Annexe C: Smart Solutions for Smart Grid Evaluation Framework

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Document: Smart Solutions for Smart Grid Evaluation Framework

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Contents

1 Introduction

This document incorporates a number of smart solutions to be considered in the Smart Grid Evaluation Framework.

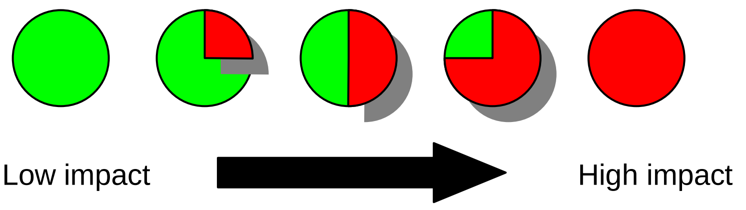
The smart solutions considered in this document are:

- Electrical Energy Storage
- Dynamic Thermal Ratings
  - Overhead Lines
  - Underground Cables
  - Transformers
- Enhanced Automatic Voltage Control
  -
- Demand Side Response

For each smart solution, there are a number of sub-categories where comments and analysis is provided. These are:

- Description of the technology
- Costs
- Value Chain
- Asset Life
- Timescale for Deployment
- Changes to Profile
- Headroom Released
- Impact table

The impact table is a graphical depiction of the likely effect on the thermal and voltage headroom across the three network types (urban, rural and suburban). In each case, the impact has been assessed and is indicated as follows:



In several cases, there are also accompanying comments and notes on the impact table to explain the assessments that have been made.

2 Electrical Energy Storage

2.1 Description of Technology

The storage of large amounts of electrical energy is usually accomplished by conversion of electrical energy into chemical potential energy. This is because only small quantities of electrical energy can be stored, relative to mass and volume envelopes. Electrical Energy Storage (EES) is used in many consumer devices – the technology available to network operators comprises of these plus a range of other technologies which are safer to use and more economical for utility-scale applications. EES technologies which are available for deployment trials are: lead-acid and hybrid lead-acid, lithium-ion and derivatives, sodium-sulphur, nickel-metal-hydride and flow cells. The latter comprise a range of electro-chemistries, energy being (in the ideal case) stored in tanks of liquids rather than on the battery plates themselves. They become attractive for very large-scale EES or where there is a requirement to store energy for long periods with little self-discharge.

EES technology has been receiving increased attention for the reasons that it offers an alternative to conventional reinforcement where networks are constrained by the requirement to deliver peak power for only a few hours in a day or year. EES can deliver the peak required, being charged overnight or in other period of low power, thus avoiding lengthy or costly network upgrades. EES technology is however expensive (~£3000/kW), lossy (typically 75% efficient), performance degrades over time and with the numbers of discharges required and have shorter calendar life than conventional assets.

There are alternatives to EES: pumped hydro (constrained by geography), compressed air energy storage (constrained by geology and efficiency), superconducting magnetic energy storage (short-term discharge over seconds to minutes), flywheels (discharge over tens of minutes), cryogenic energy storage (at pilot-stage), thermal energy storage (high temperature heat stores, pilot-stage) and demand-side management.

Only EES and flow batteries are considered here, the reasons being that they can deliver in the 2-4hr discharge duration that is necessary for peak lopping, that they are available in capacities small enough to cater for network operator requirements and that they do not require any specific geographical or geological features.

All EES and flow battery technology require grid connection via Power Conversion Systems (PCS). These are worthy of note as well-developed PCS are able to provide the capability to deliver or absorb reactive power to improve power factor (reduce losses), provide voltage control and act as a sink for harmonic currents (to improve voltage quality).

Table 1. EES Technologies (Publicly Available Sources)

	Pb-Acid	Ni-Cd	NaS	NaMH (sodium metal-halide)	Li-Ion	Flow
Specific Energy (Wh/kg)	35-50	70-80	100	115	110-160	15-85 Wh/l
Cycle Life (cycles)	500 to 1,500	1,500+	2,500	3,000+	2,000+	Varies
Technology Readiness Level	9	9	9	6-7	5-8	4-8
Reference Systems	c. 125MW installed capacity in relevant power utility applications	40MW Golden Valley Alaska installation	c. 300MW capacity installed in relevant power utility applications	Yet to be deployed commercially	Early stage pilot power utility installations in place.	Under 100 systems worldwide, demonstrator at Nairn
Commercial Supply Base	Wide variety of suppliers	Wide variety of suppliers	Single supplier (NGK)	ZEBRA- FZ Sonnick Durathon- GE	Limited range of early stage suppliers	Limited range of commercial suppliers
Capital Cost	$425-600/ kW	$875/kW	$1,300-2,600/kW	Yet to be announced	Yet to be announced	$1000-2000/kW

2.2 Cost

A budget cost for EES is around $1000/kW, costs for particular technologies are presented in

Table 1. Given a load growth rate of 1% per annum, a secondary distribution transformer of 800 kVA and a 50 kW system costing $50,000, with 100% availability the EES could theoretically defer reinforcement for up to 6 years. If there is a requirement for voltage control or reactive compensation at the EES site, then some of the cost can be offset against the reduced need for other equipment – provided that EES availability is good enough and that the need exists.

Most EES are today produced by foreign manufacturers, which means that extra cost and space needs to be allocated to cater for interposing transformers and other adaptations necessary for UK application.

2.3 Value Chain

The unbundled electricity supply system in the UK means that any one entity or company cannot capture the full benefits of EES (i.e. frequency response, asset deferral, power quality improvement etc). Due to the high capital cost, the only applications that today seem to justify (for a single entity) the deployment of EES are those of deferral of reinforcement, asset life extension and in some cases, backup power supplies. These drive deployment by network operators alone. Whilst arbitrage is often used to illustrate the benefits of storage (buy low, sell high) it requires frequent, high price-differentials to repay its capital cost.

