use temporary seasonal Distributed Generation (DG) to lop peaks - reliability, contribution to design standards, etc.
- Suitability of contracting existing DG to avoid peaks - reliability, contribution to design standards, etc.
- Develop a local market mechanism
- Identify customer appetite for participating in such a scheme
- Assess business case
- Identify regulatory/other barriers
- Explore interaction with STOR and other market mechanisms.

19.7.2 Thames Valley Vision - Scottish and Southern Energy Power Distribution

http://www.thamesvalleyvision.co.uk/

Reference:

SSET203

Starts - Ends:

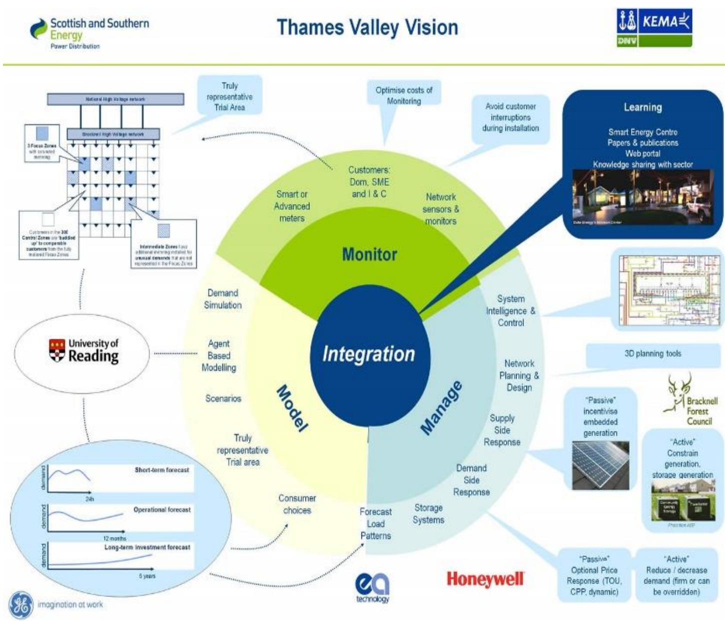
01/2012 - 03/2017

Estimated Expenditure

£27,230,000

Introduction:

Thames Valley Vision (TVV) will revolutionise the way in which DNOs utilise their existing networks. This project is a complete solution that will allow us to anticipate, understand and support behaviour change in individuals, small businesses and larger companies to help us manage our networks more effectively as GB moves towards a low carbon economy. Building on the techniques developed for supermarket loyalty schemes, TVV will use data intelligently to identify and predict network stress points in the short, medium and long term in order that DNOs can make more informed decisions.



TVV proposes that a better understanding of and more active role for electricity consumers can minimise the investment required to maintain secure distribution networks that meet customer needs.

Objectives:

The project will evaluate solutions including:

- A new network and planning environment
- Industrial and Commercial and Small and Medium sized Enterprises (SMEs) automated demand side response
- Low Voltage (LV) static voltage control
- Street level energy storage
- A range of communications solutions
- Additionally the project will incorporate learning from other projects from GB and worldwide.

TVV will deliver new commercial agreements, procedures, policies and will inform national standards. It will disseminate learning through targeted communication and our low carbon community advisory centre. Ultimately, TVV will enable DNOs to avoid £5bn of network reinforcement through the involvement of all customers groups and a comprehensive understanding of networks.

Expected Benefits:

Scottish and Southern Energy Power Distribution are confident that TVV will provide a range of benefits for DNOs as energy is decarbonised.

Further to this is anticipated that TVV will yield more immediate benefits including:

- Accelerated low carbon technology connection for customer
- Avoidance of supply failure resulting from unanticipated demand peaks
- Reduction of network losses as a result of power factor correction
- Informed business plans going into RIIO-ED1 with the ability to model scenarios
- Customer groups with an improved understanding of how to self-mitigate network issues through the way in which they select and implement low carbon solutions
- Evaluation of resource and skill requirements
- Training and learning dissemination
- Enhanced data to inform DPCR5 output measures
- A range of specific innovative alternatives to reinforcement
- A no Customer Minutes Lost (CML) impact implementation strategy
- Enduring productive relationships with stakeholder.

19.7.3 SoLa Bristol – Western Power Distribution

http://www.smarternetworks.org/Project.aspx?ProjectID=394

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Starts - Ends: 12/2011 - 01/2015

Estimated Expenditure: £2,484,000

Introduction:

GBs transition to a low carbon economy will require significant changes to the way we supply and use energy. Electrification of transportation and heating, combined with dense deployments of PV panels, will give rise to additional constraints on electricity networks, particularly at Low Voltage (LV). These constraints cannot be ignored, and will ultimately adversely affect the customer and their own low carbon aspirations. To address this, networks can be strengthened using conventional reinforcement or by developing novel approaches.

The SoLa Bristol project is an innovative combination of energy storage in customers premises, coupled with new variable tariffs and integrated network control to overcome generation or load related constraints at key times of the day. It will explore the use of Direct Current (DC) power in customer premises in conjunction with battery storage shared virtually between the DNO and customer, providing benefits to both parties. Through batteries, the LV network will be operated more actively with additional capacity to manage peak load, control voltage rise and reduce system harmonics.

The techniques trialled will, through reduction in constraints and need for network reinforcement, facilitate the connection of low carbon devices at reduced cost at over 40 locations in a range of premise types including homes, schools and a business.

Objectives:

The project will test the following Hypotheses:

- Should new Low Carbon Technologies (LCTs) increase distribution network peaks and cause thermal overloads, then battery storage, demand response and DC networks could be an efficient solution, conventional network reinforcement for short thermal overloads may not the most efficient use of customers money
- If DC networks in properties could be used to reduce network harmonics, phase distortion and improve voltage control then their use may be vital in the connection of LCTs. Because the safe, efficient operation of distribution networks is reliant on the power quality and voltage being within statutory limits
- If DNOs and customers could share battery storage on DC networks with a variable tariff, then the mutual benefits may make battery storage financially viable, as battery storage could be a shared asset or sold to customers as a service.

Expected Benefits:

Western Power Distribution have identified four areas where customers could benefit from the proposed solution:

- Keeping the lights on, through the installation of the BRISTOL system, the batteries will be used to provide enhanced resilience during power outages. Lighting, computing, telecommunications and potentially central heating pumps will be available from the battery storage even during network power outages
- Lower energy bills through a better control of energy; a variable tariff rewarding customers for reducing their peak energy demand, passing on the cost savings. Clearer, more transparent energy bills through the LV connection manager using energy efficiency, better use of PV
- Improved energy efficiency: Supplying DC equipment using a high quality AC/DC converter and PV panels powering the DC network instead of a large number of inefficient AC/DC converters will reduce electricity losses
- Quicker and cheaper connections: Conventional network reinforcement can not only be costly, but also require significant scheduling; the BRISTOL solution is one that could be implemented much faster and cost effectively.
- There are nine areas where DNOs could benefit from learning as a result of the BRISTOL project:
- The project will develop a tool that could rapidly be deployed by DNOs to reduce network hotspots created by the connection LCTs
- The project will test the benefits of storage located at customer premises, rather than at substations, providing the additional LV feeder load and voltage control support
- By oversizing the battery in the customers premises, the project will explore the business case for DNOs operating a virtual partition of distributed storage
- BRISTOL will test how batteries can be used with demand response by customers to take advantages of variable retail tariffs. From this DNOs will gain an insight into the residual impact of LCTs on the distribution networks
- The project will provide insight into how customers perceive innovative solutions such as the BRISTOL solution
- BRISTOL will create an intelligent self-managing network linking together the substation with multiple properties with battery storage and demand response to reduce voltage rise and reduced peak demand
- This project will use intermittent generation and battery storage when making network planning assumptions for the connection of other customers
- BRISTOL will explore lower harmonic distortions on the network voltage by solving the problem, reducing power quality issues
- The Project will provide better use of the existing distribution assets.

