Sustainability First
GB Electricity Demand Project – *realising the resource*

Paper 10

The Electricity Demand-Side and Local Energy : how does the electricity system treat 'local' ?

By Judith Ward & Rebekah Phillips
Sustainability First

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Sponsored by : BEAMA ; British Gas ; Consumer Futures ; EDF Energy; Elexon ; e-Meter Siemens ; E.ON UK ; National Grid ; Northern Powergrid ; Ofgem ; Scottish Power Energy Networks ; UK Power Networks ; Vodafone.

Smart Demand Forum Participants : Sponsor Group ; Energy Intensive Users' Group ; Consumer Futures ; Which ? ; National Energy Action ; Ofgem ; DECC ; Sustainability First.

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Preface

Sustainability First

Sustainability First is a UK environment think-tank with a focus on practical policy development in the areas of sustainable energy, waste and water. Sustainability First undertakes research, publishes papers and organises policy seminars. It is a registered charity with independent trustees – www.sustainabilityfirst.org.uk.

Since 2006, Sustainability First has produced a series of major multi-sponsor studies on GB household smart energy meters and brings significant knowledge and insight in the fields of energy efficiency, smart metering, smart energy tariffs and demand response.[1]

The Sustainability First project '**GB Electricity Demand – *realising the resource*'** is a three-year multi-partner project (2011-2014) focusing on the potential resource which the electricity demand side (industrial, commercial and household customers) could bring to the GB electricity market, through both demand response and demand reduction.

Key themes for the project include:

- Customer Response and Consumer Issues.
- Commercial and Regulatory Issues.
- Public Policy Issues.

The project was supported in its first year under the Northern Powergrid Low Carbon Network Fund project - and thereafter for a further two years to 2014 via a multi-sponsor group.

Sponsors include : BEAMA ; British Gas ; Consumer Futures ; EDF Energy; Elexon; e-Meter Siemens ; E.ON UK ; National Grid ; Northern Powergrid ; Ofgem ; Scottish Power Energy Networks ; UK Power Networks ; Vodafone.

Work is coordinated through a **Smart Demand Forum,** whose participants include the sponsor group together with Ofgem, DECC and key consumer bodies: Energy Intensive Users Group, Consumer Futures, Which? and National Energy Action.

[1] Sustainability First published smart meter papers are available on the website – www.sustainabilityfirst.org.uk

The project is:

- Evaluating and understanding the potential GB electricity demand-side resource across all economic sectors (including the role of distributed generation and micro-generation) ;
- Developing a clearer understanding of the economic value of this resource to different market actors and to different customers over the next 10-15 years ;
- Evaluating the key customer, consumer, commercial, regulatory and policy issues and interactions.

The project is developing a substantive knowledge-base, and provides visibility and thought-leadership for GB electricity demand-side issues. The project is undertaking work relevant to:

- GB smart meter deployment.
- Low Carbon Network Fund and Network Innovation Competition projects.
- Electricity Market Reform proposals for the electricity demand-side (DSR & electricity demand reduction).

The work programme is being delivered through the Smart Demand Forum, through wider stakeholder events, and through twelve published papers.

The project also draws upon relevant information from demand side developments in other countries to inform its work (notably the EU, US and Australia).

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GB Electricity Demand project papers – available at www.sustainabilityfirst.org.uk	
1	**GB Electricity Demand – context and 2010 baseline data.**
2	**GB Electricity Demand 2010 and 2025 – Initial Brattle Demand-Side Model : scope for demand reduction and flexible response.**
3	**What demand-side services could customers offer?** • **Household customers.** • **Industry customers.**
4	**What demand-side services can provide value to the electricity sector?**
5	**The electricity demand-side & wider energy policy developments.**
6	**What demand-side services does Distributed Generation bring to the electricity system?**
7	**Evolution of commercial arrangements for more active customer & consumer involvement in the electricity demand-side.**
8	**Electricity demand and household consumer issues.**
9	**GB Electricity Demand – 2012 and 2025. Impacts of demand reduction and demand shifting on wholesale prices and carbon emissions.** **Results of updated Brattle modelling.**
10	**The electricity demand-side and local energy: how does the electricity system treat 'local'?**
11	**How could electricity demand-side innovation serve the electricity customer in the longer term?** (to be published Spring 2014).
12	**The electricity demand-side and the GB electricity markets - bringing it all together.** (to be published June 2014).

The Electricity Demand-Side and Local Energy : How does the electricity system treat 'local' ?

Structure of this paper

This paper aims to answer two basic questions.

(1) How might the electricity demand-side play a more active role *at a local level* ?

(2) How might a better local 'match' be achieved between local generation and local electricity customers ?

Part I – pulls together main conclusions and suggested next steps for those interested in our headline findings (pp. 6-27).

Part II – takes a detailed look at underlying commercial and regulatory areas to be tackled before a *local* GB demand-side is likely to be realised at scale. Part II discusses what 'local' presently means to different market actors : to suppliers, the transmission networks, system operator, and the distribution networks. It considers how today's centralised electricity industry commercial frameworks, charges and administrative arrangements treat local generators and end-customers - *in terms of their physical impacts and location*. It discusses how for the future some underlying 'industry plumbing' may need to adapt to facilitate more *local* demand-side activity, and / or *local matching of supply and demand* (assuming this is both cost-efficient and generally beneficial for consumers). Part II concludes with a brief discussion of some high-level consumer issues in a more 'localised' electricity world, including potential fairness issues. (pp. 28-85).

Part III – offers a brief overview of current actions by Ofgem and the Distribution Networks to innovate and improve the 'local match' between supply and demand (pp 86-97).

Part IV – explores the reality of six local and community electricity demand-side case-studies. It concludes with some general lessons for both market actors and communities who may be looking to develop 'firm' demand-side actions as an alternative to new network and / or supply-side investment (pp 98-127).

Sustainability First is grateful to all those who kindly provided inputs to this paper, including case-study material. Responsibility for the paper and its conclusions rest with us.

The Electricity Demand-Side and Local Energy : How does the electricity system treat 'local'?

Part I – Main findings, conclusions and possible next steps

1. **Introduction.**

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3. **What more might be done to improve 'local-match' in the electricity system ?**

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5. **Lessons from community studies.**

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18. **Case-study 1: Self-contained island balancing (peak reduction)**
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Community Competition for Energy Demand Reduction. SSE EDRP

Case-study 3: Committed local community
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Case-study 4: Location-specific I&C demand turn-down scheme
Thames Valley Vision . SSE.

Case-study 5: Community self-balancing: wind to storage-heaters
Nines Project, Shetland. SSE (Northern Island New Energy Solutions)

Case-study 6: Private wire : self-balancing
Community Energy Scotland

19 **Lessons from Electricity Demand-Side Case Studies**

Annexes

Annex 1 – Distribution Codes & DUOS Charges.

Annex 2 – *Separate document*

Community Case Study for Sustainability First –
Community Demand Reduction at Substation. (SSE EDRP).

by Dr Megan McMichael. University College London.

Sustainability First
January 2014

Part I – Main findings, conclusions and possible next steps

1 Introduction

This paper aims to answer two basic questions.

(1) How might the electricity demand-side play a more active role *at a local level* ?

(2) How might a better local 'match' be achieved between local generation and local electricity customers ?

The paper seeks to understand what it may mean to be a small local generator or micro-generator; or an individual customer or a local group of customers (be that at street, neighbourhood, or wider community level) looking to make a demand-side contribution ***at a particular place or location***.

In trying to understand what changes might facilitate the *local* demand-side at scale and / or a better local match of supply and demand at scale (where these are cost efficient and of general consumer benefit) the paper considers :

- **Commercial issues for electricity suppliers** with respect to more 'local' or geographic approaches to customer supply (section 9).

- **The near-term impacts of low-carbon incentives and main *physical* costs and benefits of low-carbon technologies for the electricity distribution networks and** (section 12).

- **Present treatment of *location* for customers and distributed generators within existing electricity network charging frameworks** – for transmission and balancing charges in brief (sections 10 and 11) - but for distribution charges in particular. A key question discussed is whether, for the longer-term, greater cost-reflection in distribution network charges and, more controversially, sharper *locational* signals, could offer a practical and fair tool to support a more flexible and responsive *local* electricity demand-side (Distribution charging - sections 13-14).

- **Discussion of some high-level 'in-principle' issues for consumers in considering any future moves to (1) greater cost-reflection in network charges and (2) more local arrangements for electricity supply** (section 15).

- **Recent steps by Ofgem and the DNOs to facilitate greater participation by the local demand-side and distributed generation** (Part III).

- **Six local / community electricity demand-side case studies** – with a particular focus on **the practical lessons for market actors or others who may wish to look to local groups or communities for demand-management solutions (DSR, electricity demand reduction) as a dependable and cost-efficient alternative to network investment** (Part IV).

2 Key assumptions which under-pin this paper

This paper makes a number of basic assumptions – not discussed in detail - about the basic 'enabling' steps necessary to obtain a better **'local-match' of supply and demand at scale.**

These include :

- Smart meters
- Half-hourly data recording
- Half-hourly settlement (for 'dynamic' and / or highly individualised approaches to DSM).
- Data management – i.e. to enable far better knowledge of customer load, location etc
- Flexible load – which presently is not available at scale, especially in the household sector.
- Automated load.
- Retail tariffs able to incentivise customer flexibility.
- Customers who are 'engaged' at scale
- Appropriate consumer safeguards.

There is a **'time-line' / chronology** associated with these developments and we are still some way off. Ofgem's Smarter Markets team is working on many of these issues, which perhaps by the early 2020's may all 'come together'.

In addition to this basic set of smart enabling measures, other assumptions in this paper – also not discussed in detail - are as follows:

- Suppliers – large and small – are likely to become generally more interested in demand-side management in time – but this will depend (1) on the steps noted above and (2) a demonstrable business case.

- Retail tariffs which are time-related and / or broadly reflect wholesale prices – are likely to be central in promoting electricity system cost-efficiency (i.e. overall electricity system efficiency *is about far more than just location*).

- Transmission networks – we assume that there will be a continued long-term need for bulk power transfers.

- Low-carbon distributed generation – we assume that for both low-carbon and for commercial reasons distributed low-carbon generation will continue to operate on a 'must-run' basis (even though it may be *technically* feasible, for example, for wind to load-follow).

- In this paper we focus only on *local* demand-side activity - at the level of the distribution networks. However, future potential for demand-side services extends *right through the entire electricity system*. In time, different DSM products and services will offer different value to different parts of the electricity system in different time-scales : balancing ; wholesale markets ; capacity - as well as local network management. Moreover, demand-side price-visibility and price-discovery will in the end become important *across the full electricity value chain* to develop a better view of where value may be available to demand-side providers and to support *cost-efficient* demand-side participation in different parts of the electricity system.

- Flexible load at scale - electric heat and transport have yet to come forward at sufficient scale to offer local demand-side flexibility to offset renewable intermittency. If more flexible load does not become available, and intermittent generation continues to grow, then management of that intermittent generation will become increasingly costly, especially to the distribution networks.

- Storage – is likely to be *the* key enabler in allowing an efficient match between local generation output and local customer demand at scale. A major break-through in both storage technology and storage costs would first be needed to make local balancing at scale a reality.

In the long run, many of these factors will be associated with a fully functioning and cost-efficient GB demand-side – be that at the national level - or at a local level. In Paper 12, we will return to whether and how these factors may eventually come together .

Last, to stress that this paper *takes as a given* that **basic time-related tariffs and incentives,** and, in the long-run, **dynamic 'energy price-matching'** (assuming half-hourly settlement), can and will help to improve low-carbon and general electricity system cost-efficiency.

Sustainability First explored improvements in time- and price-related matching in retail tariffs to promote system cost-efficiency in detail in Paper 7[2].

Instead, this paper explores the far narrower issue ***of location and locational match as a further factor*** for improving the efficient match between local supply and local demand in the electricity system, and therefore in promoting *overall* system cost-efficiency. In the end, retail tariffs which are designed to promote low carbon and greater electricity system cost-efficiency will need to find ways to ***combine*** incentives which can reflect**: time-of-day and / or varying wholesale energy-prices - *plus* the costs and benefits of location.**

3 What more might be done to improve 'local-match' in the electricity system ?

Main findings and conclusions on how the electricity system treats 'local' and what more might be done to improve 'local-match' in the electricity system are as follows.

Market Actors

3.1 Suppliers

Suppliers are developing an active interest in developing electricity demand-side responses from their customers (near term : commercial advantage ; longer-term : imbalance ; capacity). However suppliers are at present largely 'neutral' on where their customers live and work – and may therefore have only a modest underlying commercial incentive to promote *local* demand-side activity. This situation may not change unless and/ or until there are stronger signals / commercial drivers for suppliers about specific *locational* benefits to the networks. And, even then, a supplier's primary commercial concern may most likely remain with balancing their contractual position in the wholesale markets overall, rather than seeking to encourage their customers to give demand-side support to the networks at particular places.

The paper discusses what some possible longer-term drivers might be to incentivise suppliers – both large & small – towards eventual greater interest in *local* management of supply and demand. For example, this could be via stronger locational signals to suppliers in network charges ; explicit 'benefit-sharing' between suppliers and the networks at particular places, or, in the long-run, with half-hourly settlement, new commercial opportunities for suppliers to seek to balance *local* supply and *local* demand.

[2] Including for small-scale PV. Sustainability First. GB Electricity Demand project. Paper 7 : 'Evolution of commercial arrangements for more active customer and consumer involvement in the electricity demand-side'. April 2013

3.2 **Distribution Networks**

There is clear value to the distribution networks in actively promoting peak-related 'firm' demand-side management *at particular locations* (constraint management, and, potentially, losses[3]). Networks need to find ways to promote local demand-side activity as a 'business-as-usual' tool by *clearly signalling* (1) those locations which are constrained and (2) the value associated with providing demand-side support at those locations.

Networks have limited experience of direct engagement with customers, but are starting to do this – *but on a largely ad hoc basis*. In the end, the networks will need to find more *consistent and systematic* ways to signal potential demand-side value *at particular locations* in the low voltage networks to interested providers, which are both visible and transparent. This will help interested providers (individuals, communities) at the local low voltage level to understand *whereabouts* local demand-side opportunities might be (see network charges below). Even so, there are significant obstacles for the networks to interface and work directly with smaller customers and communities to provide local demand-side services. Through LCNF and other activity, they are starting to explore ways to do this.

3.3 **Transmission Networks**

Transmission networks already flag locational 'inefficiency' via their charges with some success (viz TRIAD response). A household TRIAD (or critical peak pricing equivalent) will need half-hourly settlement – but for the long-run could serve *both* 'national' demand-side interests (major transmission bottlenecks) as well as *'local'* constraint management – so, perhaps offering some alignment at least between national and local network needs.

3.4 **System Operator**

The system operator needs more granular information about the location, output and despatchability of distributed generators, and, longer term, about demand-side actions at the 'regional' level, to avoid unnecessary balancing costs (and which fall to all customers). With eventual half-hourly settlement, a small-customer dynamic critical peak response (eg TRIAD-like) – would seem to align *both* 'national' and potentially 'local' demand-side needs of the system operator and both the transmission and distribution networks (balancing ; capacity problems; 'regional' and 'local' peak-related constraints).

[3] See footnote 74 on losses & DSR.

National, regional and local balancing - Cross-industry working groups are starting to discuss how balancing may work / interact in practice for the future at different 'levels' in the electricity system : national, regional, local. The system operator is responsible for *national* balancing of frequency and voltage in real-time. DNO licence duties (and associated revenues) require them to manage constraints and losses on their networks cost-efficiently. Via LCNF and RIIO ED1, distribution networks seem to be making rapid technical and commercial strides in development of automated network management & control systems to help them handle constraint and loss management more efficiently, and to avoid needless network investment. In future debates about a local DNO balancing role therefore, a sensible start-point would seem to be to clarify exactly what gaps, if any, exist in *current* distribution network duties, capabilities and available tool-kit in carrying out their core tasks of balancing network constraints and managing losses (see charges and incentives below). SGF Workstream 7 has a major study to look at this. The industry will wish to work together to develop a co-ordinated, consistent approach to local balancing – so that a cost-efficient and resilient outcome is delivered from a customer viewpoint.