2.4 Asset Life

EES asset life is electrochemically limited by the number of charge/discharge cycles that the technology can sustain without severe performance degradation. The chemicals used are highly reactive; with every cycle the chemically active parts pollute to some degree, such that over the course of time, performance suffers. In this respect, flow cells offer the greatest potential for longevity as the active parts can be replaced or refreshed to renew performance. As life depends on cycles, limiting the number of cycles necessary to provide upgrade deferment by a form of intelligent control may be necessary.

Referring to

Table 1, considering daily cycles used for peak lopping over one-quarter of a year, the various technologies would have calendar lives (determined from cycle numbers per year) of up to 15 years for lead-acid and up to 30 years for sodium metal-halide.

2.5 Timescale for Deployment

EES are typically available with 6-month or less lead-time, which is about equivalent to the amount of time that should be allocated for pre-installation project and site preparation, fire, operation and safety procedures. Deployment requires suitable space to be available. Compared to reinforcement, there should be no need for planning processes where EES are located at substations and most types of EES could be relocated or expanded in a modular manner as the need to peak lop changes over time. Given the interest in EES and the relatively limited supply capacity for utility-scale applications, availability will be subject to global markets.

2.6 Changes to Profile

EES can be called upon to adjust any existing demand profile to bring it above/below network constraints. Note that to ensure longevity of the solution, the number of charge/discharge cycles should be minimised – i.e. one charge cycle per night and one discharge cycle at peak times.

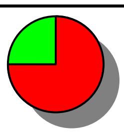
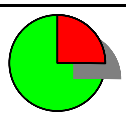
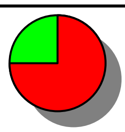
2.7 Headroom Released

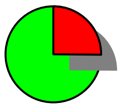
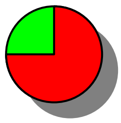
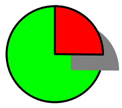
For the typical figure of $1000/kW and assuming dollar parity, the amount of thermal headroom released for a £50k capital investment is 50,000/1000 = 50 kW. As described, at a constant 1% growth in load, this would provide 6 years of load-growth-deferral at an 800 kVA transformer.

In terms of voltage headroom, on LV, EES would typically be used to cater for the peak generation or load of PV systems or EVs. EES could be triggered by high or low voltages, time of day/season, solar sensors and the like to reduce peak load or generation. Given an 800 kVA transformer of 5% impedance, a voltage of 12V is developed on 240V at full load (5%*240V). A 50 kW EES device would reduce power through the transformer *in both directions*, effectively creating a control range of

2 x (50kW / 800kW) x 5% x 240V = 1.5 V.

2.8 Impact Table

Electrical Energy Storage	**Urban**	**Rural**	**Suburban**
Thermal Headroom			

Voltage Headroom			

Urban and suburban networks – strong with relatively little voltage change from EES hence significant thermal headroom impact and little voltage headroom impact.

Rural networks – the opposite scenario to that described above is true.

3 Dynamic Thermal Ratings

3.1 Overhead Lines

3.1.1 Description of Technology

Dynamic Thermal Ratings (which, in this sense, can also be called Real Time Thermal Ratings) refers to techniques by which the maximum capacity of various network components can be assessed in real time in response to local environmental conditions, such as temperature, for example. Dynamic Thermal Ratings have been applied to overhead lines in a number of cases, although this application has tended to be on high voltage lines (as opposed to LV) to facilitate the connection of additional renewable generation to a distribution network without the need for costly reconductoring to increase the capacity of the overhead line.

An advantage of considering Dynamic Thermal Ratings for wind generators is that wind generation is obviously operating at maximum export when conditions are windy, which also happens to be when the cooling effect on the line is greatest (assuming that the line is sufficiently close to the wind farm as to experience the same weather conditions). As it is sometimes the case that network issues will only arise at times of maximum export during certain periods of the year, it is possible to mitigate this risk by applying a dynamic rating to the line to allow it to carry additional current during favourable conditions. Two demonstration projects are on SSE's distribution network on Orkney and on WPD's network near Skegness.[1]

Care still needs to be exercised when considering increasing the rating of overhead lines as when higher currents are carried, the amount of sag in the line increases. Excessive currents may, therefore, impinge on minimum clearances and could cause annealing of the conductor. Studies must therefore be undertaken of the circuit in question before increasing the rating of the overhead line.

Overhead lines are arguably the most attractive asset group for Dynamic Thermal Ratings. This is because they are most exposed to ambient conditions and therefore offer the greatest benefit in terms of rating enhancement. This is reflected in the fact that the majority of "off-the-shelf" dynamic rating solutions currently available focus on applications to overhead lines.

[1] S5211 Active Network Management Solutions Implementation Document - Dynamic Line Ratings, M.Gillie (December 2009)

When considering Dynamic Thermal Ratings, an important parameter to consider is that of the thermal time constant of the asset. This governs the necessary speed of response for reconfiguring an overloaded network, defines how quickly the ratings can alter with changing conditions and describes the extent to which the real-time rating is dependent upon previous events. The amount and duration of short term overload current that can be applied to the line is also heavily dependent on the time constant. The time constant for distribution network overhead lines is relatively short, being of the order of five to ten minutes[1].

3.1.2 Cost

Costs for Dynamic Thermal Rating systems vary according to their complexity, but an example system that could be applied to an 11kV overhead line with three modules, a weather station, software and local data collector would cost in the region of £4000. Other, more complex systems that are more expensive are also available.

3.1.3 Value Chain

It is envisaged that Dynamic Thermal Rating solutions deployed on overhead lines will largely be at the cost of the network operator. However, a supplier or generator connected to the particular portion of network concerned may provide some level of demand or generation control.

3.1.4 Asset Life

At present, asset life is something of an unknown. The equipment is designed to act in a “fit and forget” manner without the requirement for ongoing maintenance.