19.7.4 Capacity to Customers – Electricity North West Limited

http://www.enwl.co.uk/c2c

Reference: ENWLT203

Starts - Ends: 01/2012 - 12/2014

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Estimated Expenditure: £9,597,000

Introduction:

Capacity to Customers (C2C) engages customers in an innovative form of demand/ generation side response that accommodates much higher demands on existing electricity networks without the need for reinforcement. Customers are at the heart of C2C and it seeks to prove that the innovative application of existing technology together with new commercial offerings can be combined to meet customers' future low carbon needs at much lower cost. C2C's technical elements leverage techniques developed for customer service improvements to offer significantly higher capacity to customers. C2C will be piloted on High Voltage (HV) networks supplying 12% of our customers allowing them secure access to the networks' previously unavailable latent capacity.

As GB fulfils its decarbonisation obligations under the Climate Change Act 2008, to cut greenhouse gas emissions by 80% by 2050, the demand on electricity networks will dramatically increase. Various reports forecast overall electricity demand to grow by 1.2% per annum to 600TWh/year by 2050, an approximate 100% increase from current levels. This increase in network demand will be driven primarily through the decarbonisation of heat, transportation and electricity production rather than by a growing population. The Problem has two direct consequences which will need to be resolved in order to move the UK towards a decarbonised economy:

- High costs to customers
- Significant environmental and societal impacts.
- The techniques that traditional reinforcement use are also very intrusive for local communities and can often involve extensive excavations and disruption. Average reinforcement timescales are in the region of 12-16 weeks for work involving cable upgrades or switchgear and much longer when involving new transformers or more complicated work.

Objectives:

- The key objectives of the C2C project are as follows:
- Adaptive network control functionality: The trial will develop advanced network control functionality that will through productisation be available to all GB DNOs
- Demand response commercial templates: The trial will produce a series of model commercial contracts that can be used by all DNOs to extend the C2C Method and its benefits to all DNO customers
- Customer segmentation template: The trial will produce a customer segmentation template, describing how a DNO's customer base can be segmented and hence better approached for the introduction of demand response contracts
- New connections process: The trial will produce a new connections process detailing those technical and commercial steps required to extend the benefits to future C2C customers

- Overall customer feedback: This includes feedback from customers participating in the C2C Project including; comments on connections process, the form of response and feedback from customer engagement on planned interruptions and unplanned interruptions
- Network data: Detailed analysis of the benefits of the C2C Method on network losses and power quality in the form of a full set of network performance data
- Modelling/Simulation outcomes: The simulations will provide a detailed technical and economic assessment of the benefits of the C2C Solution
- New design and planning standard: The Method represents a fundamental change in the evolution of grids from passive to active operation and Electricity North West Ltd in conjunction with Parsons Brinckerhoff Power will produce proposals regarding new operating and design standards to inform the amendment or replacement of Engineering Recommendation P2/6.

Expected Benefits:

The principal benefit to customers of the C2C Solution is that it enables significant additional network load and generation to be connected, without incurring the high levels of expenditure associated with traditional HV and EHV network reinforcement. Electricity North West Ltd.'s analysis shows that if the technical and commercial elements of the C2C Solution were adopted across the Electricity North West Ltd network, then it would release 2.4 GW of existing capacity on the HV networks, without reinforcement. This is around 35% of the existing firm HV network capacity or around 50% of simultaneous HV demand. Analysis of electrical energy scenarios to 2050 suggests the C2C Method could thus replace much of the traditional HV reinforcement activity in the period to 2035; however this is viewed as a conservative estimate and could indeed defer reinforcement in certain networks to 2050.

Electricity North West Ltd has undertaken initial modelling work on the potential benefits of its C2C Project. This modelling has been based on assessing a sample of real customer connection applications and general reinforcement projects, and the associated network reinforcement expenditure. Electricity North West Ltd and Parsons Brinckerhoff Power have examined these case studies to determine both the viability of the proposed C2C Solution and to assess their value to customers. Under the C2C Project Electricity North West Ltd will more accurately quantify the benefits arising from the Method, enabling Ofgem and network operators to examine future incentive arrangements and allowance mechanisms within the new RIIO (Revenue, Incentive, Innovation and Output) price control.

The C2C Solution negates the need for much of the engineering works associated with reinforcement, by better utilising the installed network capacity.

19.7.5 Low Carbon London – UK Power Networks

http://innovation.ukpowernetworks.co.uk/innovation/en/Projects/tier-2-projects/Low-Carbon-London-(LCL)/

Reference: EDFT2001

Starts - Ends: 01/2011 - 06/2014

Estimated Expenditure: £36,060,000

Introduction:

Low Carbon London is a pioneering learning programme. Its aim is to use London as a test bed to develop a smarter electricity network that can manage the demands of a low carbon economy and deliver reliable, affordable zero carbon electricity to businesses, residents and communities.

London has a unique opportunity to be at the heart of this drive towards a low carbon economy. Currently it has the highest levels of carbon emissions in the UK, one of the most utilised electricity networks in the country and a very tough carbon reduction target of 60% on 1990 levels by 2025.

To cut its carbon emissions, London is calling for a big increase in distributed and micro-generation, electric vehicles, combined cooling heating and power systems, and heat pumps. Low Carbon London is about learning how to accommodate these new demands on the electricity network, while helping customers to make the best use of national low carbon electricity production.

London's approach to carbon reduction is likely to be mirrored across UK, so the knowledge gained in London will help electricity networks across the country to prepare for a low carbon future.

Objectives:

The outlook for the project over the next reporting period, despite the various challenges, is very positive. The addition of a second energy supplier to the project provides an increased available pool of residential and potentially Small and Medium Enterprises (SMEs), commercial trial participants, whilst developing links with various industry organisations.

Low Carbon London will develop a new approach to distribution network management to meet growing demand from emerging low carbon technologies, such as electric vehicles, heat pumps and distributed generation. It will focus on carbon reduction targets and the need to reduce dependency on conventional reinforcement.

Expected Benefits:

Low Carbon London will demonstrate how to develop electricity networks that enable a low carbon world and, at the same time, offer customers informed choice about their electricity consumption.