3.5 **Smart Meters, Half Hourly Data, Settlement and Retail Tariffs**

As noted, there is a chronology associated with smart 'enablers' in development of a future demand-side – be that national or local. In the longer term, with wholesale electricity prices becoming more wind-driven, some tensions could arise between the basic commercial drivers faced by suppliers and distribution networks in terms of their interest in the demand-side – especially in terms of their possible interest in *local* demand-side responses.

Smart Meters – by *recording* electricity usage in half-hourly blocks, provide a basic step in unlocking demand-side activity – be that 'national' or 'place-specific'.

Half-hourly data - from smart meters for the distribution networks will support a better understanding of constraints and inefficiencies on their networks. However, networks will also need a capability to manage and make use of that information in a systematic way if they are to actively 'target' areas on their networks where *local* demand-side actions will bring value. There is likely to be a cost in taking DNO data management to a different level.

Basic static ToU tariffs enabled by smart meters : In the near-term, both suppliers and networks may have an interest in these being offered to customers because their commercial interests broadly align. But, for the longer-term, supplier interest in incentivising their customers to avoid peaks *day-in-day-out* may reduce somewhat once supplier risk-management increasingly relates to matching load with wind-driven wholesale prices (e.g. wholesale prices may be low at peak if it is windy). By contrast, peak avoidance is likely to remain *central* to cost-efficient management of the low voltage distribution networks – especially to manage network constraints which are shaped by peak-load.

Half Hourly Settlement – would eventually be needed if more targeted demand-side opportunities and developments are to be supported *via retail tariffs* – be that for suppliers and / or for the networks - because accurate matching *for billing purposes* of usage with demand-side actions at the level of the individual customer in any given half-hour would require half-hourly settlement. In the long-run this could unlock dynamic retail tariffs based around wind-twinning – and in which suppliers may perhaps develop a longer-term DSR interest. This supplier interest may or may not be location-specific - depending on whether dynamic DSR responses supported a better match for supplier wholesale contract positions. However, for the distribution networks, half-hourly settlement would better enable the networks to target *particular places* for developing *more local approaches to network charges* (but this seems a long way off – see distribution charges below).

3.6 How present Distribution charging frameworks treat the *local* costs and benefits which distributed generators and demand-side actions may bring.

In extremely general terms, the locational costs and benefits which relate to the place in which a distributed generator or a customer is connected to the network is treated by the distribution charging frameworks (both Connection and DUOS) in the following ways :

- **Locational *costs* are factored in for** : larger distributed generation ; larger loads (half-hourly & Load Profiles 5-8) and *existing* household and small business loads (Load Profiles 1-4). **Locational *costs* are not explicitly factored-in for** : smaller generators <3.68 kW ; additional or new loads installed by households and small business customers Load Profiles 1-4. (e.g. power showers, storage heaters, heat pumps, EV chargers).

- **Locational *benefits* are factored in for** : distributed generation : for larger DG via the 'embedded benefit' arrangements they have with a supplier via their power purchase agreement ; and, arguably, for smaller DG via the FIT 'deemed' export tariff (metered and unmetered spill). **Locational *benefits* are not *systematically* factored in for** : demand-side activity (be that for DSR, demand reduction or for storage). **However, benefits *are* available for local demand-side actions on the basis of *'ad hoc'* bilateral agreements with the networks for demand-side services.** Presently, such arrangements are available mainly to I&C customers (but some LCNF trials are looking to solve network constraints at particular locations by rewarding household demand-side activity).

3.7 Discussion of stronger demand-side signals in distribution charges

Part II of the paper discusses in detail whether more might be done by introducing greater cost-reflection, and possibly, sharper locational signals in distribution charges to help better

align the policy desire for more community and local energy with continued cost-efficient management of the electricity system – and if so how perhaps to set about this.

For small micro-generators and for the vast majority of customers, both Connection and DUOS charges (Distribution Use of System) presently convey a mostly unseen signal – and in any case a relatively weak one in practice - about the potential value which their demand-side actions might bring to the networks **at a particular place**. Ofgem, the network companies and suppliers will wish to consider how the development of greater cost-reflection, and, somewhat more controversially, explicit locational signals in network charges could evolve – both near and longer term. Three areas for further consideration are :

- **Separating out network charges -** what if any benefit there may be in splitting out network charges (DUOS plus TNUOS & BSUOS) from end-bills in support of more network visibility and transparency to help stimulate *local* demand-side activity ; what timing might be for any such move (eg post ED1, post smart meters and / or post-half-hourly settlement). In particular, it would be important to understand what potential impact splitting a retail customer's end-bill into its network and energy components may have in the long-run for the evolution of customer retail tariffs generally.

- **More cost-reflective approaches to certain components of distribution charges** - the pros and cons of adopting more cost-reflective approaches to distribution charging in the long-run (including the inter-play of both connection and DUOS charges). In particular, how greater cost-reflection could better support more cost-efficient network management at the local low-voltage level. **Potentially, this may include (1) adoption of connection charges for micro-generators and (2) an explicit capacity charge for small customers, to better reflect to them the costs associated with connecting major new loads (and which could help to support demand-side management retail tariffs).** Either of these steps may prove controversial and / or difficult to introduce in retrospect.

- **More location-specific distribution charges –** the paper notes how it would, in principle, for the longer-term to explore more radical approaches to locational network charges. For example : network charges which sought to *explicitly* differentiate between different places on the network to provide a far clearer signal to customers about the costs and benefits of their activities *at a particular place* (generators, customers). However, more explicit locational charges ('post-code' charges for example) may offer only uncertain benefit in terms of customers' ability to respond to a sharper price-signal at highly constrained network locations. Also, location-specific charges would unwind the present socialised approaches to cost-recovery across the low-voltage distribution networks, and, importantly, could potentially introduce unintended distributional impacts[4]. That said, with more locational approaches to network charges, options for

[4] See sections 4 & 14 consumer issues and cost-reflection.

dynamic local pricing (potentially *both* network and wholesale energy) and for local 'green' energy exchanges and trading platforms may start to open up. Any such developments are complex and would need very careful exploration - not least due to the potential for unintended distributional implications. More complex dynamic locational pricing options would most likely need half-hourly settlement – and so, potentially, are in any case some way off.

3.8 **Administrative silos and barriers**

A number of current administrative arrangements may need review 'in-the-round' - so that commercial opportunities and scope for local demand-side actions to offset / balance local supply may be more readily be identified - be that at the level of an individual household or a local community. This is particularly important if suppliers are to become more incentivised to promote local-balancing activity in a commercially 'holistic' way – including creating 'prosumer' customer profiles – be this the large integrated suppliers – or others under the Licence Lite arrangements. Three basic administrative obstacles noted in this paper include :

- **Present *commercial* separation at the level of the individual household** (or larger customer) **of arrangements for customer supply – and for FIT administration** (especially, but not only, for smaller PV).

- **Power Purchase Agreements (PPA) with distributed generators** – even though a supplier may have a PPA with a distributed generator, that supplier may nonetheless be commercially 'indifferent' in terms of linking output *from a particular PPA* to supply a *specific community or group of local customers.*

- **Challenges in data-protection and data-sharing arrangements among networks, suppliers and other interested third parties** regarding (1) the network location of micro-generation (especially smaller PV <3.68 kW) and low-carbon technologies (heat, EVs), and (2) for the networks to share micro-generation data notified to them by installers with third parties – and so to signal to others who may have an interest that demand-side activity may offer an economic benefit at a particular location.

3.9 **Local Demand-Side Incentives**

A comprehensive local 'solution-set' / tool-kit to promote 'local-matching' / self-balancing of low-carbon supply with flexible demand and / or low-cost storage is presently incomplete.

The evident success at a local level of *supply-side* low-carbon incentives, leaves low-carbon supply presently running some way 'ahead' of any meaningful offset from local demand-side development – at least until such time as electric heat and transport can offer a source of

flexible, automated DSR at scale. This low-carbon supply-side 'asymmetry', however transitional it may be, is starting to manifest itself as a cost-efficiency challenge for the distribution networks.

Despite the very many incentives available to support both installation of low-carbon technologies (FIT, Community FIT, RHI) and for energy efficiency (Green Deal, Community Green Deal, ECO) the paper *identifies a number of specific gaps for the demand-side across present incentive arrangements*. If such incentive 'gaps' were addressed, it may be possible to support better local matching of supply and demand in the near-term by encouraging simple household – or local – balancing / buffering and / or community level demand-side actions – to provide the potential for demand-side flexibility at scale. For example :

- **FIT for micro-generators (esp PV)** – is presently not tied to a requirement for some form of modest low-cost on-site storage (thermal or other) to avoid creating new network costs from unmetered spill.

- **Low cost thermal storage –** despite many available incentives (FIT, RHI, Green Deal, Community GD, ECO) no incentive is directed ***specifically*** at simple forms of low-cost thermal storage (e.g re-wire / simple adaptation of household hot water tanks ; electric storage heaters[5]), notwithstanding that such thermal measures could certainly encourage simple within-household - or local - balancing / buffering of supply and demand at the very local level. Low cost thermal storage is generally over-looked as a near-term solution to support local matching with PV and wind (i.e. prior to availability of flexible load at scale from electrification of heat and transport – and we will return to this topic in Paper 11.

- **Explore linking receipt of subsidy for heat pumps or electric vehicles to a requirement for a smart meter** – (plus, at the very least, an *offer* of a Time of Use retail tariff) to over-come **potential cluster problems**.

- **Modest 'set-up' funding for neighbourhood or community-level demand-side and / or local balancing projects.** Part IV of this paper provides a detailed account of the practical and organisational reality which communities face in engaging with the electricity demand-side, based on six GB electricity demand-side case studies. Community and local groups who may wish to be *active on the demand-side* – perhaps *instead of / or as well as* on community generation may struggle to readily find 'early-stage' funds to help them 'mesh together' local generation projects with demand-side actions and / or modest thermal storage. *Many of the incentives presently available to communities are focused on the 'supply-side'.* Also, access to LCNF funds is very largely company-led. Local groups, however active and committed they are, will find

[5] Not classed as 'renewable' for RHI purposes.

themselves struggling to 'mesh' together demand-side schemes which might either be designed (1) to alleviate local network constraint and / or offset losses by peak-reduction and / or (2) to balance low-carbon supply with specific local demand-side actions. Access to some modest upfront funds – explicitly for early-stage set-up of *community electricity demand-side schemes at the very local level* - may help to address at least some of the organisational and financing barriers which such community-led initiatives may face. The forthcoming Community Energy Strategy may wish to consider the merit of 'set-up' funding for *local demand-side* schemes which could balance local generation (but not just) – and how this might best be supported [6].

4. Consumer issues : cost reflection and local supply

4.1 Consumer issues : greater cost-reflection in network charges

This paper touches only briefly on some of the potential customer and consumer issues which may arise with a more *local* demand-side. In particular, we will return in Paper 12 to the topic of what greater cost-reflection, both in retail energy tariffs and in network charges could mean for end-consumers [7].

Future evolution of distribution charges is an important consumer issue. Any move towards greater cost-reflection in network charges – designed to develop stronger and more cost-efficient *local* demand-side signals[8] – may also have the potential for adverse customer impacts - especially if these were to be *directly payable by end-customers*.

In particular, and as noted, *explicitly locational* price signals may be controversial – for example, in regions, areas or places where individual customers, groups of customers, or particular communities may be *unable* to respond with flexible demand-side actions. A network may be constrained for historic reasons - or because of new distributed generation or new load connecting leading to insufficient spare network capacity. Given that moving elsewhere is not a serious option, possible impacts on different groups of end-customers which could result from reflecting sharper locational signals in network charges to end-

[6] For example, perhaps a via 'benefit sharing' arrangement, linked to potential savings for the local electricity distribution network.

[7] In Paper 8, we looked in detail at household consumer issues likely to arise from development of the electricity demand-side, including consumer issues relating to development of smarter retail markets beyond the relative short-term of the Retail Market Review. Ofgem has just published a consultation on Consumer Empowerment and Protection in smarter markets (16 December 2013).

[8] Discussed in section 14

customers – and in particular any potential distributional impacts – would need to be properly understood.

From a customer viewpoint, some possible issues to consider in terms of any move to greater cost-reflection in network charges *direct to end customers* include :

- Connection or capacity charges : retrospective introduction of such charges (for PV, electric heat, EVs) may be seen as 'unfair'.

- More explicitly *locational* network charges : may not necessarily produce a good locational 'match' between constrained parts of the network and customers who are in practice able to respond with flexible demand-side actions (and could well penalise customers at constrained locations who are *unable* to be flexible).

- Possible distributional impacts of more 'extreme' locational - or even 'post-code' - low-voltage network charges.

4.2 **Consumer issues : local supply**

Whilst there will always be a need for bulk power flows, local-level demand response and matching seems a generally desirable goal to support low carbon and improve overall electricity system cost efficiency where this is also generally beneficial to consumers.

However, in drafting this paper, a number of wider considerations were raised with us regarding general consumer issues in seeking to develop a better local 'match' between local energy and local demand :

- It is presently hard to understand in a systematic way what financial or commercial value local matching can bring – be that from the viewpoint of a household, local neighbourhood or wider community level – or indeed for a network at a particular local feeder, substation or grid supply point.

- Local network re-inforcement may well be seen as a less risky commercial proposition for assured delivery of resilient networks - both from a network perspective and in the end for the generality of customers.

- Distributional impacts *at a regional level* could result if customers become increasingly reliant on *local* energy supplies : for example if *local* demand had strong 'peak' characteristics – but local generation was largely intermittent – then consumers might well be better served by their supplier making wholesale energy purchases in a nationally interconnected and traded electricity system.

- From a non-discrimination stance, interaction between DNOs and certain groups of consumers - rather than others – may need further consideration. Similarly, interaction with third-party providers, including local authorities, social landlords etc.

- Customers not able (for whatever reason) to actively participate in *local* energy markets, may over time be faced with paying for a higher proportion of the overall fixed costs of the electricity system. In the long-run, success at scale in local matching of supply and demand could potentially leave a diminishing customer base from which to recover the continuing fixed costs of providing the transmission networks and the higher voltage distribution networks and national-level balancing.

- There is likely to be a need for suppliers to *demonstrate* / *validate* the match of local demand with local supply, to justify any possible discount or rebate on network charges which may be available to them (or their 'local' customers) for their demand-side contribution. Otherwise, without validation that supply was locally consumed, other suppliers (or other customer groups) may face higher fixed network and balancing costs than warranted (for transmission, distribution and for national-level system balancing). For a successful local demand-side, validation of *local* supply may therefore be needed *in addition to* half-hourly export metering and half-hourly settlement.

- The reward for savings achieved from local demand-side efficiency between the network and the customer (or their supplier) will need to be transparent and clear to all parties. Under the price control efficiency incentive, the networks are strongly incentivised, by being able to retain up to 70% of any savings within a price control period. This suggests that the basis on which any demand-side savings would be rewarded and shared between the network, suppliers and their customers or community groups, would need to be both fair and clear.

- Low-cost forms of storage could deliver a cost-efficient 'buffer' between local supply and local demand – whether this 'buffering capability' be at the level of an individual household - or at the level of a distribution network. In section 12 on incentives, we note a 'gap' in present demand-side incentives in terms of support for modest thermal storage solutions (e.g. adaptation / re-wire of hot water cylinders, new-style storage heaters[9]) and in Paper 11 we will return to the question of how far options for household-level thermal storage are presently somewhat overlooked as a low-cost storage solution capable of being delivered at scale. Significant break-throughs in storage technology and cost (battery or thermal), capable of 'matching' local PV or wind output with local customer demand, have the potential to revolutionise approaches to local energy supply and the development of local energy markets.

[9] Water cylinders offer a good year-round match for PV and wind. Storage heaters have a poor match in absorbing excess power in the summer months.

5 Lessons from community studies

Part IV of this paper considers six local / community electricity demand-side case studies. It concludes with a general discussion of practical lessons from a literature review and from the case-studies, likely to be helpful to market actors or others with an interest in developing local or community electricity demand-side initiatives – especially those with an interest in engaging local groups and communities in provision of *firm* demand-side services.