It is assumed that the life of the equipment for overhead line dynamic thermal ratings solutions (i.e. “power donuts”, CTs etc) would be of the order of 15 years.

3.1.5 Timescale for Deployment

At present, a scheme for implementation on an overhead line operating at 11kV has a lead time of approximately six months and takes around two days to install.

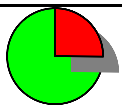
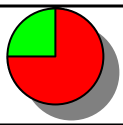
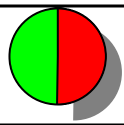
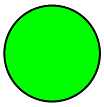
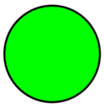
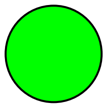
3.1.6 Changes to Profile

Dynamic Thermal Ratings are effective in that they increase the capacity of the network, thereby increasing the level of thermal headroom available. This is normally achieved without altering the demand profile itself, although it could be combined with some form of Demand Side Response to reduce demand at times when the permissible rating of the line is low.

3.1.7 Headroom Released

The amount of thermal headroom that can be released depends on the topography of the network and the surrounding area. For example, lines across open fields can have their rating increased more than those running through wooded areas. The amount by which the rating is increased also depends on the speed of response of any associated demand or generation control. However, for a line across open ground an increase in rating of 30% can be expected.

3.1.8 Impact Table

Dynamic Thermal Ratings	**Urban**	**Rural**	**Suburban**
Thermal Headroom			
Voltage Headroom			

The values in the table above reflect the fact that overhead lines are more prevalent in rural than urban areas. Thus far, the technique has been deployed on HV overhead lines rather than LV, but a benefit can still be realised by applying the solution to, say, an 11kV line feeding a village that is then supplied with underground cables at LV.

3.2 Underground Cables

3.2.1 Description of Technology

As described in 3.1.1, Dynamic Thermal Ratings refers to techniques to assess in real time the maximum capacity of network components in response to local environmental conditions.

The focus of applications of dynamic ratings in the UK to date has been on overhead lines, primarily to facilitate more wind farm connections without costly reinforcement. There are no known UK trials of dynamic ratings for cables to date. However, the thermal time constants of OHLs are short compared with underground cable and transformers.

The main concern when considering applying enhanced ratings to underground cables is that excessive currents may cause joints to fail or damage to the insulation due to overheating.

The time constant for underground cables is of the order of hours and days[2], which can be compared to that of overhead lines which is of the order of minutes.

3.2.2 Cost

At present, this technology is unproven at 11kV and LV, and there are no known installations of dynamic rating for cables in the UK. Cost of implementation of such a scheme is therefore unknown at the present time.

[2] S5145 Dynamic Circuit ratings M.Gillie April 2005

3.2.3 Value Chain

As for dynamic ratings applied to overhead lines, it is likely that any scheme would be installed by the network operator and would therefore be at the DNO's cost. A supplier and/or generator may also be involved if either party was contributing to the scheme by way of demand control at times of low thermal rating.

3.2.4 Asset Life

This is unknown at present, given that the technology is yet to be deployed. It is envisaged that it will be "fit and forget" with no maintenance requirements.

It is envisaged that a reasonable asset life for the sort of equipment associated with dynamically rating underground cables (temperature probes etc) would be of the order of 15 years.

3.2.5 Timescale for Deployment

Unknown at this stage as the technology is not yet market-ready.

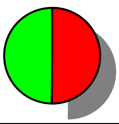
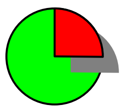
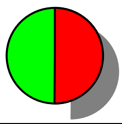
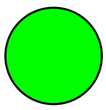
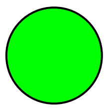
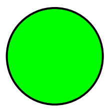
3.2.6 Changes to Profile

As for overhead lines, dynamic ratings seek to increase the available headroom by enhancing the rating of the cable rather than directly affecting the demand profile of the circuit. It may be combined with some Demand Side Response in certain circumstances, but this will be on a case-by-case basis.

3.2.7 Headroom Released

At present this is not a well-defined quantity, but it is envisaged that ratings could be enhanced by approximately 10% (considerably less than that available via applying dynamic ratings to overhead lines). This will again be dependent to a degree on the speed of any available demand or generation control on the network.

3.2.8 Impact Table

Dynamic Thermal Ratings	**Urban**	**Rural**	**Suburban**
Thermal Headroom			
Voltage Headroom			

The cost benefit analysis of using dynamic ratings for underground cables is yet to be proven, but cables and thermal capacity are unlikely to be drivers for reinforcement on rural networks, hence the low impact here.

3.3 Transformers

3.3.1 Description of Technology

As described in 3.1.1, Dynamic Thermal Ratings refers to techniques to assess in real time the maximum capacity of network components in response to local environmental conditions. The operating temperature of a transformer dictates its ageing rate, which is the rate of deterioration of the insulation. The temperature at which the transformer is operating is dependent on the current being carried, the ambient temperature and rate of cooling.

When a transformer is manufactured, it is tested to confirm that it should be capable of continuous operation at rated load at a defined ambient temperature for its stated lifetime. If the transformer happens to be operated in more favourable conditions (with a reduced load and/or at a lower ambient temperature) then a slower ageing rate is achieved. Conversely, a transformer may be loaded above its nameplate rating (i.e. subjected to higher currents) if the network operator is willing to accept the accelerated ageing that would ensue for that period. Hence, it follows that it is also possible to maintain the normal ageing rate whilst continuously overloading the transformer, provided that the ambient temperature is lower.

The international standard IEC 60076 Part 7 defines the loading limitations for three power categories of oil-immersed transformer (distribution, medium-power and large) and gives standard thermal models to can be used as the basis for dynamic rating calculations. The guidelines can be used to derive ratings for transformers that do not expose the network operator to unacceptable risk of failure.