The results of the trials will clearly indicate the potential for new approaches to network management to deliver real savings to customers as UK Power Networks move towards a low carbon economy. These approaches will be valid and meaningful for customers across Great Britain

19.7.6 Customer-Led Network Revolution– Northern Powergrid

http://innovation.ukpowernetworks.co.uk/innovation/en/Projects/tier-2-projects/Low-Carbon-London-(LCL)/

Reference: CET2001

Starts - Ends: 01/2011 - 12/2014

Estimated Expenditure: £52,620,000

Introduction:

The move to a low-carbon economy, in particular the growth in Low Carbon Technologies (LCTs), will place additional strain on electricity distribution networks. If innovative solutions are not found this will require significant extra network investment and could delay the take-up of LCTs. This will start to be a problem on pockets of network by 2015 and a wider more significant issue from 2020. Therefore knowledge gained over the next three years will be relevant to the price control RIIO ED1 period.

The network costs associated with mass uptake of LCTs could be significantly reduced, and delivery accelerated, by using a combination of:

- New network technologies
- Flexible customer response from both demand and generation.

This will only happen if new commercial arrangements between suppliers, DNOs and customers are developed.

Objectives:

The project aims to ascertain:

- What are current, emerging and possible future customer (load and generation) characteristics?
- To what extent are customers flexible in their load and generation, and what is the cost of this flexibility?
- To what extent is the network flexible and what is the cost of this flexibility?

- What is the optimum solution to resolve network constraints driven by the transition to a low carbon economy?
- What are the most effective means to deliver optimal solutions between customer, supplier and distributor?

Expected Benefits:

The solution is expected to deliver significant net benefits to customers. Northern Powergrid expect it to accelerate the take up of LCT's. In addition Northern Powergrid expect the project to optimise the use of installed network capacity and promote the use of Demand Side Response (DSR).

19.8 Stadium MK: site assessment

The following is an excerpt from the documentation exchanged with Stadium MK following a site analysis. This provided an independent assessment by SGC of the potential value of DSR participation for the site along with and explanation of the available services and work necessary to commission the site for DSR use.

Introduction

The purpose of this document is a high level analysis based upon data provided for the site(s)

- Milton Keynes Stadium & Hotel

Against potential Demand Response opportunities including;

- National Grid - STOR (Short Term Operating Reserve)
- National Grid - Frequency Response
- Triad / TNUoS avoidance (Transmission Network Use of System Charge)

If adequate value is identified from potential participation within the service opportunities listed above, we would propose that a full site analysis is commissioned for the site(s). A full survey will not only seek to establish a more accurate value and capital costs for the services, but also assessment of existing assets for their primary function. Where appropriate the report will also outline potential risks relating to broader market conditions and recommendations for further capital investment to improve operational efficiency, cost management and carbon reduction.

A brochure offering greater detail on this service should have been provided in conjunction with this document.

STOR

National Grid, as the National Electricity Transmission System Operator (NETSO) requires access to extra power in the form of either generation or demand reduction during certain periods of the day in order to ensure the ability to be able to deal with actual demand being greater than forecast demand and/or unforeseen generation unavailability. These additional sources of power are referred to as Reserve and comprise synchronised and nonsynchronised sources.

This can be accessed either by contracting directly with NETSO or via one of the UK's growing number of service aggregators.

The general principal of STOR provision is as an operational service and not as a commodity sale of electricity. National Grid bases the payment for service upon the delta shift in consumption capacity and this can be achieved either by demand reduction or increased generation. In the event that service is provided by means of generation the output power remains the property of the site and will either displace importation costs or can be sold in the event of export. As a result of this important commercial factor the site is in no way compromised in relinquishing its generator control to a third party or increasing its operational risk.

Frequency Response

National Grid has a licence obligation to control frequency within the limits specified in the 'Electricity Supply Regulations', i.e. ±1% of nominal system frequency (50.00Hz) save in abnormal or exceptional circumstances. National Grid must therefore ensure that sufficient generation and / or demand is held in automatic readiness to manage all credible circumstances that might result in frequency variations.

Frequency services can be offered to National Grid 24/7 or in conjunction with STOR, but not concurrently.

Triad

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The “triad” system is the means by which industrial and commercial electricity consumers pay for the electricity transmission network in Great Britain. The triad system doubles up as a peak load management mechanism.

Triad charges are part of Transmission Network Use of System (TNUoS) charges, which National Grid recovers every year from Licensed Generators and Licensed Electricity Suppliers.

The triad charging system has been designed to penalise consumption during peaks, especially in highly stressed parts of the network, and therefore an opportunity to reduce significant annual charges if consumption during peaks is avoided.

Operational Benefits

By participation in ‘Smart Grid’ services such as those listed it is typical that a site will also take advantage of a number of additional direct & indirect benefits. These include;

- Reduced operational burden in relation to asset monitoring and testing.
- Carbon reduction for Corporate Social Responsibility
- National support for increased adoption of renewable generation technologies
- Improved asset performance
- Reduced operational risk
- Supports ‘recommended’ emergency fuel management strategy

Asset detail

The site benefits from a single ‘stand by’ asset that provides an alternative to mains supply as critical services redundancy in the event of mains supply power failure. It is unclear at this stage as to the configuration of the switchgear and distribution panels as to the maximum concurrent running capacity of the generation and export potential. It is however a likely assumption is that operational requirements of the building would necessitate a fully synchronised mains connection with export permissions in order to render the generator viable for participation in any of the outlined commercial schemes.

Based upon analysis of the Half Hourly site consumption data it has been confirmed that there is around ***160kW*** average load capacity that could be reliably used for Smart Grid operation if a short term synchronisation permission were granted. It is unlikely that this would generate adequate income as to satisfy the investment expectations of MK DONS. Financial modelling has therefore been based upon assumption of export.

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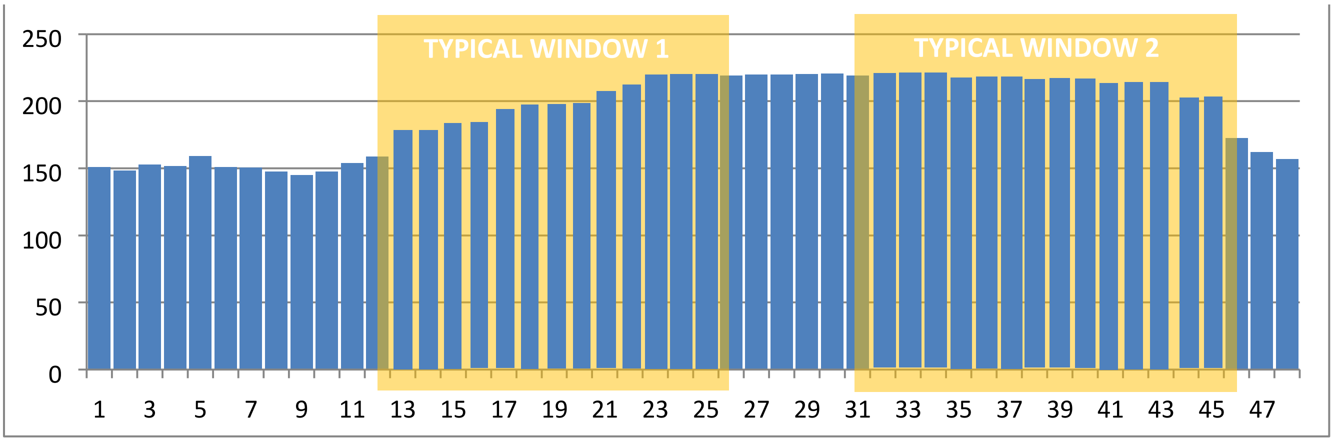