Of the six case studies, three were island / remote communities, so considerations arise as to how 'replicable' some of the lessons may be.

Our headline findings below are divided between potential benefits and challenges for community-based electricity demand-side action.

5.1 Benefits and opportunities for community-based electricity demand-side action

- **Communities who already have an interest in energy efficiency projects are easier to engage. However most of those groups are presently not necessarily actively engaging on demand-side projects with suppliers or DNOs.** For market actors, developing successful partnerships with community groups can offer a significant benefit in being able to work with 'trusted third parties'. Pre-existing groups are more likely to prove a sustainable and successful channel for local engagement, rather than a group either brought together or created by external actors to deliver a specific demand-side project.

- **Local balancing/matching of supply and demand may make it easier to engage people in local DSM as they can directly see/feel whether renewables will be working on a particular day.** For example, the very small community on Eigg knew when it was sunny or when the wind was blowing – which – together with a highly visible traffic light system - acted as a spur to use energy at appropriate times.

- **Working with communities can transform the role of the DNO.** Engaging with a local community, to explain the potential shared-benefit of avoiding new investment (e.g. by use of new commercial and / or technical solutions (e.g interruptible contracts, automated network management) has the potential to change the current nature of a distribution business, including basic business relations and local partnerships.

- **Working with community groups, and giving them a sense of ownership, is challenging but seems essential to secure action on the community scale.** Demand-side approaches which are 'community-led' may offer greater demand-side potential due to greater 'buy-in'.

- **Supporting community groups can enhance their effectiveness.** The added benefit likely to arise for a community group on a demand-side project which involves an 'informed' partner such as an energy supplier or a distribution network is material (good access to information, advice etc) and may help deliver success.

- **There may be more scope for local balancing projects with isolated communities.** Small communities in remote locations - with both high levels of renewables and network constraints (Scotland, south-west of England) – may offer most potential for local, community-level balancing projects, at least initially.

5.2 Challenges for local community balancing or local demand reduction projects

- **Lack of expertise within community groups means – on the whole - that communities are unlikely to initiate demand-side projects on their own.** Even where communities are engaged and committed, the effort necessary, know-how and energy to initiate and see-through even a modest demand-side project is considerable.

- **There is no incentive for communities to engage with demand side activity on a community level and no provision of information as to where demand side activity would be best placed.** Most communities do not have access to data to show them how their energy is used or where demand might most usefully be reduced. Even with smart meters, it is not clear how readily such 'local-level' *community* data will come to the fore. DNOs are producing maps to identify where there is potential for new renewable connections. Similar initiatives and maps to indicate where networks are especially constrained – which would flag where community level demand-side engagement may have a value to the DNO – would be of help.

- **Community groups that already have an interest in energy might not be located in a part of the network in which there would be value in localised balancing or demand reduction.** Electricity demand-side projects (both demand reduction and DSR) are likely to be more effective where there is congruence of an interested community and an electricity system efficiency need. Currently, a DNO may have a constrained part of a network – or a community may wish to get involved – but the two may have no means to connect (or reason).

- **DNOs are not visible to the average community.** For example, work by IPSOS Mori for Ofgem found a very low level of awareness among most end-customers of the role of the distribution networks.

- **Working with third parties, and relying on consumer action, can be a challenge for DNOs who need a guaranteed solution to their network constraints.** Delivery of 'firm' demand-side management solutions, unless automated, (including local-level

balancing) is a riskier proposition for a DNO than 'fit and forget' approaches to new network investment.

- **There is no 'one size fits all' approach in terms of matching local supply with local demand.** First, DNOs have different constraint problems at different locations (and which can evolve or change over time). Second, community organisations, their interest-levels and commitment to reducing their carbon footprint or their energy supply will significantly vary.

- **It is unclear whether the case studies we looked at which were reliant on active community behaviour change would be either persistent or replicable.** Some of our case studies were time-limited, and, on at least one, momentum seemed to falter. Only the Isle of Eigg (a very small island example - faced with a very high-cost interconnection as the alternative) demonstrated continuing action on demand reduction.

- **Providing value for communities/ households who engage in DSM, based on avoided investment, is possible but it is unclear what the reward-level would need to be to encourage action.** In our case-studies, rewards given to communities for succeeding in their demand-side actions were distinct from a transparent calculation of value derived from savings from deferred or avoided network investment. Only on project (the NINES project in Shetland) is attempting to link the customer incentive for installing storage heaters to the likely network investment cost savings.

- **Energy companies, Ofgem and others need to learn the emerging thematic lessons from the many new electricity demand-side projects that are underway.** The case-studies we have explored were chosen (in part) because project material was available to us. Far more case-study material will become available over the next two years which will contain valuable thematic lessons. In particular, on the realism of how the cost-savings which networks seek at particular locations can be matched with the capability of local neighbourhoods or groups to deliver demand-side reduction or DSR on a sustained basis. It will also help to indicate how suppliers and other third parties such as local authorities can themselves be identified to help and support targeted demand-side action.

6 Possible next steps for Ofgem, DECC, distribution networks and market actors in improving 'local-match' in the electricity system

There are a great many initiatives by Ofgem, by market actors and others already in hand - and some are noted in sections 16 & 17 of this paper. Many of these initiatives will serve to support greater locational efficiency in the networks over the ED1 period to 2023 and beyond, including helping to facilitate a better match of local supply with local demand.

Below we pull out some possible next-steps from this paper for others to consider and which may start to help in detailed consideration of how to unlock more *local* demand-side value and activity.

6.1 **Ofgem – possible next steps**

- **Continued priority focus on development of smarter markets** - smart meters, half-hourly settlement - which are both key enablers for more local-level demand-side actions. **Smart Grid Forum work streams 6 & 7** – also getting to grips with technical and commercial requirements for cost-efficient local supply and demand.

- **Provide a clearer view on what specific administrative, regulatory and other steps** are needed to enable *local* generators to sell their output to *local* consumers and / or to community buildings (Licence Lite may help – does not fully resolve – especially for very small-scale generation).

- **Clear communication to non-specialists on how developments in technical regulation can be expected to address network 'unregulated' disturbance** (**from new loads and micro-generators)** – rules, industry codes, equipment standards.

- **Clarify triggers and / or time-table post-ED1 to developing more cost-reflective signals in distribution charges to loads in Load Profile Class 1-4 - and PV < 3.68 kW – and consider suitable approaches -** may be of particular relevance in the case of PV clusters [10].

- **Continue to encourage DNOs to engage in neighbourhood and community-level demand-side initiatives via RIIO ED1 and network innovation competitions (**where these might bring an efficiency benefit to the electricity system), including perhaps allowing some set-up funds or a benefit-sharing arrangement to encourage local

[10] See section 14 for discussion of (1) possible connection charges for micro-generators <3.68 kW and (2) possible capacity charges to smaller customers.

partnerships at particularly constrained parts of the network (eg with local authorities, local or community groups).

- **Consider how future network innovation competitions might perhaps work better for active communities** – e.g. if a community wished to take the lead in solving specific network constraints – eg 'auctions' for community-led projects at particular network locations.

- **Consider in more detail the longer-term pros and cons (especially from a consumer viewpoint) of more radical approaches to network charging :** eg location-specific / post-code charges ; *local* green power exchange / trading platform etc.

- **Ensure that trial-outcomes on demand-side management and local / community energy -** where these demonstrate both cost-efficiency and replicability - are integrated into 'business-as-usual' across all of the networks in a strategic, consistent and systematic way. For example, to consider systematic adaptations to DCUSA to enable, for example, a DUOS rebate for communities or individuals who provide firm demand-side benefits to the network at a particular location / substation where this is constrained.

- **Communicate a longer term view on developments for distribution charges** – including with respect to : greater visibility and transparency of network charges ; potential evolution towards more cost-reflection ; cost-allocations between connection and DUOS etc.

6.2 DECC – possible next steps

- **Consider general consumer impacts (pros and cons) of more community and / or locally oriented approaches to energy supply** – for example, the possible distributional impacts for some customer groups ; possible resilience issues.

- **Community Energy Strategy** – may wish to explore 'set-up' funding for community-level *'local-balancing'* schemes (eg perhaps as a gate-way to accessing other funding sources) to produce more 'rounded' local community energy schemes which can 'self-balance' in terms of local electricity system efficiency.

- **Explore incentives for local modest thermal storage** – for household or local-level 'buffering' of wind or PV - and which is presently not incentivised (so, for re-wire / adaptation of hot water cylinders, storage heaters).

- **Explore linking the receipt of a subsidy either for heat pumps or electric vehicles to a requirement for a smart meter** – (plus, at the very least, an *offer* of a Time of Use tariff) to over-come potential cluster problems.

- **Explore, with Ofgem, how to address present administrative 'silos'** - which may inhibit supplier commercial interest in local demand-side action. Includes : FIT administration and customer supply **;** PPA agreements & local supply ; data protection and data sharing across actors on location of low-carbon technologies.

6.3 Distribution Networks and Market Actors – possible next steps

- **At constrained network locations** be open to extending present bi-lateral demand-side approaches to I&C customers to communities (and even to smaller customers).

- **Pro-action in terms of signalling best places / hot-spots on the networks for demand-side actions** (so not just about distributed generators) **– including at community-level or for third party intermediary action** (so, local authority, aggregator).

- **Support for demand-side actors in understanding whether the most cost efficient demand-side solutions at a particular location might best be served by** distributed generation (despatchable or 'must-run'), demand-side management and / or overall demand reduction – and find ways to communicate this.

- **Longer term, explore with Ofgem how to formally acknowledge collective / community-level demand-side actions in distribution charges (eg formalise possible DUOS rebates or possibly, demand-side equivalent of 'embedded benefits'.).**

- **Consider the merit of support for a new electricity sector Community Unit –** a one-stop advisory shop - to provide early advice and generalised help to interested communities and local groups – and to help bridge the 'silos' these groups may find in dealing with networks, suppliers and the system operator - if they are considering small-scale electricity generation or demand side actions in their area.

- **Continue to develop industry-wide understanding of 'boundary interface issues' in transparent ways to the benefit of customers –** via cross-industry working groups on interactions between market actors of demand-side value and services and where 'location' may sit in that mix.

Paper 10

The Electricity Demand-Side and Local Energy : how does the electricity system treat 'local' ?

Part II

What location and the local demand-side mean to market actors

Part II takes a detailed look at underlying commercial and regulatory areas to be tackled before a *local* GB demand-side is likely to be realised at scale. Part II discusses what 'local' presently means to different market actors : to suppliers, the transmission networks, system operator, and the distribution networks. It considers how today's centralised electricity industry commercial frameworks, charges and administrative arrangements treat local generators and end-customers - *in terms of their physical impacts and location*. It discusses how for the future some underlying 'industry plumbing' – in particular approaches to distribution charging - may need to adapt to facilitate more *local* demand-side activity, and / or *local matching of supply and demand* (assuming this is both cost-efficient and generally beneficial to consumers). Part II concludes with a brief discussion of some high-level consumer issues in a more 'localised' electricity world, including fairness issues.

Part II - What location and the local demand-side mean to market actors and consumers

7. **'Local' low-carbon and electricity system efficiency.**

8. **How industry network and balancing charges treat location.**

9. **Suppliers - what local customers mean to them.**

10 **Transmission Networks - what generator and customer location mean for them.**

11 **System Operator – what distributed generation & customer location mean for them**

12 **Distribution Networks – impacts of low carbon technologies.**

12.1 **Low-carbon incentives and the distribution networks.**
12.2 **Physical impacts (benefits and costs) of : low-carbon generators, new electrical loads and demand-side actions.**

13 **Distribution Charges – treatment of location.**

14 **Distribution Charges – how might these become more supportive of the local demand-side ?**

15 **Consumer Issues : Cost reflection & local supply**

7 ‘Local’ low-carbon and electricity system efficiency

7.1 Responding to the changing reality of distributed generation and active demand

In a world of distributed low-carbon generation, and an active demand-side, the role of location - and ‘local’ - in terms of electricity system efficiency - and associated charges – has a new relevance. Achieving a good *local* match between supply and demand is likely to become *far more relevant than today* for delivery of a cost-efficient electricity system overall.

The government is actively promoting Community Energy (June 2013 Call for Evidence ; Community FIT ; Heat Strategy) and Ofgem is also considering how to stimulate local and community-level energy initiatives within the current regulatory and price control frameworks (measures in RIIO-ED1; Ofgem’s September 2013 workshop).

Increased small-scale generation is combining with a fast-growing interest in, and new technical developments relating to, electricity demand-side management (including options for storage and automated network management). These developments, as well as the potential for rapid improvement in automated management of customer load, make the prospect of achieving a better *local* match between supply and demand an increasingly realistic, attractive and potentially cost-efficient proposition.

Locational efficiency is already a significant technical and cost consideration for market actors – mostly for the networks.

In general terms, a good locational match between supply and demand should (1) help to reduce the costs of managing the physical constraints and bottlenecks in the electricity networks (albeit to some degree inevitable) and (2) reduce losses. In this sense, good locational match should help to defer or save on building unnecessary new network capacity or reinforcement, and/or save on other costly measures or actions which may be needed to overcome network constraints in order to match supply and demand. This is so for both distribution – and transmission.

Growing volumes of small-scale ‘non-despatchable’ low-carbon generation, and prospective clusters of new electrical load (heat, transport) are likely to start having an increasing impact on our networks. In the first instance, these local efficiency considerations *are chiefly matters for the distribution networks* – and somewhat less so for the transmission networks or the system operator. In due course, this may change should the volumes of distributed low carbon generation - and levels of demand-side activity - become such, that their physical impacts start to create significant new costs in the wider electricity system – either for balancing (system operator) or for transmission networks (peak management, unpredictable flows at the

distribution / transmission boundary)), and / or potentially for suppliers (unpredictable / unforeseen patterns of usage leading to imbalance at particular locations). But these wider impacts may be some way off.

For the future, commercial frameworks for supply and for the demand-sides, if they are to support electricity system efficiency **will need to work together more closely at a local level**, **by meshing together *both* local generation *and* demand-side actions in a complementary and efficient way. This is especially important in terms of incentivising local balancing where this is cost-efficient – be that 'self-balancing' at the level of an individual household - or more general local balancing at a wider neighbourhood, substation or community level.**

7.2 Relevance of 'local' for electricity system efficiency

Almost every electricity customer is connected to the low voltage distribution network. Most electricity customers – from large industrial and commercial customers (I&C) to individual households – cannot exercise 'choice' on where they physically connect to the electricity system. This is also true for groups of customers – be that at street, neighbourhood- or community-level.

Generators may have more choice where they connect – but in practice, many other physical and economic considerations come into play. Larger generators may be able to exercise some choice on location, but many trade-offs are involved[11]. Smaller distributed generators have less choice[12]. The smallest generators, especially household micro-generators - have no choice on location. Generally, community-led generation schemes also have little choice on where they locate.

Over many years, with the aim of promoting greater technical and economic efficiency in the electricity system, industry commercial frameworks and the associated charging arrangements have become increasingly cost-reflective.

Such cost-reflection also extends *to the treatment of location* of both generation and demand (to some extent at least) : the aim being, given the geographic match of supply and demand across the electricity system, to reflect the costs associated with providing, maintaining and developing secure and reliable networks[13]. These network charging frameworks were largely devised for today's era of larger generation and for passive demand. In practice, the most overt locational charges are directed at large commercial generators, to encourage them to

[11] Fuel, available site, associated connection costs, planning etc

[12] Hence some of the distribution network trials with non-firm connection agreements

[13] For example, locational treatment especially in transmission charges .The transmission networks for multi-directional bulk power flows ; the distribution networks for one-way radial flows at decreasing voltage levels, down to the end customer.

connect to the transmission networks at places nearer to centres of demand – and to reflect the costs of providing bulk-power transport for 'passive' customers.

At the local distribution level, commercial frameworks and charges have increasingly sought to 'recognise' both the costs and the benefits which 'local' generation may bring to the electricity system. But, as noted, even where charges incorporate some location-specific signals, much generation – and most customers – cannot in reality readily respond.