However, care must be taken as transformers at primary level and above (operating at voltages of 33/11kV, for example) are standardly fitted with an On Load Tap Changer (OLTC). This component does not always have the same potential rating as the transformer windings, hence if the transformer is to be operated at a higher load, it must be ensured that the tap-changer is capable of carrying the load.

The load that a transformer can carry for the same rate of ageing is generally higher in winter than in summer (as a result of lower ambient temperature) which, for many applications in the UK, correlates to when loads are likely to be higher.

Assuming the transformer is ground-mounted indoors; ratings can be calculated using the following parameters:

- Load;
- Voltage (used to calculate no-load losses and is constant);
- Winding temperature;
- Ambient temperature.

The rating of an external or pole-mounted transformer would also be affected by environmental conditions such as wind speed and solar gain.

Measurement of winding temperature is seldom feasible for an existing transformer, as retro-fitting probes is difficult. However winding temperature can be predicted from oil temperature, as defined in IEC 60076 Part 7. Oil temperature can be measured at the top or bottom of the reservoir, or an oil pocket. Tank surface temperature can be used to infer the oil or winding temperature with reduced accuracy.

As described earlier, the thermal time constant of the asset is an important parameter for dynamic thermal rating as it defines how quickly the ratings can alter with changing conditions and describes the extent to which the rating is dependent upon previous events. The time constant is, several hours for transformers[3]. This is significantly longer than that of overhead lines, meaning that previous loading is a significant factor for dynamic thermal rating of transformers.

3.3.2 Cost

The cost of providing dynamic thermal ratings on transformers varies according to the transformer controller installed and the level of monitors already in place. Generally, the cost will be of the order of several thousand pounds.

3.3.3 Value Chain

As for other applications of dynamic thermal ratings, the costs are likely to be borne by the DNO, with the potential addition of a generator or supplier providing some form of demand or generation control at times of low thermal rating.

3.3.4 Asset Life

The asset life of transformer dynamic rating schemes is unknown as yet, but it is envisaged that such schemes are designed to be “fit and forget” with no maintenance requirement.

In the case of primary transformers, the asset life should be matched to that of the transformer, hence a life of 40 years can be assumed. For secondary transformers, there is less to base assumptions on, but if oil tank temperature probes are to be used, an asset life of 20 years seems a reasonable assumption.

3.3.5 Timescale for Deployment

Lead times for suitable controllers are of the order of six months and installation of the controllers is envisaged to take between one and four days.

3.3.6 Changes to Profile

As for alternative dynamic thermal rating schemes, the demand profile itself is not directly affected. The scheme works by altering the capacity of the assets hence creating additional headroom. The demand profile will only alter if some form of generator or supplier controlled DSR is implemented at certain times to alleviate conditions when the rating is low.

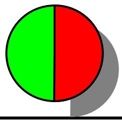
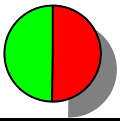
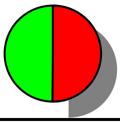
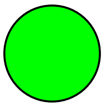
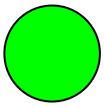
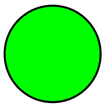
3.3.7 Headroom Released

The amount of headroom released depends on the control strategy implemented and whether the purpose of the dynamic thermal rating is primarily to reduce ageing or increase ratings. Additional capacity of 10-20% is claimed by manufacturers but few applications have yet published data. If the scheme is installed in tandem with some DSR, the headroom

[3] S5145 Dynamic Circuit ratings M. Gillie April 2005

release will also depend on the speed of response of load or generation control, i.e. how quickly demand could be reduced if necessary will govern how far the asset can be stressed above its nominal rating.

3.3.8 Impact Table

Dynamic Thermal Ratings	**Urban**	**Rural**	**Suburban**
Thermal Headroom			
Voltage Headroom			

The cost benefit of applying this technique to secondary distribution transformers (i.e. those that transform the voltage down to LV) is not yet proven and this technique would more commonly be deployed at primary transformer level. At lower voltages, transformers do not often form the pinch point of a circuit (as opposed to cables and overhead lines, for example).

4 Enhanced Automatic Voltage Control

4.1 Description of Technology

Network voltages must be maintained within strict limits as laid out in the Electricity Safety, Quality and Continuity Regulations (ESQCR). These limits, 132kV ±10%, 33/11kV ±6% and LV +10% -6%, are statutory and set out in a DNO's licence agreement. Failure to supply within these limits may result in damage to customer's equipment, exposure to safety risks, with potential repercussions to the DNO.

Conventional DNO design assumes networks to be passive with uni-directional power flows, and Automatic Voltage Control (AVC) schemes acting upon the Grid and Primary transformers (i.e. transformers at 132/33kV and 33/11kV and similar voltages) are configured to work autonomously. As the penetration levels of various Low Carbon Technologies increase, voltage changes are likely to be caused, which existing AVC schemes will struggle to adequately manage.

The coordination of network voltage is a system function, rather than a function of an individual asset. Today's off-the-shelf AVC schemes operate as independent control loops with little or no interaction with the network beyond local measurements. As the network starts to operate closer to its limits (maximising available capacity in the network and avoiding costly reinforcement), there is a need for additional automatic voltage control devices over and above those located at the Grid and Primary transformers. Moreover, the addition of smart solutions, such as electrical energy storage, dynamic thermal ratings and demand-side response form similar subsystems, which need to work in concert with the voltage control devices, either providing a local response to address an issue elsewhere or relying on a remote device (which is not under the control of the specific voltage control device) to help it perform its task. The way in which this is carried out is influenced by the control and communications architecture that is implemented.

Hence the "EAVC system" can be considered as consisting of a range of voltage control devices, both existing and new, which can be component parts of a wider network control system.
The range of EAVC solutions can control the voltage at the following locations:

- Primary transformer (EHV/HV)
- HV circuit: via an in-line voltage regulator
- HV switched capacitor bank
- Distribution transformer (HV/LV): via on load tap-changer or LV regulator
- LV circuit: via a three phase or single phase voltage regulator

4.2 Cost

The following are indicative prices of EAVC equipment for the solutions listed above.