Figure 46 - STOR load evaluation

Approximate annual Financial Projection Summary (400kW)

Availability	£7,000	
Utilisation	£3,000	*Estimated 50 hours*
Triad	£7,200	*Estimated 30 hours*
Electricity Value	£2,700	
DUoS	£ 1,200	
Fuel Cost	£6,200	
Total Net Income	**£14,900**	

Assumptions

For the purposes of providing a desktop analysis a number of assumptions have been applied in order to provide an approximate financial projection. There are many variables relating to the provision of such services that will impact the associated costs to set up, contract arrangements and technical capability. The purpose of the main survey is to identify all of the potential variables and identify the most suitable strategic plan and a comprehensive technical scope / plan to deliver it.

Table of assumptions

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STOR	*Direct provision to National Grid* *Based on average market pricing (2013)*
Triad	*100% benefit resulting from full cost avoidance* *20 x 1.5 hour runs*
DUoS	*Milton Keynes – WPD Midlands*
Fuel Consumption	*270 Litres per MWh @ Cost £0.75 per litre*
Electricity	*Avoided cost £80 per MWh* *Export value £55 per MWh*
Site Load	*200kw average demand*
Generator Capacity	*400kw*

19.9 FALCON (S1) DSR Contract

Demand Response Agreement - FALCON

Between:

(1) **Western Power Distribution** (West Midlands) plc (company number: 0360057) whose registered office is at Avonbank, Feeder Road, Bristol BS2 0TB ("WPD"); and

(2) ________________________________ Limited (company number: _____________) whose registered office is at ____ ____ (the "Energy Partner").

Date of Agreement (date of signature):	
Season(s)	1st Nov 2013 – 28th Feb 2014

Date of Agreement (date of signature):	
	1st Nov 2014 – 28th Feb 2015
Availability Window	16:00 to 20:00 Monday - Friday (inclusive)
Response Time	**30** minutes
Energy Partner Authorised Person(s)	[insert name(s) of Energy Partner individual(s)]
Contact Method	[insert email address / telephone number]
Control Room Contact	Name: Gary Swandells Email: ggswandells9@westernpower.co.uk Telephone number:

Site(s)	MPAN(s)	Agreed Capacity (MW)*

*Note: Agreed Capacity is represented in the Payment Calculation in Schedule 2 as "CM".

Please note: The parties hereby acknowledge that: (a) the provision of the Services; (b) the compliance with any Instruction issued by WPD; and (c) any participation in Project FALCON by the Energy Partner and/or its subcontractors is entirely voluntary.

To the extent that the terms of this Agreement conflict with any of the rights or obligations of the parties under the Electricity Act 1989, the Utilities Act 2000, the Energy Acts 2008 – 2011, the National Terms of Connection and any other licences, codes or industry agreements related to such legislation (the **"Electricity Regulations"**), the terms of the Electricity Regulations shall prevail.

We agree to be bound by the Agreement (as defined in sub-clause 1.1 (Definitions and Interpretation) of the attached terms and conditions).

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Signed on behalf of Western Power Distribution (West Midlands) plc: Signature: ____ Name: _____ ____ Role: _ _____ ____
Signed on behalf of: ____: Signature: ____ Name: _____ ____ Role: _ _____ ____

Schedule 1

(Demand Response Procedure)

1. By 10:00am on each Friday of the Season, the Energy Partner shall notify the Control Room Contact by email of the Sites that are **unavailable** to provide Demand Response during the next Availability Window.

2. In the absence of any notification to the contrary under paragraph 1, WPD shall be entitled to assume that all Sites are **available** to provide Demand Response (**"Available Sites"**).

3. If the Energy Partner becomes aware of any changes to the availability of a Site as notified to WPD under paragraph 1, it shall update the Control Room Contact by email of such change as soon as reasonably practicable.

4. During each Availability Window:

(a) the Energy Partner shall ensure that the Contact Method is available and operational; and

(b) the Control Room Contact may issue via the Contact Method one Instruction per day per Available Site to the Energy Partner.

5. On receiving an Instruction, the Energy Partner shall within the Response Time:

(a) procure that the Demand Response is carried out at each Site in accordance with the relevant Instruction; and

(b) in the event that a Site is unable to maintain the Critical Capacity (CC) during the Response Time then the Energy Partner Authorised Person shall email the Control Room Contact to notify this.

6. The Energy Partner shall procure that the Demand Response ceases at each Site at the end of the relevant Response Period or, if earlier, as requested by the Control Room Contact .

Schedule 2

(Payment Calculation)

Generation delivery calculation

For a Site that increases generation during a Demand Response event, we calculate the delivery as:

$$D_i = \max[C_i - AvC, 0]$$

Consumption delivery calculation

For a Site that reduces consumption, the opposite formula is required:

$$D_i = \max[AvC - C_i, 0]$$

Average delivery during a Demand Response event

Given a Demand Response event with average demand figure AvC, start time ST, finish time FT, we calculate the average delivery as follows:

$$D_{avg} = \frac{\sum_{i=ST}^{FT} \min(D_i, CM)}{FT - ST + 1}$$

Total delivery and payment value

$$D = D_{avg} \times \left(\frac{FT - ST + 1}{60}\right)$$

$$Payment = D \times 300$$

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(a detailed payment calculation document with full parameter definition and graphical representation is available on request)

(Terms and Conditions)

It is agreed as follows:

1. Definitions and interpretation

1.1 In this Agreement, unless the context otherwise requires, the following words have the following meanings:

"Agreed Capacity" means the target net MW consumed or generated by a Site during the Response Period as set out on the front page of this Agreement;

"Agreement" means this agreement (including the details set out on the front page, the Terms and Conditions, and any other schedule or annexure to it) made between the parties;

"Applicable Legislation" means all Policies and laws, statutes, acts, regulations, codes, judgments, orders, directives or determinations applicable to the performance of the Services;

"Authorised Person" means the individual of the Energy Partner specified as the authorised person on the front page of this Agreement;

"Availability Window" means 16:00 to 20:00 (inclusive) on Monday to Friday (inclusive);

"Contact Method" means the contact method specified on the front page of this Agreement;

“Control Room Contact” means the individual at the WPD facility from where network is monitored and managed, who is specified as the contact on the front page of this Agreement;

"Date of Agreement" means the date specified as the date of signature on the front page of this Agreement;

“Demand Response" means the regulation of the amount of electricity consumed and/or generated by a Site to achieve the Agreed Capacity;

"Payment" means the payment calculated in accordance with Schedule 2 of this Agreement;

"Policies" means any instructions, rules or policies issued by WPD from time to time, including without limitation Policy Document: LE7 Relating to Bribery;

"Response Period" means a period of time between one to two hours during which the Demand Response is to be maintained for a Site as set out in the Instruction;

"Response Time" means the maximum period of time (in minutes) which is permitted to elapse from receipt of the Instruction by the Energy Partner and achieving the Agreed Capacity at the relevant Site(s) at set out on the front page of this Agreement**;**

"Services" means the services to be provided by the Energy Partner as set out in clause 3 and Schedule 1;

"Settlement Period" has the meaning ascribed to it in the Balancing and Settlement Code published by the National Grid Company plc;

"Site" means each of the sites set out on the front page of this Agreement;

"VAT" means value added tax chargeable under English law for the time being and any similar, additional tax.