The following sections therefore consider in detail :

- The costs and benefits which low-carbon distributed generation and demand-side management – DSR, electricity demand reduction (EDR), local storage – might bring, in terms of *location*, to the overall economic efficiency of the electricity system – and how small local actors are *currently* treated in the electricity system.

- How far present signals in network charges to small low carbon generators and to the demand-side are generally supportive of *local* responses – in particular for local matching of local supply and local demand where these may add to electricity system efficiency.

- If local matching is not supported, why not ? (i.e. what are the key barriers from a supplier, distribution network, customer and local community perspective ?).

- What changes in industry administrative arrangements and / or in approaches to distribution charges might help to support a more active local demand-side than today ?

8 How industry network and balancing charges 'recognise' location

Locational impacts and efficiency are already recognised and promoted in industry network charges - for both generation and demand. The charges are designed to reflect the knock-on investment costs for the networks from constraint management via :

- **Connection charges** - (both T&D) – whereby the costs which may arise from connecting a new generator or demand customer *at a particular place* on the network are 'shared', at least to some extent ;

- **Use of system charges** - (TNUOS (p/kW & p/kWh)) & DUOS (p/kWh) which incorporate cost-recovery for fixed costs of network provision (and which take some account of location).

- **A capacity element** - incorporated in use of system charges (p/kW - T&D) which takes account of either the export capacity (generator) or maximum import capacity (large customer) at their location.

- **Treatment of losses in TNUOS, BSUOS & DNUOS** - (a geographic (so locational) adjustment to reflect the cost of losses across the system (p/kWh).

Essentially, the larger the generator - or the customer[14] - the stronger the locational signal they face as a result of these different charges *in combination*.

Approaches to reflecting 'locational efficiency' to network users vary somewhat between TNUOS, DUOS and BSUOS charges [15] :

- **Transmission charges** - (TNUOS) are *adjusted by zone* depending on where suppliers' customers are located. Broadly customer demand charges are generally twice as high in the south as in the north (both I&C and smaller customers). Transmission generator charges are also lower in the south and higher in the north. TNUOS charges include an adjustment for losses[16].

- **Balancing charges** (BSUOS) are adjusted for losses – so incorporate a locational element to some extent.

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[14] In particular 100kW+ half-hourly settled customers

[15] **TNUOS** – Transmission Use of System ; **BSUOS** – Balancing Services Use of System ; **DUOS** – Distribution Use of System charges.

[16] Transmission connection charges also reflect the cost of connecting at a particular location to large generators.

- **Distribution charges**[17] – (DUOS) vary both *between* distribution networks[18] and *also* by voltage of connection. They are also adjusted for losses, so incorporate a locational element to some extent. EV charges also give customers an explicit locational signal. HV and LV DUOS charges do *not* give customers connected at those voltages an equivalent locational signal. For larger customers, (but not small customers), that is done by the connection charge.

As noted in section 7, more cost-reflection in network charges to suppliers (and, possibly in the long-run to end-customers) – which may or may not imply sharper *locational* signals – is likely to become more relevant as a part of the network tool-kit for managing peak-related constraints and losses (especially as demand and / or peak demand increases) in the future.

[17] EV - Extra high voltage ; HV – High voltage ; LV – Low voltage.

[18] In part due to network characteristics which reflect location – urban, rural etc – as well as asset age etc.

9 Suppliers - what 'local' customers mean to them

9.1 Supplier neutrality on 'local'

Suppliers are the *main interface with each customer* connected to the low-voltage network.

Suppliers may well have a *general* interest in exploring their customer interest in demand-side management - yet *where a customer lives or works presently seems to have little bearing on a supplier's basic commercial relationship with their customers*. From a local electricity demand-side perspective, suppliers seem at best 'neutral' with respect to *whereabouts* on a network a particular customer may sit. Commercial drivers for suppliers to offer *local supply* and / or promote *location-specific* demand-side activity among their non-half hourly customers are weak. This is so for :

- The 29 million supply customers (small, large – wherever they live or work).
- For the power purchase arrangements (PPAs) suppliers may have with smaller distributed generators (and therefore for 'embedded benefit' arrangements) .
- The 350,000-plus micro-generators, for whom suppliers administer the quarterly FIT payments.

This relative neutrality among suppliers *about their customer location*, prompts questions as to what factors may stand in the way of their becoming commercially more interested either in *local* supply and / or in *local* demand-side development at scale. Some issues seem to be :

- A supplier is required to have a *separate* commercial and administrative interface with their *supply* customers on the one hand – and with those customers with whom they also have a FIT administration or a PPA arrangement on the other - *even where these arrangements are with the same individual customer, community or business*. In local demand-side terms, this 'ring-fence' seems to make it quite hard for a supplier to treat a customer *as a single 'pro-sumer'* e.g for it to make *commercial sense* to a supplier to offer a 'PV-matching tariff' to one of their supply customers who also has a PV installation on the roof[19]. In practice, some larger suppliers may not even *know* that their own supply customer has a PV unit on their roof. Equally, from a customer demand-side perspective, should a customer *wish* to be treated by their supplier as a single 'pro-sumer' in this way, it is also not easy to overcome

[19] and for whom the supplier may or may not administer the FIT

these administrative 'silos' to access a single 'holistic' demand-side offer or proposition from their supplier[20].

- A supplier 'owns' the direct basic customer relationship - and supplier involvement is therefore important in principle for DSR development – be that 'national-level' or for 'local-level' demand-side activity. However, there may be little incentive for a supplier to lead (or even to become directly involved), where a distribution network (or other third party) may be looking to put in place a bi-lateral *local* demand-side arrangement in place with householders or a local community. A main aim of the CLNR LCNF project (Northern Power Grid & British Gas) is to explore how a supplier and a network *can work together* to develop successful commercial approaches to incentivise local demand-side activity. Even so, it will be big step for networks to develop *direct relationships at scale* with individual smaller customers – although DNO and / or aggregator activity could perhaps be targeted at constrained places on the network[21].

- Network use of system charges (TNUOS, BSUOS, DUOS) – are mostly simply passed by suppliers to their smaller customers unseen[22]. The networks presently *depend upon the supplier* to convey any general locational signal to non-half hourly metered end-customers (in so far as these signals exist in present network charging arrangements) - including about whether demand-side response may have any value in a particular zone or region of the country. But from a supplier perspective, even where locational differentials do exist within the present network charges which they pay (transmission, distribution), there seems no incentive to pass-on these signals in a more explicit way to their smaller end-customers.

- The present arrangements by which DUOS charges are payable by suppliers, arguably leaves a supplier somewhat disinterested in promoting demand-side actions by a

[20] Despite the many administrative obstacles, some smaller suppliers are actively developing business models which look to create PV / 'prosumer' customer profiles.

[21] Where a distribution network (or other third-party) may be looking to put a *bilateral* demand-side arrangement in place with household customers (or individuals in a particular community), it is presently not possible for settlement purposes for smaller customers to have more than one supplier. Under the Balancing & Settlement Code, it is feasible for a half-hourly settled I&C customer to have more than one supplier *for settlement purposes*. In principle, with the advent of universal half-hourly settlement, such a **multiple supplier arrangement for settlement purposes** would be feasible at a household customer level – allowing customers and / or communities to have one settlement arrangement for their supply / import - and another for their demand-side activity (i.e. potentially having different arrangements for each activity). (Email exchange with Elexon. November 2013).

[22] See later.

particular local group or community (total kWh volumes are allocated to each supplier in every half-hour at the level of each DNO region)[23]. Arguably, this relative indifference may change if suppliers are faced with ToU charges for low voltage customers (see section 14) – or, in the long-run, with universal half-hourly settlement of every customer.

- For the future, in a market where wholesale prices may be wind-driven for increasing periods of time, the respective *commercial* interests in demand-side management of the networks and suppliers could increasingly diverge – *especially with respect to peak periods (weekday evening, morning) in places where the distribution networks* ***are constrained***.

    - Networks will still seek *mostly location-specific and peak-related demand-side responses to manage network constraints.*

    - Suppliers may wish to help manage their contractual positions in the wholesale markets through demand-side management measures (i.e wind-twinning tariffs). Supplier and network commercial interests *may continue to coincide at peak periods when wholesale prices are also high* (ie when no- or low-wind coincides with peak). But, *when it is windy at peak periods* (so, when wholesale prices may be lower) *supplier and network interests may diverge* ***in places where the distribution network is constrained*** : suppliers may wish to incentivise electricity-use in those periods (including for storage) ; whereas networks at particularly constrained locations *may wish to reduce customer load through demand-side management responses.* In places with plenty of network headroom, there would be no need from either a network or supplier viewpoint to constrain customer load or wind-output at peak periods.

    - Available value from DSR savings : with wholesale electricity costs representing around half the end-bill - compared with ~20% for the network component. A paper by Poyry[24] found that customers – *unless at a very constrained network location* - were more likely to obtain higher rewards in offering their demand-side services to actors *other than the distribution networks* (e.g. to the supplier in a wind-led world, to the system operator for Balancing) – rather than for *local* demand-side services.

[23] 'Super Customer' volume allocation arrangements at the Grid Supply Point Group for each distribution region - based on a supplier's aggregate customer numbers and for each half-hour, the eight 'standardised' customer consumption profiles (Load Profiles 1-8).

[24] Poyry. Paper for ENWL & National Grid. 2012.

So, in sum, both now, and possibly more so in the future, commercial signals to suppliers to develop local demand-side actions are weak, with seemingly little incentive for suppliers to promote customer demand-side actions *at a particular place***.**

Other reasons which may inhibit present supplier interest in DSM (national and local).

Poor commercial alignment of supplier and network interests and / or lack of a supplier business case are not the only barriers which may presently inhibit suppliers in offering more opportunities to smaller customers for demand-side engagement – *be that for demand-side participation within the national system – or in terms of demand-side services to the 'local' system.* Depending on the nature of the demand-side activity which suppliers or the networks may seek, three other steps will be key for greater engagement of smaller customers.

Smart meters – and appropriate billing software. Needed for any supplier - or for a network - to offer basic static time-of-use retail tariff to customers. **Basic static time-of-use retail tariffs align well with local network needs** for :

- Peak avoidance (constraint management);
- Potentially, local PV-matching (i.e lower price at mid-day).
- Simple thermal storage (storage heaters, hot water cylinders, heat pumps with storage)

However, basic static ToU tariffs may work *less well* for matching wind.

Half-hourly meter-data from smart meters – would be necessary for distribution networks to give *suppliers* stronger *locational* signals via DUOS.

Half-hourly settlement – would be needed to give a stronger locational signal *to an individual end-customer*. It is also likely to be needed to offer 'dynamic' non-static retail tariffs. So, for suppliers to create wind-twinning retail tariffs ; for the networks to develop more cost-reflective & granular network tariffs - be that for particular customer groups – and / or at particular places on the network (for example to deliver household dynamic and / or critical peak retail tariffs). Half hourly settlement may still be some way off however (2020's).

9.2 Network charges & supplier view of 'local'

Suppliers pay transmission and distribution charges to the networks for moving their customers' power and to the system operator for balancing.

Network charges presently represent around 20 % of the end-price of electricity to consumers. (Transmission – 4% ; Distribution - 16%)[25].

Suppliers are 'billed' for their network charges in the settlement system - on a basis which is standardised on a per customer basis. Suppliers recover these costs from their end-customers via their bills.

As noted in section 8, TNUOS, BSUS and DUOS each *incorporate some form of broad locational differential / adjustment* – including for losses[26]. Billing to suppliers for their network charges therefore incorporates a geographic / locational element, in so far as the settlement system generates a bill to suppliers at the level of each Grid Supply Point Group (which mirrors the footprint of each distribution network). It is not known how this broadly 'regional' approach to supplier billing impacts a supplier's view of customer location – but in terms of any broad locational differential in network costs and charges it is perhaps fair to assume that (1) these locational differentials are generally not presently viewed as material and (2) that each supplier will choose how they pass any locational differential which may exist, to their end-customers.

As noted above, it seems likely that the socialised arrangements for cost-recovery of the cross-industry network charges – TNUOS, BSUOS & DUOS - including how these reflect *location* - may to some degree re-inforce supplier 'neutrality' to customer location.

Visibility of network charges to customers - Two key points arise about the visibility of network charges to customers – including any locational incentive these charges may contain.

- **100kW half-hourly settled customers** – **and half-hourly metered distributed generators** – TNUOS, DUOS & BSUOS charges are likely to be directly visible to most (but not all) of these customers – including the zonal component of their TNUOS charge (so, ~117,000 customers, less than 0.5% of all electricity

[25] Ofgem Factsheet – Jan 2013.

[26] The sum payable by suppliers for TNUOS, BSUOS & DUOS is calculated within the Settlement process according to the supplier's 'volume allocation' at the Grid Supply Point Group for every customer whose meter is registered with the Settlement System. The Settlement System factors location into these charges by adjustments by Transmission Zone in TNUOS – and also adjusts for losses for TNUOS, DUOS and BSUOS.

customers)[27]. Suppliers often provide a 'notification' service to their half-hourly I&C customers to help them avoid the TRIAD-related element of their TNUOS charge, **especially for customers in the south of the country – whose transmission charges are likely to be higher and so represent a more material saving where avoided.**

- **29 million Load Profile 1-8 customers – and small generators -** network charges are not directly visible to the vast majority of customers. From a purely *locational* view-point, making present network charges *more* visible to end-customers would not of itself become a demand-side incentive – although at 20% of the total end-bill these charges are non-trivial. There may anyway be separate transparency or other reasons in favour of eventually making these charges more visible to the end-customer.

Importantly, there seems to be a developing view that the present structure of DUOS charges for non-half hourly customers fails to offer suppliers a sufficiently strong signal / incentive to take steps to promote more DSR among those smaller customers[28].

9.3 For suppliers, what is the commercial benefit of matching local supply and demand ?

Being a *local* supplier may arguably offer some potential for 'market advantage', for example by supplying a particular local community or being associated with a local generator.

The main benefit in being a local supplier would seem mainly to relate to potential savings on (1) negotiated power purchase agreements with local distributed generators and (2) on some element of saving in *load-related* network and balancing costs (but not all).

In practice however, most local or community-level suppliers would still depend on interconnection to the wider electricity system for basic security reasons – and so suppliers would still incur some network costs (unless supply was offered to customers on a wholly islanded or full 'private-wire' basis).

[27] In practice, will depend upon the billing arrangement with their supplier or utility broker – not every half-hourly metered customer 'sees' their network charges separated out in their bills.

[28] See section 14 on distribution charges and present DCUSA / Distribution Charging Methodology Group discussions to reform DUOS with measures such as ToU charges at low voltage, capacity charges for small customers etc.

In principle, a local supplier might expect to negotiate some discount on network and balancing charges – e.g. the equivalent of 'embedded benefits' for any *local* supply, local generation and local demand-side contribution they may agree to deliver (so, possibly, some potential for avoided TNUOS, BSUOS, EHV and HV DUOS). However, any discount may need half-hourly settlement plus appropriate verification that the supply was indeed 'local' if other suppliers (and indeed customers in general) were to accept that any such discount for a supplier (and / or a particular group of local customers) was justified.

The size of any such network savings is hard to know (likely to be well below the 20% end-cost to the bill of the networks, unless at a very constrained location). Also, the benefit of any savings from local supply, could be expected to be 'shared' with local customers and / or community groups as a core element of their 'local' retail offer. How any such rebates might impact retail tariffs for neighbouring customers who perhaps *do not* take supply from that local supplier is also hard to know.

9.4 **Large suppliers – commercial interest in local supply and demand-side ?**

As already noted, a number of factors seem to leave large suppliers *commercially* relatively neutral as to the *location* of their customers – large or small. This may also partly result from the substantial separation between their generation and supply arms ; also, regulatory push has encouraged larger suppliers to seek customers outside their historic 'incumbent' areas, geographic economies notwithstanding.

A group of suppliers, has been considering how suppliers might use demand-side management in the future[29]. Suppliers would seem to have two core aims:

- **Supplier balancing** – to achieve a better match of their *own* contract position and reduce imbalance risks and charges. It is unclear how far that may have a *locational* dimension, given a national approach to balancing.

- **Locational Network Balancing** – supplier activates DSR *in support of* locational / geographic / regional network needs.