- Primary EAVC control only (not the transformer or on load tap-changer) – Not Known
- HV in-line voltage regulator – £20k
- HV switched capacitor bank – A brick built switching station with two switched capacitor banks – £465k
- HV/LV distribution transformer EAVC
  - Distribution Transformer with on load tap-changer – Not Known
  - LV voltage regulator – £35k
- LV regulator on LV circuit
  - A single consumer single phase regulator – £2k
  - Three phase regulator installed on LV circuit at a substation or pre-installed kiosk – £20k

4.3 Value Chain

The EAVC solutions are to enable DNOs to maintain network voltages within statutory limits therefore the costs are entirely network based.

4.4 Asset Life

At present, the asset life of the various solutions is unclear. However, they are primarily “fit and forget” maintenance-free devices that would be designed to have asset life coincident with that of the plant with which they are associated. Therefore, a reasonable assumption would be that all of the solutions named above have an asset life of 40 years, with the possible exception of the HV Switched Capacitor Bank, which may be slightly shorter and is assumed here to be 30 years.

4.5 Timescale for Deployment

The indicative lead times for the equipment of each solution are:

- Primary EAVC control only (not the transformer or on load tap-changer) – 1 to 2 months
- HV in-line voltage regulator – 4 to 5 months
- HV switched capacitor bank – A brick built switching station with two switched capacitor banks – Not Known (probably years)
- HV/LV distribution transformer EAVC
  - Distribution Transformer with on load tap-changer – Not Known
  - LV voltage regulator – 2 to 3 months
- LV regulator on LV circuit
  - A single consumer single phase regulator – 4 to 5 months
  - Three phase regulator installed on LV circuit at a substation or pre-installed kiosk – 2 to 3 months

4.6 Changes to Profile

EAVC solutions are clearly designed to have a significant impact on the voltage profile, but will not provide any benefit to the thermal profile.

Of the various solutions available, the LV voltage profiles will be most heavily influenced by the HV inline regulators, HV/LV transformer with on load tap-changer and the three phase LV feeder EAVC.
The primary EAVC will have the least effect on the LV network while the switched capacitor bank will provide "chunks" of headroom that will enable the inline voltage regulator to operate towards the middle of its tap range rather than its extremes.

4.7 Headroom Released

The level of headroom to be released by EAVC solutions is generally determined by the control system. It is likely that a target voltage will be set and the EAVC will operate so as to achieve this voltage. The headroom is therefore somewhat dependent on the extent of the voltage issue that the network is experiencing.

The EAVC solutions are not designed to release thermal headroom, any thermal headroom released would be negligible.

4.8 Impact Table

EAVC	**Urban**	**Rural**	**Suburban**
Thermal Headroom			

Voltage Headroom			

Depending on the extent to which EAVC is deployed, the impact on voltage headroom can be extremely significant for any network that is experiencing voltage issues.

5 Demand Side Response

5.1 Description of Technology

Demand Side Management is any measure that results in customers making changes to the amount of energy used, the primary source of that energy or the pattern of consumption. Demand Response relates specifically to measures that impact on the pattern of consumption. The changes can be in response to price signals, be controlled remotely by third parties or take place automatically in response to changes on the electricity network. Although measures can result in permanent changes to the pattern of consumption, the term demand response usually relates to short-term, discrete changes and only these measures are considered here.

Thus, Demand Side Response is a measure that results in customers making short term, discrete, changes to their pattern of consumption. This can provide valuable resource to:

- Optimise the use of electricity from renewable resources;
- Reduce peak demand for electricity, thereby reducing the need for peak generation plant (usually fossil fired generation) which is typically used for only a few hours per year and also maximise the use of existing network assets;
- Provide support services to the System Operator to maintain the quality and security of supply.

There are a variety of mechanisms by which demand response could be implemented, including;

- A variable time of use tariff, such as critical peak pricing, whereby peak prices are applied during a pre-defined time interval on certain days of the year. The days in which the high prices will be applied are not fixed, but customers usually receiving advance warning that the high prices will be applied. Customers can then manually alter their energy consumption, or alternatively, some devices such as heating or air-conditioning systems can adjust their operation automatically (with suitable control technology).
- Customers could receive a fixed annual payment (or discount) in return for allowing a third party to remotely control their demand. This usually involves interrupting (i.e. turning off) a specific end use of energy, such as electric heating or air-conditioning loads. There is usually a predetermined limit on the number of occasions that the load can be interrupted.

- Alternatively, customers could receive a direct payment for each kWh of demand response delivered. This approach is more suited to very large customers with predictable patterns of consumptions. It is not well suited to domestic or other small customers.

5.2 Cost

5.2.1 Critical Peak Pricing Tariffs

Little evidence exists to indicate how households (and small businesses) in the UK might respond to Critical Peak Pricing tariffs. Much of the evidence on the impact of such pricing structures would suggest that large price differentials (i.e. where the prices during critical events are 5 to 10 times higher than the lowest rate) are required to deliver significant (more than 10%) peak load reductions[4].

In the UK, the electricity supply market is fully de-regulated, and it is up to Energy Suppliers themselves to design their tariffs, there appears to be no move to mandate time of use tariffs. Therefore, it is difficult to determine the extent to which innovative ToU tariffs will be offered by Energy Suppliers in the UK. It is considered unlikely that energy suppliers will want to promote new, potentially complex tariffs at the same time as the roll out of smart meters – otherwise, there is a risk of repeating some of the experiences of Victoria, Australia [5, 6], and PG&E, California [7].