1.2 In this Agreement, unless the context otherwise requires: (a) words in the singular include the plural and vice versa and words in one gender include any other gender; (b) a reference to a statute or statutory provision includes: (i) any subordinate legislation (as defined in Section 21(1), Interpretation Act 1978) made under it; (ii) any repealed statute or statutory provision which it re-enacts (with or without modification); and (iii) any statute or statutory provision which modifies, consolidates, re-enacts or supersedes it; (c) references to: (i) any party include its successors in title and permitted assigns; (ii) a "person" include any individual, firm, body corporate, association or partnership, government or state (whether or not having a separate legal personality); (iii) clauses and schedules are to clauses and schedules of this Agreement and references to sub-clauses and paragraphs are references to sub-clauses and paragraphs of the clause or schedule in which they appear; and (iv) the headings are for convenience only and shall not affect the interpretation of this Agreement.

2. Commencement and Duration

This Agreement shall commence on the Date of Agreement and shall continue in force until terminated by either party on one month's written notice to the other party (the **"Term"**).

3. Demand Response

3.1 The Energy Partner shall: (a) during the Season, carry out its obligations as set out in Schedule 1 in accordance with Applicable Legislation and the terms of this Agreement; and (b) during the Term, permit WPD to collect and on request shall provide to WPD, any metering data in respect of each Site.

3.2 The Energy Partner may sub-contract its obligations under Schedule 1 to any third party provided that such appointment shall not relieve the Energy Partner of any obligation under this Agreement, and the acts or omissions of any such sub-contractor shall, for the purposes of this Agreement, be deemed to be acts or omissions of the Energy Partner.

3.3 The Energy Partner may not assign, transfer, charge or otherwise encumber, declare a trust over or deal in any other manner with this Agreement or any right, benefit or interest under it.

4. Payment

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4.1 In consideration of the provision of the Services in accordance with the terms of this Agreement, WPD shall pay to the Energy Partner the Charges as set out in this clause 4.

4.2 Subject to clause 10.6, WPD's liability to the Energy Partner shall not exceed the amount of the Charges and WPD shall not be liable for any other payments incurred by the Energy Partner in the provision of the Services.

4.3 The Energy Partner shall calculate the Charges for each month in accordance with Schedule 2 and, at the end of each month, the Energy Partner shall be entitled to issue its invoice to WPD for the Charges incurred in that month.

4.4 Each invoice must: (a) contain all the following information: (i) the Site(s) where the Services have been carried out; (ii) the period to which the invoice relates; (iii) the Energy Partner's details for payment; (iv) the Payment for the period of the invoice, excluding VAT; and (v) any other information that WPD may reasonably request; and (b) be sent to: Western Power Distribution, Accounts Payable, Elliott Road, Prince Rock, Plymouth, Devon, PL4 0SD, (c) be dated the date that it is issued.

4.5 All payments shall be released by WPD by the end of the month following the month of the date of the Energy Partner's invoice. Payment by WPD shall be without prejudice to any claims or rights, which WPD may have against the Energy Partner and shall not constitute any admission by WPD as to the performance by the Energy Partner of its obligations under this Agreement. Prior to making any such payment, WPD shall be entitled to make deductions or deferments in respect of any disputes or claims whatsoever with or against the Energy Partner.

4.6 All sums payable under this Agreement shall be exclusive of VAT. WPD shall pay an amount equal to such VAT to the Energy Partner in addition to any sum or consideration on receipt of a valid VAT invoice from the Energy Partner.

4.7 If WPD fails to pay to the Energy Partner any undisputed amount payable by it under this Agreement, the Energy Partner may charge WPD interest on the overdue amount from the due date up to the date of actual payment at the rate of 2% per annum above the base rate of the Bank of England. Such interest shall accrue from day to day and shall be compounded annually.

4.8 WPD may, without limiting any other rights or remedies it may have, withhold or set off any amounts owed to it by the Energy Partner against any amounts payable by WPD to the Energy Partner under this Agreement.

5. Confidentiality

Except with the consent of the disclosing party or as required by law, a court order or by any relevant regulatory or government authority or to the extent that information has come into the public domain through no fault of the receiving party, each party shall treat as strictly confidential all commercial and technical information relating to the other party received or obtained as a result of entering into or performing this Agreement including but not limited to information which relates to the provisions or subject matter of this Agreement, to any other party or to the negotiations of this Agreement.

6. Anti-Bribery

The Energy Partner shall not engage in any activity, practice or conduct which would constitute an offence under the Bribery Act 2010 and shall promptly report to WPD any request or demand for any undue financial or other advantage of any kind received or offered by the Energy Partner in connection with this Agreement.

7. Force Majeure

Neither party shall be deemed to be in breach of this Agreement, or otherwise be liable to the other, by reason of any delay in performance or non-performance of any of its obligations under this Agreement to the extent that such delay or non-performance is due to an event beyond the reasonable control of that party.

8. Termination

8.1 Either party may by notice in writing immediately terminate this Agreement, if the other party commits a material breach of this Agreement which in the case of a breach capable of remedy shall not have been remedied within 30 days of the receipt of a notice identifying the breach and requiring its remedy.

8.2 All rights and obligations of the parties shall cease to have effect immediately on termination of this Agreement except that termination shall not affect: (a) the accrued rights and obligations of the parties at the date of termination; (b) the continued existence and the validity of the rights and obligations of the parties under clause 5; and (c) any provisions of this Agreement necessary for the interpretation or enforcement of this Agreement.

9. Dispute Resolution

9.1 Subject to sub-clause 9.3, if a dispute arises out of or in connection with this Agreement, the parties shall: (a) within 30 days of written notice of the dispute being received by the receiving party in good faith seek to resolve the dispute through negotiations between the parties' senior representatives who have the authority to settle it; and (b) not pursue any other remedies available to them until at least 30 days after the first written notification of the dispute.

9.2 The appointed representatives shall use reasonable endeavours to resolve the dispute. If the dispute is not resolved in accordance with this clause, either party may propose to the other in writing that the matter be referred to a non-binding mediation. If the parties are unable to agree on a mediator either party may apply to the Centre for Dispute Resolution (CEDR) to appoint one.