[29] Supplier draft Strawman. Shared with Smart Grid Forum Workstream 6. (v2 July 2013)

9.5 **Small Suppliers – commercial interest in local supply and demand-side ?**

Smaller suppliers may well have a stronger commercial interest in the location of their customers - especially if they have close links with a particular renewable generator and / or if they wish to supply a particular community. This is already evident from the business models and retail activity of some small suppliers.

Small suppliers - Licence Lite – The Licence Lite arrangements are designed to support development of small new entrant suppliers[30].

A small local distributed generator, interested in matching / balancing their output with local demand - either for commercial or for community reasons - and wishing to sell *direct to local customers* (be that to their neighbours or to a community building), may presently:

- Need to become a Licence Lite supplier in their own right (which implies a certain scale - and which many small distributed and micro-generators may not be in a position to do)

  or perhaps rather more likely

- Sell their output under a power purchase agreement to a supplier willing to buy it. That could be direct to a large supplier - or to Licence Lite supplier[31].

The Licence Lite arrangements could in principle support 'local balancing' and 'local-matching' at the small-scale or neighbourhood level to some degree. Some early issues to consider may however be that :

- Potential Licence Lite suppliers – local authorities, community companies or others could offer a strong geographic / local focus to their 'customer offer' – which may better facilitate 'local' matching of supply and demand. Notwithstanding their 'lighter' responsibilities however, Licence Lite suppliers may still face complexity and financial risk in seeking to make local-balancing succeed.

[30] Ofgem slides. Community Energy Workshop. 4 September 2013.

[31] The Greater London Authority is understood to be considering becoming a Licence Lite supplier. This would then enable them to be in a position to buy and 'sell-on' the output of small distributed generators within London area. 'Smart City' – Intelligent energy integration for London's decentralised energy projects. Report for the GLA by AECOM, Poyry and WIPRO. July 2012

- Transaction costs - associated with local-matching / balancing of supply and demand may be non-trivial - *even with Licence Lite*[32].

- Unmetered spill - Unless or until there was universal export metering, *unmetered* spill from smaller PV installations (<30 kWe) would continue[33]. Being a Licence Lite supplier may therefore in itself not necessarily overcome all of the administrative 'silos' noted earlier, and which inhibit treatment of the smallest low voltage customers (or groups of customers) as 'prosumers'.

9.6 What might motivate suppliers to support greater 'local-matching' between their customers and local generation ?

For the future, especially after half-hourly settlement - what might motivate a supplier to take a more active interest in *local* balancing for their own customers with distributed generation *at a particular location* ? Some possible drivers might be :

- **If customers' end bills were to be made more transparent in the future – and network charges explicitly split out in end-customers' bills.** For the sake of better transparency, it may be feasible to identify 'nominal' Transmission and Distribution charges in today's end-bills – including (possibly) to indicate the impact of location in these charges. In principle, this may be feasible ahead of smart meters and ahead of half-hourly settlement – but would have implications for billing software and associated billing costs.

  For the vast majority of customers connected to the low voltage distribution networks , aside from improving transparency and visibility, there is perhaps little point at present in splitting out network charges in this way (i.e. ahead of smart meters and ahead of half-hourly data and / or half-hourly settlement). **One long-run argument in favour however may be that greater visibility of network charges could in turn start to point to particular areas where locational charges are higher and so help to stimulate interest in demand-side activity – be that from local generation or from demand-side actions**.

- **If suppliers find themselves with *unexpected* 'physical imbalance' in a particular region or at a particular grid supply point** eg due perhaps to significant unmetered spill

[32] See Sustainability First Paper 5 discussion about understanding the full costs, risks and benefits of household-level demand response.

[33] Smart meters *may* address the problem of unmetered spill – but it is still not clear how the export register (single register only) in the SMETS 2 meter will in practice relate to that customer's PV unit.

from very small scale distributed generation (PV, say) - or if there was very active demand-side activity at a particular location (perhaps due to a demand-side contract with a network or an aggregator) – suppliers may increasingly look to their customers in those regions / areas to 'self-balance'.

- **If suppliers were strongly incentivised by the networks – perhaps via avoided or discounted network charges (avoided TNUOS, BSUOS, avoided EV DUOS, avoided losses) - to encourage their customers to reduce peak demand *at particular locations*.** For example, if there was sufficient value on offer for suppliers from a 'benefit sharing' arrangement between themselves and the transmission and / or distribution networks to encourage suppliers' customers to load-shift / reduce peak load *at particular locations*. Somewhat challengingly for the networks, and as noted in 9.1 above, suppliers in the long-run may find themselves with *less* incentive to encourage their customers to avoid consuming electricity at peak periods when it is also windy at peak times (morning, winter evening).

- **Once suppliers have access to far more granular and accurate data (once smart meters) – both about their own customers' electricity usage and the *location* of those customers - and the *location* of micro-generation clusters – suppliers may become more *commercially* interested than today in *local* balancing approaches.**

- **However, greater commercial interest from suppliers in *local* supply, may need some present administrative 'ring-fences' to be dismantled first –** as these may presently inhibit suppliers from being more commercially pro-active in encouraging more self-balancing and 'buffering' at the local level. For example :

    - **The administrative separation of the Supplier FIT arrangements for micro-generators - and the arrangements under which suppliers provide *the same customer* with an electricity supply**[34] **–** so that commercially a *supplier* could obtain the cost-efficiency benefit of incentivising 'self-balancing' actions via ToU tariffs *at an individual customer level* (eg by offering thermal storage (storage heaters, hot water).

    - **Power Purchase Agreements (PPA) with distributed generators** – even though a supplier may have a PPA with a distributed generator, that supplier may nonetheless be commercially 'indifferent' to linking output from a particular PPA to supply a *specific community or group of local customers.*

    - **Data protection and information sharing arrangements -** which may inhibit basic information-sharing among market actors about the location of PV

[34] See Sustainability First Paper 7 for an extended discussion of these issues.

clusters or other low carbon technologies (heat pumps, EVs) and which would enable suppliers and the networks to consider where greatest value might be obtained from demand-side activity.

Suppliers - distributed generators and local demand 'matching'.

Suppliers may own - or part-own - renewable generation assets which are distribution-connected, (but there may be a substantial separation from their supply arm).[35] Suppliers may also have Power Purchase Agreements with smaller distributed generators (but which they do not own) - either to fulfill their Renewables Obligation (as now) or in future under the EMR FIT CfD arrangements.

Presently, however imbalance is calculated and charged at the transmission / distribution intersection (with a socialised adjustment for losses). Suppliers are therefore not greatly incentivised at present to match local generation output with local demand.

In the future this could change : once intermittent generation drives wholesale prices for significant periods[36] and half-hourly settlement and sharper imbalance prices[37] force greater accuracy upon suppliers in how they match their contracted wholesale position with their customers' usage. Smart meters and half-hourly settlement will also enable development of better 'price-matching' with wind and / or PV. For cost-management reasons therefore, suppliers may perhaps look with greater interest than now towards 'local-balancing' and 'local matching' among their own customers.

Suppliers also have a *separate administrative* role in relation to distributed generators – but neither of these roles seem to give the supplier a particularly active interest in the *location* of that distributed generator :

- **Suppliers who provide FIT Administration services to distributed generators** - are indifferent to the *location* of the distributed generators for whom they administer the FIT payments[38] because there seems to be some adjustment for losses in their volume allocation at settlement. (And FIT Administration arrangements are separate from whether a supplier has a power purchase agreement with that distributed generator).

- **Embedded generator credits** - Historically, non-licensed generators connected into the distribution networks (<50 MW) are acknowledged to help *suppliers* avoid TNUOS and BSUOS costs, plus the costs of losses as allocated to suppliers in settlement (so, a locational element). The benefit therefore accrues in the first instance to suppliers. The distributed generator in their Power Purchase Agreement with a supplier then negotiates for that benefit to be credited to them[39].

[35] A generation licence would be required for DG assets over 50 MW.

[36] Which the supplier may or may not own

[37] Cash-out Review

[38] See Sustainability First Paper 7 for a detailed discussion of the mis-match arising from the total ring-fence of suppliers' roles in terms of (1) FIT Administration and (2) supplying their customers.

[39] Distributed generators in England & Wales connected at 132kV presently receive embedded benefits – but in Scotland they do not. An industry-led Embedded Benefits Group is looking at this. Also, Element Energy explain (p.38) explain that Generator TNUOS charges are presently 15% locational – and 85% 'residual'. Discussion has taken place on whether distributed generation is therefore potentially 'overpaid' where it expects

10 Transmission Networks – what generator and customer location mean to them.

Transmission networks - physical impacts of location : For the transmission networks, the key physical challenge in terms of location is the prevailing north-south flow of bulk power transfers : much generation is located in the north and large centres of demand tend to be in the south and south-east. The physical location of both generation and demand therefore remains a major factor in terms of new or avoided transmission investment and cost-efficient constraint management. Managed connection arrangements (non-firm) allow connection of more northern generation ahead of transmission re-inforcement.

How transmission charges treat location : transmission charges (TNUOS) are zonal, designed to reflect the costs associated with location of both generation and demand on the Transmission Network and so convey a signal to large transmission-connected generators and to suppliers (and, indirectly, to very large half-hourly metered and settled customers) about the costs of providing the transmission network.

Impact of transmission charges on location of generation and demand :

- **Transmission-connected generation** : TNUOS sends a locational signal to generators in the north (in broad terms higher generator TNUOS charges in the north). Under Project Transmit[40] transmission charges will remain locational but will somewhat dampen the present locational signal for low-carbon generators in the north – in recognition that low-carbon is a priority consideration for policy delivery.

- **Demand** : TNUOS *does* send a locational message about demand *to suppliers* and to large I&C customers : in broad terms, higher TNUOS demand charges are payable in zones in the south. Active load reduction on the three highest evening peaks of each winter – especially in the south - has a *physical* benefit to the transmission network in terms of helping to delay peak-related investment (security-standard related investment (SQSS)). The desire to avoid the *locational* element of TNUOS charges successfully drives this active large customer 'TRIAD' response (avoided winter peak). Apparently, this effect is *most notable in the south*

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to receive a 100 per cent TNUOS discount. Ofgem has argued that the embedded TNUOS benefit should instead reflect the 15% locational element.

[40] Ofgem is in the final stages of project TransmiT which is a major review of the structure of National Grid transmission charges. Serious Code Review CMP213.

where TNUOS charges are highest – evidence that a *locational* critical peak pricing message can succeed.

Visibility to end-customers of locational signal in TNUOS : Transmission-connected generators pay transmission charges and 'see' the locational element in their charge. For customers, TNUOS charges are payable *by suppliers* via the settlement arrangements – and are not visible to most end-customers, (other than half-hourly I&C customers)[41].

- **Large half-hourly settled I&C customers** are likely to be aware of their transmission charges – because suppliers generally pass these through - including customer awareness that these may vary according to location – hence the apparent southern bias of the TRIAD response.

- **Smaller customers** : TNUOS charges are not visible to them despite there being a locational / zonal element to the relevant charge. And even if this charge could be made more visible, these customers would still need half-hourly metering and half-hourly settlement before they could offer dynamic critical peak pricing – in effect a household TRIAD (and which similarly could be expected to have more value in the south).

[41] Around three-quarters of annual TNUOS charges(~£1.7 bn in 2011) are levied via demand customers.

- For an I&C customer.the zonal charge is on a £/kW basis (for example, with over a two-fold differential between the highest (£37.32 /kW – south west) and lowest (£15.42 /kW - Northern Scotland). These zonal differentials seem to incentivise southern I&C customers to avoid their charges more. (There is also a non-locational 'residual' element (£22.83p/kW) in 2012-13, regardless of zone).
- The zonal non half-hourly customer charge (including households) is on a p/kWh basis (Monday to Friday 16.00h – 19.00h). For household customers, TNUOS is just over twice as much for a customer in the south 5.25 p/ kWh – London as in the north 2.11 p/kWh (Northern Scotland). For non-half hourly customers, the sums relating to TNUOS are likely to amount to a relatively small element of their end bill (TNUOS = ~4%). (National Grid Indicative TNUOS Demand Tariffs – 'Status Quo'. September 2013)

11 System Operator - what distributed generator & customer location mean to them

11.1 System operator and location

System operator - physical impacts of location : As noted, location of generation and demand is already factored into approaches to transmission network constraint management. In today's world, physical location of generation and demand is therefore *currently* less critical to the system operator in terms of their task of constant balancing supply and demand on the national system (to manage frequency, voltage in operational timescales). In practice, location *does* matter for balancing where a particular problem at a particular location arises. In the future, with significantly higher volumes of unknown or unpredictable / intermittent distributed generation, there could be more by way of *regional* impacts in terms of requirements for balancing the national system, but this point is understood to be some way off (although National Grid is alert to how this may change in the future (and, could change relatively quickly : for example, if very high volumes of PV grow in a particular region – e.g. the south-west)[42].

How Balancing Services recognise location : payments to those who offer national-level Balancing Services to the system operator, (including payments to distributed generators and those able to offer demand turn-down) do *not* include a locational element. However, in practice certain balancing service providers will be selected due to their location, especially if there is a particular problem at a particular location (eg a broken-down generator)[43].

Balancing Services cost-recovery : costs which the system operator incurs in balancing the system are recoverable via BSUOS - Balancing Services Use of System Charges (BSUOS) payable by larger generators and by suppliers[44]. BSUOS charges are

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[42] UK Solar PV Strategy Part 1: Roadmap to a Brighter Future . DECC. October 2013.

[43] So, in this sense, a locational benefit is given to individual actors at a particular location through their 'usage' payments – but there is no differentiation by location in payments for 'availability'. In discussion, National Grid felt that there is presently little need to differentiate the Balancing market by location, although for the future, this could change.

The new DSBR Scheme (Demand-Side Balancing Reserve (DSBR) & Supplemental Balancing Reserve. Final Proposals Consultation. National Grid. 11 October 2013) designed to support system balancing against anticipated narrowing plant margins mid-decade notes that DSBR 'units' may on occasion be despatched according to location.

[44] Balancing and Settlement Code signatories. Ofgem consultation November 2013 'minded to' document indicating a continued 50 : 50 split for adjustment of BSUOS payments at the Grid Supply Point group between generation and supply.

adjusted for losses at each grid supply point group, and in this sense take some account of location. Balancing charges have no visibility for end-users.

11.2 System operator - better information about distributed generation and demand.

National Grid told us that they do not as yet have access to sufficient granular information about distributed generation and demand. Below the Grid Supply Point interface with the distribution networks, information available to both the transmission networks and to the system operator about distributed generation, and also about the make-up of customer load in any half-hour remains limited. In particular, lack of knowledge about the installed capacity of distributed generation, its load-factor and output patterns (eg wind, PV) and also, to some extent at least, its location, may risk additional balancing costs[45].

The system operator is keen to continue to work with the DNOs, DECC and Ofgem to improve their knowledge of distributed generation. In particular, data on DG capacity (including micro-generation) ; whether 'despatchable' or 'must-run' (wind, PV, anaerobic digestion) and its general location. National Grid's UK Future Energy Scenarios[46], outlines work they have in hand to improve their knowledge of both distributed generation and of demand patterns across all sectors of the economy.

Nevertheless, for the time-being, *location* remains a somewhat secondary consideration from a system operator perspective. Should Government projections of 10-20 GW of PV, or, a very great deal more distribution-connected wind, become a reality, this may change. In the long-run, voltage and reactive power management issues – could perhaps arise (e.g should there be very significant clusters of PV, in, say the south-west).

Earlier Sustainability First Papers [47] also highlighted the very significant lack of up-to-date and detailed data on Distributed Generation as well as the significant gaps in knowledge of – plus poor coordination of - the data that exists for small PV in particular – and the knock-on problems this could potentially create right through the electricity

[45] Due to holding higher balancing reserves to handle a higher level of 'forecast error'.

[46] UK Future Energy Scenarios. UK gas and electricity transmission. National Grid. July 2013.

[47] Sustainability First. GB Electricity Demand Project. Paper 6 : 'What demand-side services does Distributed Generation bring to the electricity system. January 2013.