Critical peak pricing or other variable time of use tariff is the best suited to Energy Suppliers. The charges levied by DNOs to recover the costs associated with distributing electricity to end-users (known as Distribution Use of System (DUoS) charges) are collected by Energy Suppliers rather than directly via the DNOs. Therefore, it is it is up to the Energy Suppliers how these charges are bundled together with the energy tariff for HV and LV customers. Whereas DNOs have introduced ToU distribution charging for HV and LV customers with half-hourly metering (i.e. with maximum demands above 100kW), such charging is not in place for domestic and small commercial users. These customers are currently charged on a flat unit rate, or a two rate tariff for those on an off peak tariff. As outlined in the section on '*smart meter data information'*, it is not yet clear whether Smart Meters will be able support time of use network charging.

5.2.2 Fixed Annual Payments

Fixed annual payments are a relatively straightforward way to promote demand response. They are not complex to administer as no metering is required to monitor the amount of electricity delivered. Such an approach is best suited to a specific end use of energy, typically large industrial loads. This approach is adopted by National Grid when procuring frequency response services. Thus, customers receive a fixed annual payment in return for

[4] Research Report No 5: The Role of Advanced Metering and Load Control in Supporting Electricity Networks, Network Driven DSM, Task XV of the IEA DSM Program

[5] Plug pulled on smart meter plan, Article by Paul Austin, March 2010, The Age, available at http://www.theage.com.au

[6] Our demand: reducing electricity use in Victoria through demand management, Sachdeva / Wallis, Report 10/4, August 2010, Monash University and Monash Sustainability Institute

[7] http://www.greentechmedia.com/articles/read/pge-sued-over-smart-meters-slows-down-bakersfield-deployment/ accessed 10 March 2011

having a specified load available for demand response, but receive no further payment for any interruptions incurred. The level of payments are in the region of £19MW/ hour.

The same approach could be extended to domestic refrigeration equipment, which could be fitted with frequency relays to allow their operation to be adjusted in response to changes in network frequency. Analysis of the costs and benefits of such an approach suggest that the component costs would be around £4 per fridge, excluding development costs, and the market value of balancing demand provided would be about £30 per fridge per during its lifetime, earning about £3 per year over the 17 year average lifespan of the appliance[8].

This approach is probably the most straightforward from a DNO perspective. However, the level of payments could be very low. Analysis undertaken into the level of payments that may be made to domestic customers who participate in DSR to assist a DNO defer network investment shows that the level of payments could be between £29 and £200 depending on how the benefits of the investment deferral is shared between the customer and DNO, and this level of payment is only viable in certain scenarios. In other scenarios DSR intervention is not financially viable.

5.2.3 Direct Payments

Direct payments are an alternative approach for procuring demand response services required on an ad-hoc basis. Thus, customers only receive a payment when a demand service is delivered. The main difficulty of this approach is the requirement to meter the amount of demand response delivered. As such, it is best suited to large, predicable energy end uses. Otherwise, measuring the amount of energy ‘not consumed’ is difficult. This is especially true for domestic customers, even where half-hourly metering is available. This approach is adopted by National Grid when securing Short Term Operating Reserve, and payments are typically around £256/MWh of demand response delivered[9]. A domestic customer providing around 500W of demand response for half an hour per day, 5 days per week over the winter period, would equate to a total payment of around £5/year.

5.3 Value Chain

The following diagrams illustrate some of the potential commercial models for the implementation of Demand Side Response by DNO.

5.3.1 Model 1

In this first model the DNO contracts directly with householders. Their relationship with the householder is distinct from the householder’s relationship with their energy supplier. The DNO can choose which householders they wish to make contract with regardless of the householder’s energy supplier. The DNO may therefore approach householders directly based on criteria of their choosing such as location or load type. The diagram below illustrates the value chain for this model. Payment passes directly between the DNO and the householder. A flow of information may be necessary between the energy supplier and the DNO, and the householder and the energy supplier however the energy suppler is not part of the commercial relationship.

[8] www.dynamicdemand.co.uk/pdf_economic_case.pdf (accessed 18 October 2011)

[9] Monthly Balancing Services Summary 2010/2011, February 2011, National Grid, p7

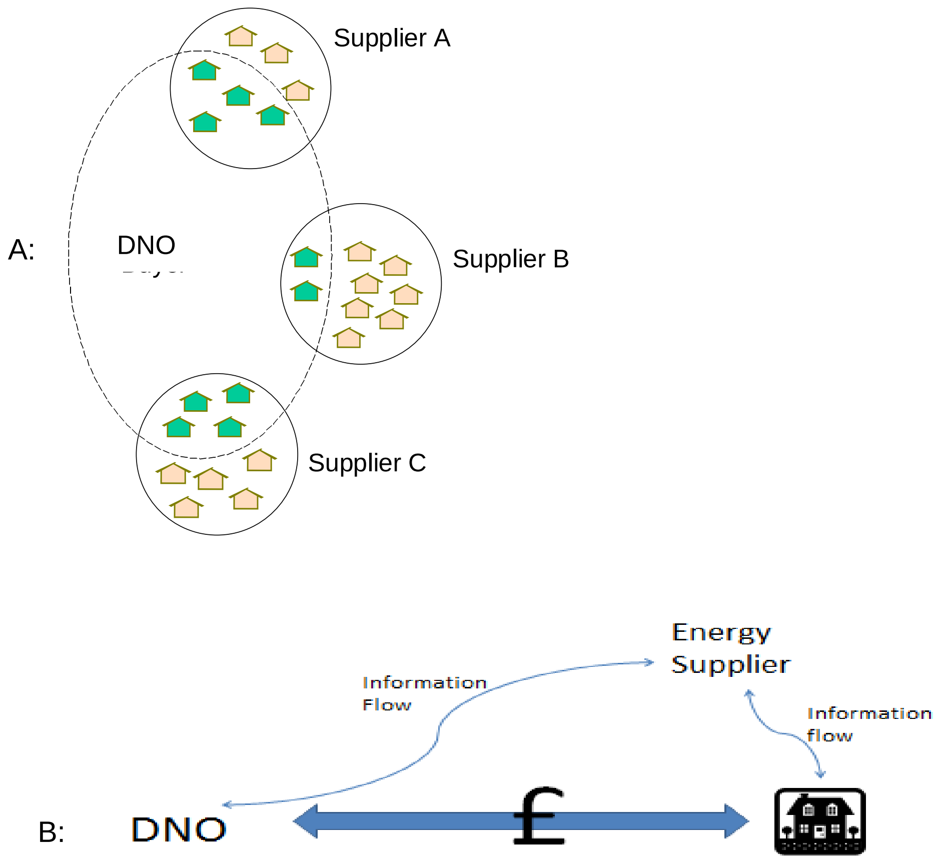
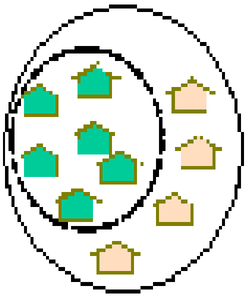