9.3 Nothing in this clause shall prevent any party from having recourse to a court of competent jurisdiction for the sole purpose of seeking a preliminary injunction or such other provisional judicial relief as it considers necessary to avoid irreparable damage.

10. General

10.1 This Agreement (and any appendices attached to it) sets out the entire agreement and understanding between the parties and supersedes all prior agreements, understandings or arrangements (whether oral or written) in respect of the subject matter of this Agreement.

10.2 To the extent that any provision of this Agreement is found by any court or competent authority to be invalid, unlawful or unenforceable in any jurisdiction, that provision shall be deemed not to be a part of this Agreement, it shall not affect the enforceability of the remainder of this Agreement nor shall it affect the validity, lawfulness or enforceability of that provision in any other jurisdiction.

10.3 The rights, powers and remedies conferred on either party by this Agreement and the remedies available to either party are cumulative and are additional to any right, power or remedy which it may have under general law or otherwise.

10.4 Either party may, in whole or in part, release, compound, compromise, waive, or postpone, in its absolute discretion, any liability owed to it or right granted to it in this Agreement by the other party without in any way prejudicing or affecting its rights in respect of that or any other liability or right not so released, compounded, compromised, waived or postponed.

10.5 The Energy Partner acknowledges that it has entered into this Agreement in reliance only upon the representations, warranties, conditions and promises specifically contained or incorporated in this Agreement and, subject to clause 10.6, WPD shall have no liability to the Energy Partner in respect of any other representation, warranty, condition or promise made prior to the date of this Agreement, unless it was made fraudulently, or implied into this Agreement.

10.6 Nothing in this Agreement shall limit or exclude either party's liability for death or personal injury caused by its negligence, or the negligence of its employees, agents or subcontractors; its fraud or fraudulent misrepresentation; and any other liability which cannot by law be excluded or limited.

10.7 No single or partial exercise, or failure or delay in exercising any right, power or remedy by either party shall constitute a waiver by that party of, or impair or preclude any further exercise of, that or any right, power or remedy arising under this Agreement or otherwise.

10.8 No announcement concerning the terms of this Agreement shall be made by or on behalf of either party without the prior written consent of the other, such consent not to be unreasonably withheld or delayed.

10.9 Nothing in this Agreement or in any document referred to in it or in any arrangement contemplated by it shall create a partnership or joint venture between the parties or render a party the agent of the other, nor shall a party hold itself out as such (whether by an oral or written representation or by any other conduct) and neither party shall enter into or have authority to enter into any engagement, or make any representation or warranty on behalf of, or pledge the credit of, or otherwise bind or oblige the other party.

10.10 This Agreement may be executed in any number of counterparts and by the parties on separate counterparts, but shall not be effective until each party has executed at least one counterpart. Each counterpart, when executed, shall be an original of this Agreement and all counterparts shall together constitute one instrument.

10.11 Any notice to either party under this Agreement shall be in writing signed by or on behalf of the party giving it and shall, unless delivered to the party personally, be left at, or sent by prepaid first class post or prepaid recorded delivery to the address of the party as set out on the front page of this Agreement or as otherwise notified in writing from time to time. A notice shall be deemed to have been served at the time of delivery, if delivered personally, or 48 hours after posting.

10.12 No term of this Agreement is enforceable pursuant to the Contracts (Rights of Third Parties) Act 1999 by any person who is not a party to it.

10.13 This Agreement and any dispute, claim or obligation (whether contractual or non-contractual) arising out of or in connection with it, its subject matter or formation shall be governed by the laws of England and Wales.

10.14 Subject to clause 9, the parties irrevocably agree that the courts of England and Wales shall have exclusive jurisdiction to settle any dispute or claim (whether contractual or non-contractual) arising out of or in connection with this Agreement, its subject matter or formation.

This Agreement has been signed on the date stated as the "Date of Agreement" on the front page of this Agreement

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19.10 FALCON (S2) DSR Contract

1 Demand Response Agreement - FALCON

Between:

(1) Western Power Distribution (West Midlands) plc (company number: 0360057) whose registered office is at Avonbank, Feeder Road, Bristol BS2 0TB (**"WPD"**); and

(2) ___________________________________ Limited (company number: ______________) whose registered office is at ____ ____ (the "Energy Partner").

Date of Agreement (date of signature):	
Season	1 November 2014 to 28 February 2015
Payment Rate **(per MWh)**	[£300] Generation or [£600] Load Reduction
Energy Partner Authorised Person(s)	
Contact Method	Telephone number:
Control Room Contact	Name: Gary Swandells Email: ggswandells9@westernpower.co.uk Telephone number: 07727060075

Site(s)	**MPAN(s)**	**Desired Delta**	**Generation (G) or Reduction (R)**	**Consumption Target (MW)**
Sample DG Site	1234567891011	700kW	G	130kW Export
Sample LR Site	1234567891012	200kW	R	16kW Import

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Please note: The parties hereby acknowledge that: (a) the provision of the Services; (b) the compliance with any DR Schedule issued by WPD; and (c) any participation in Project FALCON by the Energy Partner and/or its sub-contractors is entirely voluntary.

To the extent that the terms of this Agreement conflict with any of the rights or obligations of the parties under the Electricity Act 1989, the Utilities Act 2000, the Energy Acts 2008 – 2011, the National Terms of Connection and any other licences, codes or industry agreements related to such legislation (the **"Electricity Regulations"**), the terms of the Electricity Regulations shall prevail.

Please refer to the “Participant Operation Information” document which accompanies this Agreement for more information about the FALCON Commercial Trials, and in particular for more detail relating to the Services and the calculation of the Charges. The document is provided for information only and this Agreement shall prevail in respect of any inconsistency or conflict.

We agree to be bound by the Agreement (as defined in sub-clause 1.1 (Definitions and Interpretation) of the attached terms and conditions).

Signed on behalf of Western Power Distribution (West Midlands) plc:

Signature: ____

Name: _____Roger Hey ____

Role: _ _____Future Networks Manager ______________________________________

Signed on behalf of: *Signature*: ____ *Name*: _____ ____ *Role*: _ _____ ____

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Schedule 1

(Demand Response Procedure)

1. The Season consists of 17 weeks from 1 November 2014 to 28 February 2014 (inclusive). Demand Response may be carried out between 16:00 to 20:00 (inclusive) on Monday to Friday (inclusive) in each week of the Season.

2. By 17:00 on each Monday of the Season, the Control Room Contact shall provide the DR Schedule to the Energy Partner ("you") for each Site for the following week via the Contact Method, which you must acknowledge receipt of to the Control Room Contact by 12:00 on the following day (Tuesday).

3. The DR Schedule will set out when each Response Period is to start and finish for each day of the week. A Response Period is the exact period during which the Consumption Target is to be maintained: it will not be less than 1 hour or more than 2 hours, but there may be some days when there is no Response Period at all. The Consumption Target for each Site is set out on the front page of this Agreement.

4. If you become aware of any circumstances which may affect the ability of a Site to meet the requirements of the DR Schedule, you must notify the Control Room Contact in advance by email as soon as reasonably practicable.