Sustainability First. GB Electricity Demand Project Paper 7 : Evolution of commercial arrangements for more active customer and consumer involvement in the electricity demand-side and Annexes 2-4. May 2013.

system, for the distribution networks, the transmission networks and the system operator alike.

In particular, unless and until there is much better knowledge of *both* local low carbon supply and local customer demand at particular locations below the grid supply point, there may be little real understanding of the potential for self-balancing at particular locations.

11.3 Balancing : a national, regional and 'local' activity ?

Looking to the future, a main impact of the development of distributed generation may mean that real-time balancing may no longer remain just a national activity – but become a regional – and – the focus of this paper – potentially also a very local-level activity.

- **National level** - Balancing presently remains a *national-level* activity – e.g the NETA / BETTA wholesale electricity market was designed to encourage bilateral forward contracting for self-balancing by generators and suppliers of supply and demand at a national level, with residual real-time national-level balancing (chiefly real-time frequency & voltage management) ensured by the system operator. Assuming an unconstrained import export capability, their task is to match generation and demand at the national level at all times.

- **Regional level** - Discussion is beginning via various industry groups about a need to understand for the future what need there may be for more active balancing than now, in effect at a *regional* level – in the event that flows across the transmission / distribution boundary (the Grid Supply Point Group) – should become two-way. For the future, this could happen, for example potentially in the south-west, at periods of low customer demand (e.g. in summer) when it was also very windy, sunny, or both.

- **Local level** – Smart grid developments point to a future where *local* active network management and balancing become far more important than today in terms of overall electricity system efficiency at the low voltage level. Several LCNF projects have a strong focus on this area (Automated Network Management & Control etc). DNOs already have duties, incentives and revenue streams for efficient management of their networks, including for management of constraints and losses. A DNO balances their network by ensuring that circuits are not over-loaded : either by making operational interventions so that maximum loadings do not exceed network capacity ; or, by investing in new network capability. Increasingly, 'smart' grid management by DNO's may - or

may not - mean a need to consider a formal or new balancing responsibility for the distribution networks (so, akin to the system operator). A debate about whether DNOs need a new or additional licence duty for balancing with some kind of appropriate efficiency incentive, perhaps must start from a clear understanding of how far existing licence duties presently may fall short of the tools which distribution networks will need. The industry will wish to work together to develop a co-ordinated, consistent approach to local balancing – so that a cost-efficient and resilient outcome is delivered from a customer viewpoint[48].

[48] see section 15 on consumer issues

Balancing, Transmission & Distribution Network Interfaces

There are a number of current initiatives to explore - and begin to bridge - some of the technical and commercial interfaces between market actors - at different points in the value chain. This includes exploring how *national* balancing activity can and does relate to a future demand-side at particular locations of both the transmission and distribution networks – and how this may evolve in the future.

For example :

- **System Operator and Electricity Networks – DSR Shared Services Group**. A collaboration between the system operator, distribution and transmission networks (co-ordinated by the Energy Networks Association), considering a 'shared-service' model (or models) for I&C and SME demand-side products and services. Issues under discussion include, for example : the relative 'value' of demand-side actions to different market actors ; which market actor(s) across the full supply chain might take 'precedence' in terms of their technical needs for demand-side services ; the nature of different demand-side 'products' - and the revenue streams which may encourage these to come forward ; the capability and / or willingness of demand-side players to provide demand-side services. Report expected end-February 2014.

- **Work to consider information requirements across the value chain** – and improving on presently available data about distributed generation at a national system and regional level.

- **Treatment of future 'boundary flows' (possibly bi-directional) at the interface between transmission and distribution**. (see next box)

It is not clear how far these present initiatives are actively considering promotion of 'self-balancing' as a goal *at the very local level*.

Studies considering future boundary flows between transmission and distribution (1)

Smart Grid Forum Workstream 7 – is looking in depth at the technical development of the smart grid and the 2030 Distribution Network to ensure technical viability, and will also consider eventual impacts for the roles and responsibilities of the distribution networks.

'The Cross Electricity Networks Project' is a working group of the Electricity Networks Strategy Group (ENSG), set up in October 2012 to conduct a 'gap analysis' of the interactions between the electricity networks[49]. The stated long term vision is to 'achieve coordination across different elements of the electricity system, during planning, development and operation, to reduce system and security of supply risk, minimise costs, and ensure timely connections'. With respect to the intersect between the transmission and distribution networks, the report discusses, inter al, industry co-ordination and potential 'gaps'. Two areas of relevance to this paper discussed in the Cross Electricity Networks Project paper are :

- **Coordination of Strategic Decisions** : (inter al) insufficient interaction to provide a coordinated and optimised approach to voltage control across various levels of the network (eg reactive compensation contribution) ; lack of a process to optimise the interconnect points between transmission and distribution.

- **Information Exchange and Knowledge Sharing** : interactions needed to improve visibility, *via better information* exchange between DNOs, TOs, SO and Developers around information of embedded generation eg location, size, generation cycle (The Grid Code Panel and Distribution Code Panel are also addressing these information gaps).

The ENSG paper does not seem to make explicit reference to consideration of consistency of arrangements for network charging, including for example consistency of approaches in treatment of location and 'local'

[49] Final Report for Cross Electricity Networks Project. November 2013.

Studies considering future boundary flows between transmission and distribution (2) 'Community Energy Systems' – Smart Energy Special Interest Group. TSB KTN[50].

Two largely technical studies supported by the Technology Strategy Board on Community Energy Systems (CES) have started to explore whether, in the long-run, the transmission – distribution interface may be better-served, either from a technical or from an economic stand-point in a smart-grid world by 'islanded' community energy systems, which are very largely capable of self-balancing – be that at the very local LV level, or, at a higher level of distribution voltage.

The paper notes that a community energy scheme can take many different forms and sizes, ranging from a small group of buildings to whole towns. They foresee that in the next 10-15 years, from a practical perspective, community energy schemes are most likely to be geographic entities – but perhaps 'virtual' in the longer term. The paper uses the following definition of a CES : 'An energy generation, distribution and storage system (where required) involving local community ownership and participation for purposes of creating collective benefits for the community, including reduced bills, revenue generation, investment opportunity and community regeneration'.

The paper explores whether, community energy schemes could eventually make as much as a 10-15% contribution to the UK's electricity needs - and, if so, what physical / and or commercial limitations might arise at those kinds of level[51]. From a purely technical perspective, the paper finds that development of community energy schemes making a 10-15% electricity contribution could be feasible. However, the paper also concludes that a full comparison is needed of alternative innovative energy strategies : namely, the relative costs, benefits and overall economic efficiency of decentralised versus centralised energy systems, and on which they propose further work – and, not least, that the cost and viability implications for the national transmission network, if relegated to an eventual largely 'back-up' role.

[50] The Role of Community Energy Systems in the UK Resilient Energy Supply. A Study by the Smart Energy Special Interest Group (SE SIG) for the Information & Communications Technology Knowledge Transfer Group of the Technology Strategy Board. April 2013.

Also, SE SIG Community Energy Systems Foresighting Project. Final Report. July 2012.

[51] The first SE SIG paper (July 2012) suggested that community energy schemes might in time contribute up to 10-15% of final UK electricity generation. The second paper has therefore undertaken a more detailed look at the technical and commercial implications of that initial 10-15% estimate.

A 10-15% total contribution from community energy schemes implies an increase of *six to nine times* the generating capacity currently expected to be brought forward by 2020 by the FIT and Renewables Obligation. For example, 10-15% from community energy schemes would imply ~4.77 million micro-generation installations.

12 Distribution Networks – impact of low carbon technologies

Section 12 looks at the impact on the distribution networks of :

- The incentive arrangements for low carbon and the demand-side.
- Physical impacts (benefits and costs) of : distributed generation, new electrical loads and the electricity demand-side.

12.1 Low carbon incentives – impact on the distribution networks

The success of the incentives and subsidies to foster low carbon generation (RO, FIT) – and in the future, the incentives for low-carbon load too (RHI (heat pumps) ; EV grants) – mean that new and additional / physical impacts arise – especially at constrained locations on the distribution networks. **For the smallest non-despatchable micro-generators and for new loads (HP & EV) connecting at low voltage, these local impacts have yet to be fully factored within and / or accommodated by industry technical rules, in the way that network charges are set – and factored into associated cost-recovery arrangements.**

At present these physical impacts are not uniformly material on the distribution networks. They are very largely confined to *particular locations / clusters* on the distribution networks. The impacts arise largely from :

- The nature of the present incentives, which *in commercial terms* for much low-carbon distributed generation are effectively 'must-run' / non-despatchable – arguably creating network inefficiency from high volumes of unmetered spill[52] ;
- The volumes at which these technologies are starting to connect *at particular locations* and
- The potential *cumulative impact* of their intermittent and / or less predictable operation[53].

[52] E.g. small PV <30kWe

[53] We looked at these issues in some detail in respect of smaller PV in Paper 7 'Evolution of commercial arrangements for more active customer and consumer involvement in the electricity demand-side. April 2013' and PV Annex 3.

Community FIT – larger schemes 5-10 MW. Introduction of the Community-Level FIT may support some new community-level schemes[54] . However, in itself the Community FIT does not directly address the question of the 'incentive-gap' we have identified (next para), in terms of stimulating *complementary* demand-side activity to offer local-matching / balancing – and so addressing some of the costs and other impacts which may arise from non-despatchable or intermittent generation.

12.2 Local demand-side - lack of explicit incentives and / or revenue streams

Local flexible demand-side response could help redress some of the physical 'must-run' impacts of the local 'supply-side' low carbon technologies – and therefore the costs. This is especially so for offering flexible demand-side measures which may be capable of supporting 'local-matching' or 'self-balancing' to buffer low-carbon supply (wind / PV) – be this at the level of an individual home or building ; a cluster or street ; a neighbourhood ; or a local community.

But, by contrast to the low-carbon 'supply-side', there seem to be relatively few explicit instruments, incentives and / or revenue streams explicitly designed to promote system flexibility via ***local*** demand-side measures – i.e. demand-side management / response, overall electricity reduction, modest small-scale thermal storage (heat, hot-water) ***at particular network locations***.

Half-hourly settled I&C load (but not just) *does* increasingly have access to a number of revenue streams for providing flexible demand-side response – but, with some limited exceptions, these schemes seem very largely designed to address *national system-level needs* (e.g. STOR; DSBR from 2014 ; capacity mechanism in 2017; Electricity Demand Reduction pilot; capital grants for pilots for large-scale storage (generally batteries). None of the above incentives seem likely to readily incentivise demand-side activity ***at a particular location***[55].

Existing incentives for energy efficiency (Green Deal, ECO) are largely designed to improve insulation and heating efficiency. Notably, they do *not* support particular low-cost forms of thermal storage (storage heaters ; electrically-heated hot-water) *which could, for example, potentially support 'self-balancing' / buffering within an individual PV household.*

[54] Ofgem E-Serve Slides. Ofgem & DECC Community Energy Workshop. 4 September 2013. FIT Order 2012. PV <250 kW for : Education Providers ; Community Interest Company, Co-operative Society, Community Benefit Society - with less than 50 employees.

[55] Other than storage. See next page for discussion of the development of some bi-lateral I&C demand-side schemes at particular locations on the distribution networks.

Nor are these incentives likely to be able to stimulate demand response by *households* in the near term – whether at a national or a local level – unless or until there are both smart meters and, probably, half-hourly settlement for validation purposes.

Nor, in contrast to the new Community FIT, do there seem to be *explicit community-level incentives* which would allow *for collective demand-side actions at a neighbourhood or community-level* which could serve to, say, alleviate a particular network constraint, or, offset the output of a local wind generator by installing low-cost local thermal storage.

In practice, there seems to be an under-lying general assumption that a customer's desire for lower electricity bills will *provide a sufficient incentive in itself* to drive flexible demand-side actions and responses – be that for overall electricity demand-reduction, shifting load to lower cost times of day (assuming smart meters and time-related tariffs), and / or, 'storing' low-priced electricity in low-cost forms of thermal storage (storage heaters, hot-water) and using it at higher-cost times of day. This assumption that the benefits of demand-response will provide its own incentive through savings on the bill, fails to recognise that demand response at the household and small customer level may well require upfront investment and expenditure[56]. For example, installation of storage to 'buffer' PV or wind – even basic storage such as storage heaters or hot-water cylinders - entails up-front spend.

Nevertheless, and despite many seeming obstacles, some stimuli and incentives for *local* flexible demand-side responses - based on the concept of *sharing the benefit of the prospective cost-savings at particular locations* - are beginning to evolve due to :

- **Distribution network bi-lateral arrangements with I&C customers for demand-interruption** for purposes of pre- & post-fault management (e.g. ENWL Capacity to Customers I&C demand-side pilot (C2C)); Customer Network-Led Revolution project).

- **Distribution network social obligations under RIIO ED1** – and other ED1 incentives & TOTEX - should enable DNOs to become more creative in seeking demand-side solutions, including for permanent electricity demand reduction. Examples include : SEPD SAVE LCNF project (Solent Achieving Value from Efficiency) ; new UKPN LCNF project 'Vulnerable Customers and Energy Efficiency' (November 2013). ENWL - Stockport.

[56] For a detailed discussion of the likely up-front and transaction costs associated with household demand response see Sustainability First. GB Electricity Demand Project Paper 8 : 'Electricity demand and household consumer issues'. July 2013.

12.3 Conclusion on demand-side incentives and the distribution networks

A comprehensive local 'solution-set' / tool-kit *to promote 'local matching' / self-balancing of low-carbon supply with flexible demand and / or low-cost storage* - is presently incomplete.

To date, drivers for low-carbon - geared to promote and to develop local renewable generation, heat pumps and EVs – seem presently to be running somewhat 'ahead' of drivers and available incentives for developing an active *local* demand-side. In turn, this is leading to new physical challenges in terms of cost-efficiency, particularly in the distribution networks.

In effect, *local* demand-side tools are not yet readily available *at scale* to 'balance' / offset some of the physical / cost-impacts of local distributed generation (nor those which may arise from clusters of heat pumps or EV charging). Ad hoc bi-lateral demand-side agreements are available from distribution networks for I&C customers at some locations. However, there is presently no formal recognition in distribution or wider industry commercial frameworks and charges, of the potential for *local demand-side efficiency benefits* to alleviate local network constraints - especially from the very localised impacts of small scale low-carbon generators and possible clusters of new electric loads.

However, the impediments to local matching of supply and local demand are not just about the availability of incentives. As already noted, there are also other obstacles at the distribution level, including:

- A need for smart meters & half-hourly data – and eventual half hourly settlement
- Distribution network history - no direct relationship with end-users – nor the right organisational 'infrastructure' readily to so do.
- A likely need for potential automated control of loads such as hot-water cylinders, new-style storage heaters, HPs and EVs.
- Lack of explicit signals / incentives in DUOS *to suppliers* to encourage DSR among their non-half hourly customers[57].
- *Other administrative issues and silos* - which act as a barrier to local matching of low-carbon supply and demand[58].

[57] And this unlikely to change unless and until half-hourly settlement.

[58] E.g As already noted, data sharing arrangements between actors ; separation of FIT administration and customer supply arrangements at the level of an individual customer, making it very hard for a supplier to treat their PV customers as a single 'pro-sumer' with an appropriate PV-related tariff ie. as a *single combined commercial entity*. See Sustainability First Paper 7 Annex 3 for an extensive discussion of these issues.

12.4 Physical impacts (local benefits and costs) of : low-carbon distributed generators, new electrical loads, and flexible demand-side actions

Following on from the above discussion of the impact of low-carbon incentives upon the distribution networks, the remainder of section 12 looks in a high-level and non-technical way, at some of the main *physical* impacts – both in terms of their associated local benefits and likely costs – to arise for the distribution networks from :

- Low-carbon (non-despatchable) distributed generators
- New electrical loads (HPs, EVs)
- Demand-side actions.

Some of these impacts may in the long-run manifest themselves system-wide – in particular with distributed wind or PV *at scale*. In practice, many of these impacts are most likely in the first instance at the local distribution level.

12.5 **Distribution network - codes and technical rules**

Physical impacts of both distributed generation and demand on the distribution networks (and potentially on the wider electricity system) – are controlled through technical and operational codes and rules, designed to ensure the safe, secure, reliable and efficient operation of the electricity system[59].