Fig 1: Value Chain for Model 1

5.3.2 Model 2

In this second model, the householder's relationship for providing Demand Side services is with their energy supplier. The DNO contracts with the energy supplier to purchase Demand Side services. Households within a DNO's area will be with different energy suppliers potentially requiring the DNO to contract with more than one energy suppliers. The DNO may not be as free to target particular householders. Figure 2 (part B) illustrates this commercial relationship.

A:



Energy supplier acts as 'buyer'

B:

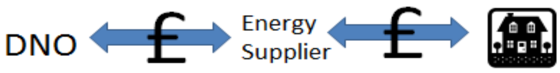


Fig 2: Value Chain for Model 2

5.3.3 Model 3

In this third model a demand aggregator acts as a buyer of Demand Side services. The aggregator can purchase services from householders contracted to different energy suppliers. The DNO may contract with a single aggregator and may be able to specify particular requirements. There may be a flow of information to the energy supplier from any of the involved parties, but the energy supplier is not part of the contract or the value flow, as demonstrated in Figure 3 (part B).

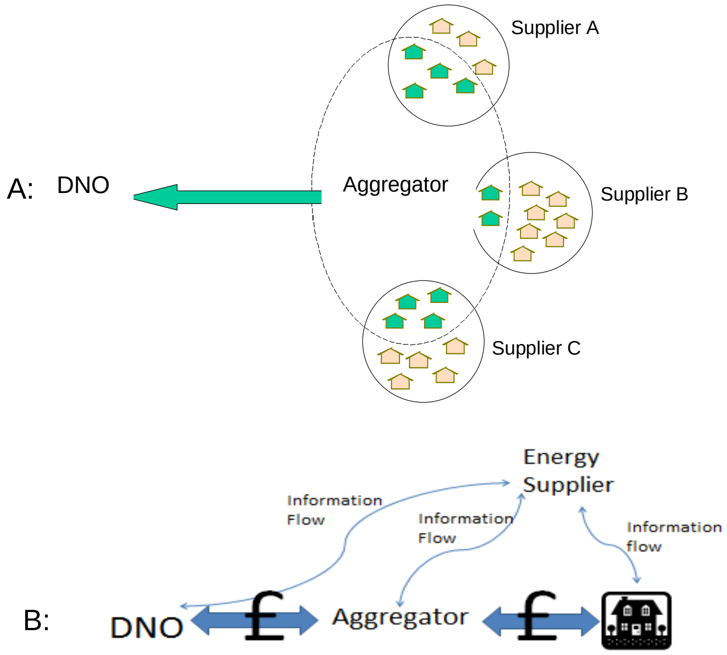


Fig 3: Value Chain for Model 3

5.4 Asset Life

The asset life of DSR solutions could depend on a range of issues. For example, if the DSR implementation is covered by a contract between, say the DNO and the customer, then it would be reasonable to expect such a contract to exist for a period of 12 months, after which it might be reviewed.

However, the asset life could also be considered to be the life of the appliance which is providing the demand reduction. Therefore, if the DSR implementation is resulting in various smart appliances such as washing machines and dishwashers being switched off, the asset life could be regarded as the life of these appliances. If any one of these appliances failed, then it would not mean that DSR was unavailable, merely that the amount of demand that could be switched would be reduced.

A third consideration is that the asset life be governed by the controlling device in the home that interfaces between the home area network and the wider network. This controller is likely to take the form of an electronic device installed at the meter and will have a certain asset life (perhaps 10 years). If this were to fail then no DSR would be achieved meaning that perhaps this should be considered as the “true” determining factor of asset life.

5.5 Timescale for Deployment

Table 2. Timescale for roll-out of various Demand Response techniques

Demand Response	Supplier Roll-Out	DNO Roll-Out
Critical Peak Pricing		
Requirements	Smart metering Half-hourly settlement of energy consumption (*)	Smart metering with separate registers to enable implementation of time of use network tariffs.
Earliest roll-out	2019 at the earliest provided there is a move to half-hourly settlement rather than profile settlement.	2019 at the earliest
Direct Payment	Within a relatively short timescale, 2 to 3 years	Within a relatively short timescale, 2 to 3 years
Fixed Payment	Within a relatively short timescale, 2 to 3 years	Within a relatively short timescale, 2 to 3 years

(*) Under the current arrangements, the pattern of consumption of customers is determined according to a profile, and total consumption is allocated to specific half-hours according to these profiles. Customers are classified into one of eight profile classes. However, within these classes, customers with demand management are treated in the same way as customers without demand management. This is regarded to have been a major barrier to the introduction of innovative tariffs or direct load control schemes since the system was introduced in 1998.

The introduction of Smart Meters means that it will be possible for all electricity consumption to be settled according to their actual profile, rather than a 'deemed' profile. However, there is no requirement on Energy Suppliers to move away from the use of the current profiling system for domestic customers and some small non-domestic customers[10], although they are able to do so if they wish.