5. During each Response Period, you must procure that:

(a) the Demand Response is carried out at each Site in accordance with the DR Schedule for that week;

(b) the Demand Response ceases at each Site at the end of the Response Period or, if earlier, as requested by the Control Room Contact; and

(c) the Control Room Contact is notified by telephone if a Site is unable to carry out the Demand Response.

6. The ability of each Site to maintain the Consumption Target during each Response Period will be measured in one minute intervals. The Payment Rate will be calculated on a pro-rated basis for each minute during a Response Period as follows:

(a) For each minute that a Site maintains greater than or equal to 90% of the Desired Delta during a Response Period, 100% of the Payment Rate is due in respect of that Site up to the amount of the Consumption Target. No additional payment is due for exceeding the Consumption Target; and

(b) For each minute that a Site achieves less than 90% of the Desired Delta during a Response Period, the Payment Rate shall be reduced by 2% for each 1% that the Site achieved less than the Consumption Target, so that 0% of the Payment Rate would be due if 50% (or less) of the Consumption Target was achieved. (Terms and Conditions)

It is agreed as follows:

1. Definitions and interpretation

1.1 In this Agreement, unless the context otherwise requires, the following words have the following meanings:

"Agreement" means this agreement (including the details set out on the front page, the Terms and Conditions, and any other schedule or annexure to it) made between the parties;

"Applicable Legislation" means all Policies and laws, statutes, acts, regulations, codes, judgments, orders, directives or determinations applicable to the performance of the Services;

"Charges" means the payment calculated in accordance with the Schedule to this Agreement;

"Consumption Target" means the target net MW consumed or generated by a Site during the Response Period as set out on the front page of this Agreement

"Contact Method" means the contact method specified on the front page of this Agreement;

“Control Room Contact” means the individual at the WPD facility from where network is monitored and managed, who is specified as the contact on the front page of this Agreement;

"Date of Agreement" means the date specified as the date of signature on the front page of this Agreement;

“Demand Response" means the regulation of the amount of electricity consumed and/or generated by a Site to maintain the Consumption Target in accordance with the DR Schedule;

“DR Schedule” means the time periods for each Site when the Demand Response is to be carried out, as notified and updated by WPD each week during the Season;

"Policies" means any instructions, rules or policies issued by WPD from time to time, including without limitation Policy Document: LE7 Relating to Bribery;

"Response Period" means a period of time between one to two hours during which the Demand Response is to be maintained for a Site as set out in the DR Schedule;

“Season” means the term of this Agreement as set out on the front page of this Agreement;

"Services" means the services to be provided by the Energy Partner as set out in clause 3 and the Schedule to this Agreement;

"Site" means each of the sites set out on the front page of this Agreement;

"VAT" means value added tax chargeable under English law for the time being and any similar, additional tax.

1.2 In this Agreement, unless the context otherwise requires: (a) words in the singular include the plural and vice versa and words in one gender include any other gender; (b) a reference to a statute or statutory provision includes: (i) any subordinate legislation (as defined in Section 21(1), Interpretation Act 1978) made under it; (ii) any repealed statute or statutory provision which it re-enacts (with or without modification); and (iii) any statute or statutory provision which modifies, consolidates, re-enacts or supersedes it; (c) references to: (i) any party include its successors in title and permitted assigns; (ii) a "person" include any individual, firm, body corporate, association or partnership, government or state (whether or not having a separate legal personality); (iii) clauses and schedules are to clauses and schedules of this Agreement and references to sub-clauses and paragraphs are references to sub-clauses and paragraphs of the clause or schedule in which they appear; and (iv) the headings are for convenience only and shall not affect the interpretation of this Agreement.

2. Commencement and Duration

This Agreement shall commence on the Date of Agreement and shall continue in force for the term of the Season, unless terminated earlier in accordance with its terms.

3. Demand Response

3.1 The Energy Partner shall during the Season: (a) carry out its obligations as set out in the Schedule to this Agreement in accordance with Applicable Legislation and the terms of this Agreement; and (b) permit WPD to collect and on request shall provide to WPD, any metering data in respect of each Site.

3.2 The Energy Partner may sub-contract its obligations set out in the Schedule to this Agreement to any third party provided that such appointment shall not relieve the Energy Partner of any obligation under this Agreement, and the acts or omissions of any such sub-contractor shall, for the purposes of this Agreement, be deemed to be acts or omissions of the Energy Partner.

3.3 The Energy Partner may not assign, transfer, charge or otherwise encumber, declare a trust over or deal in any other manner with this Agreement or any right, benefit or interest under it.

3.4 Any metering equipment provided by WPD shall at all times remain the property of WPD, and neither the Energy Partner nor any of its sub-contractors shall have any right, title, or interest in or to such equipment.

3.5 The Energy Partner shall not, and shall procure that its sub-contractors (if any) shall not, sell, lease, hire, charge by way of security, modify, move, interfere with or otherwise deal with any metering equipment provided by WPD in any way, without the prior written consent of WPD.

4. Payment

4.1 In consideration of the provision of the Services in accordance with the terms of this Agreement, WPD shall pay to the Energy Partner the Charges as set out in this clause 4.

4.2 Subject to clause 10.6, WPD’s liability to the Energy Partner shall not exceed the amount of the Charges and WPD shall not be liable for any other payments incurred by the Energy Partner in the provision of the Services.

4.3 WPD shall calculate the Charges for each calendar month of the Season in accordance with the Schedule to this Agreement.

4.4 Within 28 days of the end of each calendar month of the Season, WPD shall provide a statement of the Energy Partner’s performance in providing the Services and the Charges due in respect of that month. On receipt of this statement, the Energy Partner shall be entitled to issue its invoice to WPD for the Charges incurred in that month.

4.5 Each invoice must: (a) contain all the following information: (i) the Site(s) where the Services have been carried out; (ii) the period to which the invoice relates; (iii) the Energy Partner’s details for payment; (iv) the Payment for the period of the invoice, excluding VAT; and (v) any other information that WPD may reasonably request; and (b) be sent to: Western Power Distribution, Accounts Payable, Elliott Road, Prince Rock, Plymouth, Devon, PL4 0SD, (c) be dated the date that it is issued.

4.6 All payments shall be released by WPD by the end of the month following the month of the date of the Energy Partner's invoice. Payment by WPD shall be without prejudice to any claims or rights, which WPD may have against the Energy Partner and shall not constitute any admission by WPD as to the performance by the Energy Partner of its obligations under this Agreement. Prior to making any such payment, WPD shall be entitled to make deductions or deferments in respect of any disputes or claims whatsoever with or against the Energy Partner.

4.7 All sums payable under this Agreement shall be exclusive of VAT. WPD shall pay an amount equal to such VAT to the Energy Partner in addition to any sum or consideration on receipt of a valid VAT invoice from the Energy Partner.

4.8 If WPD fails to pay to the Energy Partner any undisputed amount payable by it under this Agreement, the Energy Partner may charge WPD interest on the overdue amount from the due date up to the date of actual payment at the rate of 2% per annum above the base rate of the Bank of England. Such interest shall accrue from day to day and shall be compounded annually.