To better accommodate the *physical* impacts of low carbon technologies and new loads on the network and the wider electricity system, some distribution-level agreements, technical codes, rules and standards are presently being revised by industry technical working groups (eg to deal with the commercial 'must-run' nature of PV, including spill ; harmonics of large non-compliant heat pumps etc).

Present codes and technical rules ensure that (1) distributed generators over a 3.68 kW threshold and (2) commercial load[60] - meet the explicit technical requirements of connecting to the distribution network. These are for the most part factored into industry charging arrangements and therefore the costs and benefits of their physical or technical impact on the electricity system and the networks are largely internalised by them – including to some extent with respect to location.

[59] Annex 1

[60] Load over 100kW – plus larger commercial customers in Load Profiles 5-8

Micro-generators[61] < 3.68 kW – and household and small business loads[62] - all of which connect at the lowest voltages - comply with technical standards for electrical protection and safety – in particular Engineering Recommendation G83/1-1)[63]. However, some of their physical characteristics (eg protection features, spill etc) are presently not wholly addressed by the distribution engineering recommendations which govern the physical security and reliability of the system. This in turn means that some of the costs associated with their physical location may not yet be *comprehensively* factored into industry approaches to charging[64].

12.6 Low-carbon distributed generation - physical impacts

Distributed generation totals just under 10% of GB installed capacity (~9 GW in 2011), with output somewhat below 10%[65]. There are presently over 2,000 generators < 5 MW (*not including micro-generators)* [66]. DECC estimates that by 2020 there could be ~2.5 million connections of small-scale solar PV [67] with a prospective capacity of~12.5 GW [68].

The key local physical impacts to arise from small low carbon generators – and which require active *local* management by the distribution network in order to defer or avoid additional network management – may be summarised as :

- **Constraint management - thermal, voltage and boundary / bi-directional flow.**

[61] **Small-scale embedded generation (SSEG)** – a source of electrical energy rated up to and including 16 Amps per phase, single or multiple phase, 230/400 Volts AC. **This corresponds to 3.68kW on a single-phase supply and 11.04 kW on a three-phase supply.** Distributed Generation Connection Guide. Electricity Networks Association. November 2011. Version 3.3. p.21. These generators are required to inform the distribution network only ***after installation***.

[62] Load profiles 1-4

[63] eg Engineering Recommendation G 83/1-1 ; Electrical Safety, Quality and Continuity Regulations (ESQCR) 2006 ; IEE Wiring Regulations 17th Edition (BS 7671); Cenelec/BS EN certification for equipment standards).

[64] For customers with demands below 100 kW – so Load Profile 5-8 customers - costs which relate to their capacity (load factor) are to some extent linked to their DUOS charges (next section). For the vast majority of customers in Load Profiles 1-4, no explicitly-related capacity charge (ie no *load-related* charge) is factored into their DUOS charge.

[65] DG generally has lower load factors than large transmission-connected generators

[66] CLNR Commercial Arrangements Study. Element Energy. June 2013. pp.5-6.

[67] Below 30 kWe

[68] CLNR Commercial Arrangements Study. Element Energy. June 2013. P.6

- **Local voltage management**
- **Losses management**

Low-carbon distributed generation – physical impacts

Distributed generation – physical benefits : in general terms, distributed generation can bring the following *physical* benefits :

- **Low-carbon / zero-carbon contribution –** rewarded via the FIT.
- **Reduced electrical losses** : enabling both a system-wide carbon benefit[69] (especially if peak–related) - and also, potentially, deferred network investment at more constrained locations.
- **Off-set / displacement of load - both at the 'national' system level *and* at the local network level** – in *local terms* may enable deferred (or avoided) distribution network investment at a particular location – *especially if that load is offset at peak- periods and the network has a need in that area* (so, a need to reduce thermal constraints, a need for local voltage support).
- **Embedded benefits** – cost-savings that result from the generating plant being connected to the distribution network rather than the transmission network (i.e avoided transmission and balancing costs (so, savings on TNUOS, BSUOS).
- **For CHP plant** : higher efficiencies than producing heat or electricity separately.

Distributed generation - local physical impacts / costs : some of the local physical impacts of distributed generation, including some which arise from their commercial 'must-run' characteristics, include [70] :

- **Change to current flow** – may cause thermal design-ratings of lines to be exceeded (i.e thermal constraints).
- **System voltage rise** - outside statutory and operational limits
- **Voltage imbalance** – affects power quality (especially at particular locations where clusters of PV are connected at single-phase).
- **Increased 'fault-levels'** - above the design-rating of the transformer or network at that location.
- **Reverse power flows** – where equipment not designed to handle bi-directional flows. (Can be redressed by equipment design – eg automatic voltage control systems).
- **Increased harmonics from PV** – gives rise to power impedence.
- **Voltage fluctuation /flicker** – may impact power quality - arises from rapid changes in DG output.

[69] Ofgem note that distribution losses comprise largest component of a distribution network's carbon footprint. Ofgem. 26/13. Strategy decision for the RIIO-ED1 electricity distribution price control. Overview. March 2013. Para 5.25.

See UKPN 2015-23 Business Plan. July 2013. Annex 7. Losses Strategy for a helpful non-technical account about losses and their network impacts (Variable, Fixed etc).

[70] Source : Distributed Generation Connection Guide. Energy Networks Association. A Guide for connecting generation that falls under G59/2 to the Distribution Network. Version 3.3. November 2011. Pp17-18

12.7 New Electrical Loads – physical benefits and impacts

New Electrical Loads – physical impacts

New electrical loads (Heat, EVs) – physical benefits – major new loads from electrification of heat and transport for de-carbonisation goals have yet to make themselves felt, be that on the wider electricity system or at a local level[71]. Assuming that these loads grow as projected and are suitably incentivised or automated, both electric heat and EVs will need to play a significant role in demand-side management both at a system-wide and local level (peak-avoidance, load-building at off-peak times etc).

New electrical loads (Heat, EVs) – physical impacts. Some of the major physical impacts from new loads – both system-wide and local - could include :

- **A significant increase in national electricity demand overall**[72] .
- **Significantly higher evening and morning peaks** – may result in a need for more thermal / fossil generation (higher emissions) ; increased distribution losses (so higher emissions) ; more thermal constraints (so more network investment).
- **Increased harmonics and impact on power quality** - local network re-inforcement.

Presently under the National Terms of Connection smaller loads are not necessarily required to be notified to the distribution networks upon installation [73]. Local physical impacts from

[71] Probably <30,000 heat pumps installed under RHI Premium Payment (RHPP) in the two years from its introduction in July 2011. Probably <10,000 EVs at September 2013.

[72] Potential doubling of electricity demand by 2050 – ref DECC 2050 Scenarios. Ref ?

[73] So, for heat pumps or EV charging points for customers in Load Profiles 1-4.

Non-domestic customers will have a specific connection agreement that specifies the maximum demand permitted (which links to their Load Profile 5-8).

Domestic customers are governed by the National Terms of Connection, which do not specify what is permitted demand. There is no notification process currently for heat pumps and the extent to which a heat pump could be installed consistent with the National Terms of Connection without clearance from the DNO is unclear. The Energy Networks Association is working up a notification process for heat pumps, however, this would be voluntary. A mandatory process might require customers to notify their intention to connect a Heat Pump via their registration for the RHI. The ENA has also come to a view that provided a heat pump complies with the latest EU standards no additional connection charge needs to be made to the customer.

these new loads - *unless managed* - may lead to a need for additional network investment and / or flexible responses *at particular locations where networks are constrained* in the relatively near term.

At a system-wide level, all actors engaged in the electricity market, (DECC, Ofgem, system operator, generators, suppliers, networks) need better data than is available today on likely new load growth, daily customer usage patterns, and load break-down by sector and end-use - nationally, regionally, locally.

Flexibility and load-management at scale will be needed to handle new loads (HPs, EVs). However, should these new loads *not* materialise at scale, then the low voltage networks could be spared the costs of re-inforcing at low voltage for peak-related constraints. With local intermittent generation at scale, but relatively little 'off-setting' flexible new load at low voltage – 'up-stream' network reinforcement at higher distribution voltages *would still be needed*.

12.8 Demand-side actions – local physical impacts

Looking ahead, the distribution networks need a better picture of how both overall and peak demand might grow - and *whereabouts* on their network new peaks may occur so that they can understand where demand-side flexibility may offer a particular value – and signal that to customers and communities who may be able to offer demand-side services *at that location*.

Demand-side actions – local physical impacts

Demand-side actions – overall physical benefits : demand-side actions should offer physical benefits in support of greater economic efficiency and carbon reduction in the electricity system. Just as for distributed generation, these benefits can be system-wide or local - and include the benefits of avoided peak (avoided peak-related investment (peak generation, networks) ; carbon benefit (where fossil plant displaced) ; reduced losses (resulting in both a carbon benefit plus avoided network investment (transmission and distribution)[74]. Electricity demand reduction can also produce savings from avoided investment (generation) and lower carbon emissions (where fossil plant displaced; plus a carbon benefit from reduced losses).

Demand-side actions – *local* physical benefits From the viewpoint of the *distribution networks* flexible demand-side actions could bring the following physical benefits at a *local* level :

- **Peak load shift / permanent reduction** – deferred or avoided investment *at that location* (fault management, constraints) ; reduced losses (variable)[75].
- **General demand reduction** – reduced losses (fixed)[76].
- **The potential for *local* matching of small generation & local demand** (storage, 'buffering' and other balancing) – deferred or avoided investment (releases more network capacity – so may reduce costs associated with new DG connections ; could improve both constraint management and losses. Could improve management of voltage).

Demand-side actions - potential physical impacts : In the long-run, demand-side actions *at scale* could create new physical / cost impacts in the wider electricity system – especially if these actions were either unpredictable in nature - or invisible - to those market actors who needed to be aware (eg system operator or suppliers – for example by creation of *unforeseen* imbalance from demand-side actions and therefore a need for extra balancing actions in the *wider* electricity system[77]). At the *local* level, there do not seem to be obvious adverse physical cost impacts for the distribution networks from demand-side actions.

[74] Ofgem RIIO ED1 Document cites loss reduction as the major contribution to carbon emission reduction by Distribution Networks.

In terms of avoiding new network investment from loss management however, a need for a balanced judgement is likely between (1) increased investment in cable to lower resistance and long-term loss reduction and (2) demand-side response as a means to create greater short-run headroom on losses at particular locations. If DSR enables greater loading on cables (and therefore increases resistance), then losses may also increase as an unintended consequence. In this sense, DSR may create more cable head-room and lowered resistance – and so defer losses – but unless long-term and firm, DSR may be unable to offer equivalence to network investment in terms of guaranteed long-run loss reduction.

[75] See footnote 74 above

[76] See footnote 74 above.

[77] See Sustainability First. GB Electricity Demand Project. Paper 7. Evolution of commercial arrangements for more active customer & consumer involvement in the electricity demand-side (May 2013).

13 Distribution Charges – Treatment of Location

13.1 Introduction

Section 13 looks at how distribution charges treat location. The focus is on customers connected at low voltage (smaller distributed generators, micro-generators and households and smaller business customers).

It looks at :

- How the **locational costs and benefits** - associated with distributed generation and demand - are presently factored into present distribution charging arrangements

– and therefore at

- **How these costs are presently recovered and / or reflected back to the low carbon technologies and / or to the general body of customers**.

Northern Power Grid as a part of the Customer-Led Network Revolution project commissioned Element Energy to produce a helpful paper 'Commercial Arrangements Study' (CLNR website. June 2013) - and on which this section draws[78].

The composition of distribution charges - and how underlying costs are allocated to different components within the charge is complex and not generally visible (e.g for network provision and security, maintenance, operation ; treatment of customer capacity, time-of-use and

[78] Individual distribution networks publish their charging principles and methodology - and their annual list of charges - on the commercial sections of their websites. Ofgem and the Energy Networks Association publish industry-focused materials about the detailed approaches to distribution charges – including on the Common Connection Methodology (CCM) and the Common Distribution Charging Methodology (CDCM) arrangements. Terminology is technical / historic. The cost-allocations which relate to location – including the split *between* connection charges and distribution use of system charges – and also *within* the connection and use of system charges - are complex and not necessarily clear. Cost-allocations *within* DUOS for different voltages, between different customer groups (eg half-hourly and non-half hourly metered) are also complex.
See also Northern Power Grid slides (November 2009) for a somewhat historic but relatively user-friendly description of the structure of DUOS charges.
http://www.northernpowergrid.com/som_download.cfm?t=media:documentmedia&i=500&p=file

customer location). Small generators, local groups and others with an interest in the local electricity demand-side may struggle to understand the underpinnings of distribution charges – *including how the location at which customers are physically connected to the network impact distribution charges*. A simple guide on distribution charges and how networks recover their costs would help.

Distribution charges take account of location in two ways : in part via a Connection Charge (where applicable) and in part through DUOS (Distribution Use of System charges).

13.2 Connection Charges – treatment of location

Connection charges are intended to convey a signal to customers, from a network perspective, as to where it is cost-efficient to locate. Larger customers of the distribution networks pay a connection charge direct to the distribution networks. This charge recognises the costs of providing physical assets – either to connect that generator's declared capacity and / or that customer's maximum load *at that particular location* on that distribution network, as follows :

- **Generators over 3.68 kW[79] .**
- **I&C customers with a load over 100 kW who are half-hourly metered**.
- **Non-domestic customers (Load Profiles 5-8)** - have a specific connection agreement which specifies the maximum demand permitted.

These customer groups can be required to pay a connection charge to the distribution network if their connection will cause the need for reinforcement or upgrading or other work. Typically, this includes the direct costs of connection and 'shallowish' charges of *local* re-inforcement (i.e. not extending far up the network). The principle is that of the 'last straw' – i.e. provided a connection can be made within the capacity of the local substation, no connection charge is required, but if re-inforcement is necessary at the transformer or to the network, then there will be a charge for a proportion of the additional cost.[80]

[79] 11.04 kW if three-phase

[80] If also needed, the network then picks up re-inforcement costs at the next level of voltage.

Sustainability First. GB Electricity Demand project. Paper 5. 'The electricity demand-side and wider energy policy developments. November 2012. Pp 61-2.

Micro-generators below 3.68 kW - and smaller household / small business customers[81] who may connect a heat pump or an EV charger - are not at present required to pay a connection charge. As such, the costs of assets associated with connecting micro-generation (or a heat pump or EV charger) *at a particular location* are not at present *explicitly* recognised in a separate connection charge payable to the distribution network. Instead, connection – related costs for these customers are recovered via DUOS charges – in effect from *all customers*. Domestic customers are governed by the National Terms of Connection, which do not seem to specify what is 'permitted' demand.

13.3 **Distribution Use of System Charges (**DUOS) **– treatment of location**

DUOS charges recover the costs allowed by the regulator for installing, maintaining, operating and developing a secure, safe and reliable distribution network – and amount to ~16% of a customer's end-bill.

All DUOS network charges are payable *by suppliers* to the distribution networks.

DUOS charges are *not* designed to offer a direct signal to suppliers - or to network customers (distributed generators, end-customers) - about the costs of where they physically locate on the lower voltage distribution networks[82]. This *contrasts with* Transmission charges which, as noted, incorporate a direct zonal signal to transmission connected generators, electricity suppliers and large half-hourly metered customers.

The industry-wide common distribution charging methodology calculation for DUOS, models the costs associated with – and the charges to be allocated to - each network voltage. **Location is therefore broadly factored into the p/kWh unit charge for load - and for generator credits – *for each distribution network voltage,* but is not an explicit or visible locational signal.** Distribution charges also vary *between* the distribution networks, shaped by the costs associated with the characteristics of that network (e.g. asset age, rural, suburban, urban etc).

DUOS charges[83] are therefore not designed or intended as a vehicle for conveying a *locational signal* to suppliers (or to their customers) in terms of the value which demand-side actions *at a particular place* might represent to a DNO.

[81] Load Profiles 1-4

[82] But EHV DUOS now includes a locational (site specific) charge.