5.6 Changes to Profile

The diagram below (Fig 4) represents the average load profile of a household in the UK. Thus, the maximum demand of a single household over a half-hour interval is around 1 to 1.5 kW. The actual maximum demand will be much higher, but is smoothed out when averaged over a number of households and over each half-hour settlement period. The STP project Long Term Domestic Demands[11] provides an estimate of how this pattern of demand is broken down by different end use category. This suggests that the maximum demand

[10] A proposal to introduce half-hourly settlement for all customers currently in profile classes 5 to 8 is pending, but no such requirements are yet proposed for customers in profile classes 1 to 4 which includes domestic customers however Elexon launched a Consultation and Impact Assessment into the implications of mandatory half hourly settlement for profile classes 1-4 in July 2011.

[11] S5207 Long Term Domestic Demands, D Roberts (2010)

available for demand response at the time of the system peak is likely to be around 155W, and includes the following potential end use loads (which could be managed through smart appliances):

- Wet appliances
- Refrigeration

Convenience loads such as home computing products and consumer electronics make up about one third of the domestic load. It is unknown how much of this demand could be shifted away from the peak if consumers were to consider charging battery operated goods such as laptops and mobile phones overnight.

For other customers, for example commercial and or industrial customers, the amount of demand response available depends very much on individual customers. It is not possible to generalise across such a diverse group of customers.

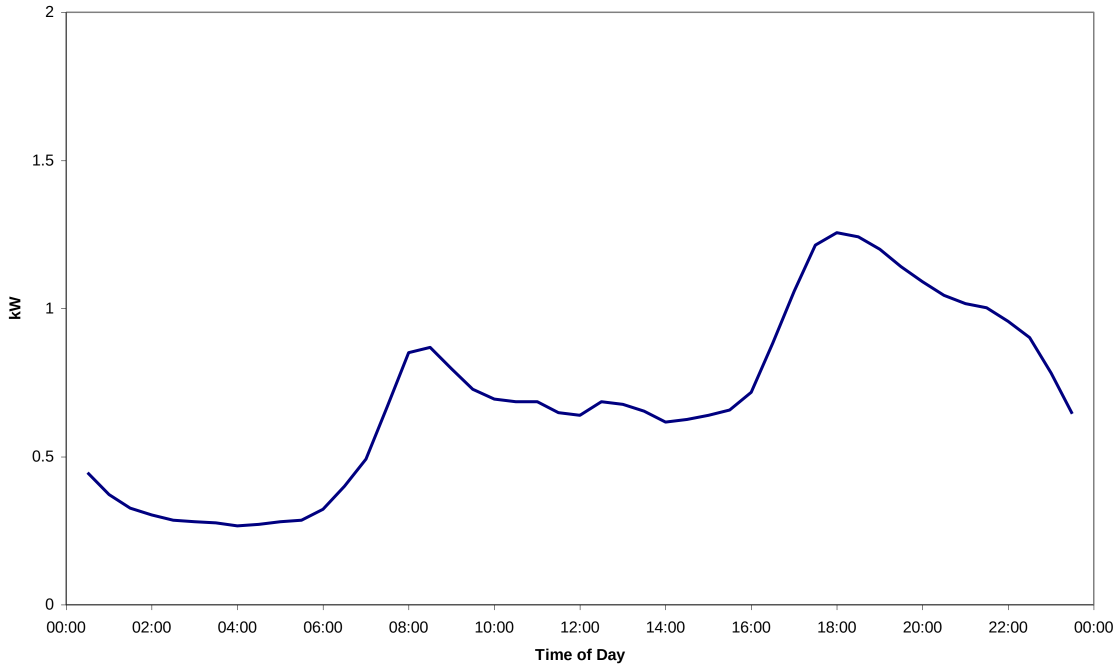


Fig 4. Standard domestic daily load profile

When demand response is applied (possibly through the use of smart appliances) the peak will be reduced, but the load will have to be picked up elsewhere. For example, if appliances such as washing machines and dishwashers are interrupted at time of peak demand (around 6pm), it will be unacceptable to customers if this interruption persists until a time when load has significantly reduced (e.g. 10pm). The customer will have a level of expectation that these appliances will have finished their operation within a reasonable time, meaning that the peak is likely to be flattened over a fairly narrow window of time (maybe until 8pm).

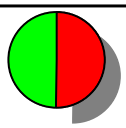
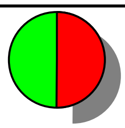
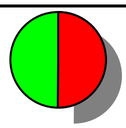
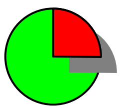
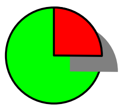
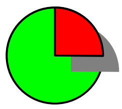
No trials of smart appliances or surveys of acceptable levels of interruptions to appliances have yet been carried out. It is unclear at present whether there will only be certain points in the cycle of an appliance's operation when it can be interrupted. For example, if a washing machine has filled with water and heated that water to a certain temperature when it receives a signal to be interrupted, it would not be an efficient use of energy for that appliance to switch off instantly, only to have to immediately reheat the water when it switches on again. Instead, there may be some defined “break points” in a cycle when the appliance can be turned off and the demand reduced.

This level of uncertainty around smart appliances makes attempting to forecast the amount of headroom to be released and the effect on the demand profile difficult to judge at this stage.

5.7 Headroom Released

As stated in 5.6 above, it is envisaged that DSR could release approximately 155W of a total daily peak load of between 1 and 1.5kW. This represents a maximum release of approximately 10% – 15%, although the actual amount to be released is likely to be less than this as not all of the demand that could be constrained will necessarily be constrained simultaneously. Therefore, a more realistic figure might be 5 – 10%.

5.8 Impact Table

Demand Side Response	**Urban**	**Rural**	**Suburban**
Thermal Headroom			
Voltage Headroom			

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