4.9 WPD may, without limiting any other rights or remedies it may have, withhold or set off any amounts owed to it by the Energy Partner against any amounts payable by WPD to the Energy Partner under this Agreement.

5. Confidentiality

5.1 Except with the consent of the disclosing party or as required by law, a court order or by any relevant regulatory or government authority or to the extent that information has come into the public domain through no fault of the receiving party, each party shall treat as strictly confidential all commercial and technical information relating to the other party received or obtained as a result of entering into or performing this Agreement including but not limited to information which relates to the provisions or subject matter of this Agreement, to any other party or to the negotiations of this Agreement.

5.2 The Energy Partner acknowledges that WPD may share any metering data and the performance of each Site under this Agreement with its contractors and project partners and may disseminate any learning arising from this arrangement with the wider electricity industry.

6. Anti-Bribery

The Energy Partner shall not engage in any activity, practice or conduct which would constitute an offence under the Bribery Act 2010 and shall promptly report to WPD any request or demand for any undue financial or other advantage of any kind received or offered by the Energy Partner in connection with this Agreement.

7. Force Majeure

Neither party shall be deemed to be in breach of this Agreement, or otherwise be liable to the other, by reason of any delay in performance or non-performance of any of its obligations under this Agreement to the extent that such delay or non-performance is due to an event beyond the reasonable control of that party.

8. Termination

8.1 Either party may by notice in writing immediately terminate this Agreement, if the other party commits a material breach of this Agreement which in the case of a breach capable of remedy shall not have been remedied within 30 days of the receipt of a notice identifying the breach and requiring its remedy.

8.2 All rights and obligations of the parties shall cease to have effect immediately on termination of this Agreement except that termination shall not affect: (a) the accrued rights and obligations of the parties at the date of termination; (b) the continued existence and the validity of the rights and obligations of the parties under clause 5; and (c) any provisions of this Agreement necessary for the interpretation or enforcement of this Agreement.

9. Dispute Resolution

9.1 Subject to sub-clause 9.3, if a dispute arises out of or in connection with this Agreement, the parties shall: (a) within 30 days of written notice of the dispute being received by the receiving party in good faith seek to resolve the dispute through negotiations between the parties' senior representatives who have the authority to settle it; and (b) not pursue any other remedies available to them until at least 30 days after the first written notification of the dispute.

9.2 The appointed representatives shall use reasonable endeavours to resolve the dispute. If the dispute is not resolved in accordance with this clause, either party may propose to the other in writing that the matter be referred to a non-binding mediation. If the parties are unable to agree on a mediator either party may apply to the Centre for Dispute Resolution (CEDR) to appoint one.

9.3 Nothing in this clause shall prevent any party from having recourse to a court of competent jurisdiction for the sole purpose of seeking a preliminary injunction or such other provisional judicial relief as it considers necessary to avoid irreparable damage.

10. General

10.1 This Agreement (and any appendices attached to it) sets out the entire agreement and understanding between the parties and supersedes all prior agreements, understandings or arrangements (whether oral or written) in respect of the subject matter of this Agreement.

10.2 To the extent that any provision of this Agreement is found by any court or competent authority to be invalid, unlawful or unenforceable in any jurisdiction, that provision shall be deemed not to be a part of this Agreement, it shall not affect the enforceability of the remainder of this Agreement nor shall it affect the validity, lawfulness or enforceability of that provision in any other jurisdiction.

10.3 The rights, powers and remedies conferred on either party by this Agreement and the remedies available to either party are cumulative and are additional to any right, power or remedy which it may have under general law or otherwise.

10.4 Either party may, in whole or in part, release, compound, compromise, waive, or postpone, in its absolute discretion, any liability owed to it or right granted to it in this Agreement by the other party without in any way prejudicing or affecting its rights in respect of that or any other liability or right not so released, compounded, compromised, waived or postponed.

10.5 The Energy Partner acknowledges that it has entered into this Agreement in reliance only upon the representations, warranties, conditions and promises specifically contained or incorporated in this Agreement and, subject to clause 10.6, WPD shall have no liability to the Energy Partner in respect of any other representation, warranty, condition or promise made prior to the date of this Agreement, unless it was made fraudulently, or implied into this Agreement.

10.6 Nothing in this Agreement shall limit or exclude either party's liability for death or personal injury caused by its negligence, or the negligence of its employees, agents or subcontractors; its fraud or fraudulent misrepresentation; and any other liability which cannot by law be excluded or limited.

10.7 No single or partial exercise, or failure or delay in exercising any right, power or remedy by either party shall constitute a waiver by that party of, or impair or preclude any further exercise of, that or any right, power or remedy arising under this Agreement or otherwise.

10.8 No announcement concerning the terms of this Agreement shall be made by or on behalf of either party without the prior written consent of the other, such consent not to be unreasonably withheld or delayed.

10.9 Nothing in this Agreement or in any document referred to in it or in any arrangement contemplated by it shall create a partnership or joint venture between the parties or render a party the agent of the other, nor shall a party hold itself out as such (whether by an oral or written representation or by any other conduct) and neither party shall enter into or have authority to enter into any engagement, or make any representation or warranty on behalf of, or pledge the credit of, or otherwise bind or oblige the other party.

10.10 This Agreement may be executed in any number of counterparts and by the parties on separate counterparts, but shall not be effective until each party has executed at least one counterpart. Each counterpart, when executed, shall be an original of this Agreement and all counterparts shall together constitute one instrument.

10.11 Any notice to either party under this Agreement shall be in writing signed by or on behalf of the party giving it and shall, unless delivered to the party personally, be left at, or sent by prepaid first class post or prepaid recorded delivery to the address of the party as set out on the front page of this Agreement or as otherwise notified in writing from time to time. A notice shall be deemed to have been served at the time of delivery, if delivered personally, or 48 hours after posting.

10.12 No term of this Agreement is enforceable pursuant to the Contracts (Rights of Third Parties) Act 1999 by any person who is not a party to it.

10.13 This Agreement and any dispute, claim or obligation (whether contractual or non-contractual) arising out of or in connection with it, its subject matter or formation shall be governed by the laws of England and Wales.

10.14 Subject to clause 9, the parties irrevocably agree that the courts of England and Wales shall have exclusive jurisdiction to settle any dispute or claim (whether contractual or non-contractual) arising out of or in connection with this Agreement, its subject matter or formation.

This Agreement has been signed on the date stated as the "Date of Agreement" on the front page of this Agreement.

Western Power Distribution (East Midlands) plc
Registered in England and Wales No. 2366923
Registered Office: Avonbank, Feeder Road, Bristol BS2 0TB

Western Power Distribution (West Midlands) plc
Registered in England and Wales No. 3600574
Registered Office: Avonbank, Feeder Road, Bristol BS2 0TB

Western Power Distribution (South West) plc
Registered in England and Wales No. 2366894
Registered Office: Avonbank, Feeder Road, Bristol BS2 0TB

Western Power Distribution (South Wales) plc
Registered in Wales No. 2366985
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IVHM ALSTOM CGI Aston University CISCO