[83] At HV and LV

13.4 DUOS charge elements – & location

For both distributed generators and for demand customers, suppliers' DUOS charges are determined by a 'pick-and-mix' of charge elements comprising : a unit rate (p/kWh) dependent upon the level of voltage of connection plus the particular user-group or customer profile (generator / individual customer) ; and for larger generators or customers the export capacity of the generator or the import capacity of the load connected ; the load-factor of the generator or the load.

All of this adds up to a fairly complex combination – as noted, levied as a 'back-office' charge by the distribution networks ***from suppliers***. From a supplier perspective, their DUOS charge liability is shaped by the make-up of the generation - or the load - of their total customer base - and over which they have little control or influence. In sum, location in DUOS charge components is reflected as follows :

- DUOS Charges at EHV give a direct signal regarding the costs and benefits of location for large generators and the very largest I&C customers.

- For some larger HV-connected generators with half-hourly metering - and large I&C end-customers with a load over 100 kW and who are half-hourly metered and settled - distribution network charges are simply passed through to them by suppliers and so visible – but anyway incorporate only a very indirect 'locational' signal - via the ToU band and / or via the capacity element of the DUOS charge.

- For non-half hourly metered generators, for all micro-generators and virtually all end-customers - DUOS charges factor location into the calculation of the voltage-level p/kWh charge – but do not incorporate an identifiable locational signal for suppliers (nor for their end-customers).

The boxes below show how DUOS charges reflect location at different voltages. Annex 1 includes a more detailed description of DUOS charges.

EHV DUOS Charges – take express account of location of customers connected at Extra High Voltage. This is intended as a signal to help defer / avoid network investment and / or to release network head-room.

EHV charges *are visible to these largest network customers* because suppliers generally pass the DUOS charges directly through to large customers and generators directly.

- **Demand > 100kW** – a locational demand / capacity charge which varies by individual customer. Also, a unit-rate which is banded by ToU ; Fixed Charge (p/meter/day) ; Capacity Charge (maximum import capacity) – and *exceeded* capacity (p/kVa/day).

- **Large Generator** – takes account of location via higher *generator credits* in areas where there is little spare network capacity (p/kWh). Also, *for non-intermittent generators*, a ToU banded 'super-red' unit credit *at peak* (i.e. an even *lower* p/kWh charge at peak). Fixed charge (p/day) ; Export capacity charge (p/kVa/day) – *plus* an exceeded capacity charge.

High Voltage (HV) and Low Voltage (LV) DUOS Charges – do not take *explicit* account of location (unlike EHV DUOS charges) – **but for half-hourly metered customers - and for larger generators – components of the DUOS charge are arguably a proxy for location (i.e. the ToU element ; the Capacity Charge (and the excess capacity charge).**

- **Demand –** p/kWh unit rate – varies by network voltage and ToU banded for half-hourly customers ; Fixed charge (p/meter/day) which *for non-half hourly customers* includes a capacity factor ; Maximum Import Capacity charge for half-hourly customers ; Reactive charge for half-hourly customers.

- **Distributed Generators** – half-hourly metered generators at HV receive *credits / payments* for their exports in the DUOS unit-rate (p/kWh). They also pay an export capacity charge and a fixed charge (p/meter/day) – this varies significantly across distribution networks (eg 6-230 pence per meter per day)[84] ; Half-hourly metered generators pay a reactive power charge.

[84] Element Energy. Customer-Led Network Revolution Commercial Arrangements Study. CLNR-LO32. June 2013.

13.5 Conclusion - how 'local' is treated in distribution charges

Therefore, at a high level, distribution charges (Connection and DUOS) can be said to treat 'local' in the following way :

Locational *costs* are generally factored into distribution charging frameworks for :

- Larger distributed generation
- Larger Loads (Half-hourly & Load Profiles 5-8)
- *Existing* household loads and small businesses (Load Profiles 1-4)

But, locational costs are not comprehensively factored into distribution charging frameworks with regard to :

- Smaller generators <3.68 kW
- Additional or new loads installed by households and small business customers (Load Profiles 1-4). (e.g. power showers, storage heaters, heat pumps, EV chargers).

Locational *benefits* are generally factored into distribution charging frameworks for :

- Distributed generation – for larger DG via lower connection charges or via the 'embedded benefits' of avoided TNUOS & BSUOS charges which they can negotiate / receive from a supplier via a power purchase agreement ; (and, arguably, from the smaller DG point-of-view, including micro-generators, some non-locational benefit acknowledged via the FIT deemed export tariff (both for metered and for unmetered spill)).

But, the benefits which may attach to demand-side activity at particular locations are presently not *systematically* acknowledged in present network charging frameworks (be that for DSR, demand reduction or for storage). In effect, within the DCUSA[85] there is presently no demand-side equivalent to 'embedded benefits' : so, no formal acknowledgement or 'discount' in the industry network charging arrangements if the demand-side helps to avoid some elements of TNUOS, BSUOS and, potentially, EV DUOS charges. Recognition in DCUSA of *local* demand-side benefits would almost certainly require some kind of subsequent verification of demand-side delivery at the customer- or community-level - and this would add complexity.

Nonetheless, it is important to note that benefits *are* presently available to those providing demand-side actions and services to the networks *via 'ad hoc' bilateral agreements*. As these

[85] DCUSA – Distribution Connection and Use of System Agreement.

demand-side benefits are most likely to be delivered only at very constrained locations on the networks, such ad hoc approaches to recognising the financial benefits may well be appropriate for now, at least to the end of ED1 in 2023.

13.6 **Conclusion - on visibility of distribution charges to the end-customer**

The following distribution charges convey some kind of *visible* signal about location to the end-customer :

- Connection charges – (may apply to distributed generators >3.68 kW and I&C loads down to Load Profiles 5-8)

- The separate capacity and ToU elements *within* DUOS charges (apply to half-hourly metered generators and customers).

For all other network end-customers – locational signals are not visible to them because these charges are paid by suppliers via the settlement system. Even where locational signals do exist in practice (i..e within distribution charges to suppliers), any signal is at best weak. So, for :

- **350,000+ plus small micro-generators below 3.68 kW and**
- **29 million end-customers[86]**
- **Community or local groups wishing to take group or collective action.**

The Table overleaf, adapted from the CLNR Commercial Arrangements Study by Element Energy[87] gives a high level overview of the strength of the incentives currently available to the distribution networks in encouraging where distributed generators site / locate.

[86] Ie Chiefly load profiles 1-4 – (but also 5-8 to some extent).

[87] Element Energy. Customer-Led Network Revolution Commercial Arrangements Study. CLNR-LO32. June 2013.

Overview of incentives available to distribution networks to influence where distributed generators choose to site on their networks.		
Distribution Network Voltage	**Incentives available to distribution network to influence generator location**	**Comments – size of market**
EHV	**Strong** – **EHV connection and capacity charges are high**: they incentivise efficient siting and design with respect to network reinforcement. DNOs can contract with EHV generators for generation-side management	~60% of on-shore wind turbines are EHV connected (this ratio likely to stay the same to 2020).
HV and LV (generators *over* 3.68 kW single-phase / 11.2 kW three phase)	**Medium** – Distributed generators receive either the RO or FIT. This is *independent* of location on the network. But, these generators pay connection charges and capacity payments – which help to encourage efficient siting.	HV-connected. ~1,200 generators with an output of ~7,300 GWh.
LV – Small-Scale Embedded Generators - *below* 3.68 kW single-phase / 11.2 kW three phase	**Weak –** Small Scale Embedded Generators do not pay connection charges. They receive a strong 'must-run' incentive via the FIT. **There is no incentive for these generators to locate at those places / locations where networks where they are best able to handle the physical impacts.**	Sept 2012 - ~330,000 installations. Predicted to rise to ~2.6m by 2020
Source : Adapted from : Element Energy. Customer-Led Network Revolution Commercial Arrangements Study. CLNR-LO32. June 2013. Table 4.3. P.42 'DNO Scope of Impact on DG Installation'		

Table 2 below, adapted from the CLNR Commercial Arrangements Study by Element Energy[88] gives a high level overview of how network location is currently reflected to different customers groups in network charges.

How network location is presently reflected in network charges to different customer groups.			
Type of Customer	**Total customers (by meter point[89]).**	**Proportion of annual load**	**Locational signal incorporated into separate Connection and / or DUOS charges ?**
EHV connected – half-hourly metered and settled.	~10,000 total	~ 100 TWh pa (so, ~27% of all annual load).	**Locational signal via** Connection charge. Plus : Seasonal super-red tariffs (time-related) & capacity charge. Also, distribution networks can contract directly with large EHV-connected customers for demand-side management.
HV or LV connected – Half-hourly metered and settled	~100,000 total	56 % (includes the EHV load above)	**Strong incentive via:** Connection charge Plus time-related charges (three unit rates as defined by DN) ; separate capacity charge.
LV connected – Non Half-Hourly metered / settled.	29 million customers (99.5 % of all customers) (44% of all load) – of whom : 82% of all customers (28% of load) are on a single unit charge 'unrestricted' tariff 17.5% of all customers (16% of all load) – who are on 2 unit rates (i.e. off-peak).		Within the DUOS charges for non half-hourly customers there is not a separately identifiable / or visible charge which relates to *customer location*. This is because within their 'bundled' network charges these customers do ***not*** pay : a connection charge a separately identifiable element which relates to capacity (although Load Profile 5-8 DUOS charges relate to an assumed load-factor). a time differentiated charge (unless Economy 7 – Load Profiles 2 & 4).
Source : Adapted from : Element Energy. Customer-Led Network Revolution Commercial Arrangements Study. CLNR-LO32. June 2013. Table 4.4. P.47 'DNO Scope of Impact on DG Installation'			

[88] Element Energy. Customer-Led Network Revolution Commercial Arrangements Study. CLNR-LO32. June 2013.

[89] By MPAN – meter point administration number.

14 Distribution Charges – How might these become more supportive of the local demand-side?

Section 14 discusses whether distribution charges might in time evolve to incorporate greater cost-reflection to reflect the potential value (costs and benefits) of demand-side activity at a particular location. Greater cost-reflection could in principle entail signals which are explicitly locational – but in practice might not.

Initially, any such signals could, as now, simply be faced by suppliers.

Or, in the longer-term, stronger local demand-side signals could be communicated directly by the networks to end-customers and / or to communities connected to the low voltage networks.

Potential consumer issues in moving to more under-lying cost reflection in distribution charges is discussed at a high-level in section 15.

14.1 Certain actions on the customer demand-side create new costs at particular places on the distribution networks – but these costs are presently recovered on a socialised basis from *all* distribution customers via DUOS charges.

As noted, connection charges are not payable by micro-generators <3.68 kW – or by household and small business customers who connect some new loads [90] . Instead, any new costs for the networks created by the activity of these customers are recovered from *all* distribution customers on a socialised basis via DUOS.

Micro-generators and customers with flexible load are key groups - who at scale may in time become significant local demand-side players – but presently receive no signal or message via distribution charges (either connection or DUOS) about the costs (technical inefficiencies) or the benefits (technical efficiencies) of the impact of their activity in terms of where they are located on the network.

Ofgem's ED1 document notes that network reinforcement costs relating to connection of micro-generators, HP and EV charge-point customers - will continue to be socialised across *all customers* via DUOS charges until 2023 (ie end of ED1)[91]. This acknowledges that these

[90] i.e. Customers in Load Profiles 1-4.

[91] Ofgem's initial aim would be to give a stronger signal to smaller customers of the *costs* which they may create on the low voltage networks (micro-generators; new loads such as HPs, EV chargers) and which are presently borne (arguably somewhat unfairly) by *all* customers. Ofgem has indicated that this will *not* be

customers are actively helping to deliver policy goals on low carbon ; and, also have little flexibility on *whereabouts* they connect.

However, without some kind of eventual signal or message to customers about their operational efficiency i.e. time- or price-related efficiency - at the local network level – (and / or their *locational* efficiency)**,** it is hard **to inform them - or to give them knowledge or insight - into *either* the *cost* or the *benefit of connecting their low-carbon technology – or load - at a particular place on the network.*** A small customer's decision to install micro-generation - or a new large electrical load - remains poorly informed about the *locational* costs and benefits they bring, be that at their home or their business.

Importantly, if in the long-run, costs of micro-generation and new load such as electric heat and EVs are not somehow passed back to those customers which 'create' them, an affordability / fairness question arises for all other customers[92].

14.2 Tools presently open to the distribution networks to send stronger signals about customer demand-side actions

Distribution networks are incentivised to cost-efficiently manage any network disturbance or constraints which their customers - distributed generators, micro-generators or new loads - create on their networks – (LCNF, DPC5 TOTEX, ED1) – and recover the costs via DUOS.

Some of the tools presently available to the networks to send locational demand-side signals are :

- Connection charges – but, as noted smaller customers and micro-generators <3.68 kW do not pay connection charges.

- Non-firm connection agreements – trials of non-firm connection agreements are beginning to 'reward' both larger generators and customers for flexibility in their output / consumption patterns.

- Bi-lateral load-management agreements with large I&C customers connected at EHV or HV.

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addressed before the end of the ED1 Smart Grid period, but Smart Grid Forum Work Stream 6 is starting to consider.

[92] Discussed in Sustainability First GB Electricity Demand project. Paper 5. 'The electricity demand-side and wider policy developments' November 2012. Pp 61-63.

- Signals conveyed *to suppliers* in DUOS – which, as noted, are weak with respect to *locational* impact (and anyway not visible to most end-customers).

14.3 Possible steps to create clearer messages *to suppliers* regarding the local demand-side actions of their customers ?

Distribution charges for distributed generators and customers are payable *by suppliers* to the networks. There are a number of proposals presently being discussed by industry working groups for 'initial' reform to the distribution charging methodology, so that *suppliers* would face stronger incentives than now – which in turn might be expected to motivate suppliers to offer new retail tariffs to their end-customers to encourage customer demand-side actions[93]. These include :

- Aggregated ToU Distribution Charges at Low Voltage – introduction of a *universal* time-of-use component to DUOS charges *at low voltage* [94].

- Capacity charges for all customers (see 14.4 below).

A number of issues arise :

- Time of use element in low voltage DUOS charges to suppliers : to charge suppliers on a time-of-use basis for *every* low-voltage customer – even where a network may not be constrained - is arguably a blunt instrument if the main object is to address *specific* network constraints at *specific* locations ; supplier interest in alignment with static ToU network charges may diminish with increasingly wind-driven wholesale prices in the future ; incentivising suppliers to shift large numbers of end-customers onto static ToU

[93] Common Distribution Charging Methodology group. There are current discussions on DCUSA change proposals – aiming to introduce possible *interim* changes to non-half hourly DUOS charges *for suppliers*, (pending availability of half-hourly data from smart meters). These include consideration of (1) a notional capacity element for non-half hourly metered customers and (2) the introduction of *aggregated* ToU DUOS charging profiles at low voltage levels (HV & LV).(Depending on how this latter in the end is done for settlement purposes, it may or may not facilitate more 'local' approaches to DUOS charging – unless, as smart meters roll-out, DNOs opt to receive selected geographic half-hourly data from the DCC, which could be expensive).

[94] Larger generators and customers connected at EHV (and some half-hourly load at HV) already have a ToU element in their DUOS charges – to reflect the broad benefit or cost to the network of either generating or consuming at peak. However, this ToU charge *is not location specific – but is universal* depending on network voltage. While this may help to improve efficiency by more closely aligning large customer network charges with wholesale energy prices, it may in practice deliver a somewhat limited benefit in terms of alleviating *location-specific* constraints.

tariffs may have unforeseen cost and distributional impacts for customers if they are unable to shift their load at peak.

- These proposed new charges (ToU, capacity) would still be invisible to end-customers – unless suppliers made them visible in bills (which would have a cost).

14.4 Possible steps to create clearer messages to *end-customers* about the potential value (or costs) of their demand-side activity ?

Most customers and small generators[95] are wholly unaware of the distribution charges which suppliers pay on their behalf.

Even if they were aware, the detailed elements of how network charges are constructed, the under-pinning assumptions on customer off-take or power-injection – particularly in relation to their network location – and the relationship to the *actual* consumption of individual customers - or groups - *at a particular network location* is neither direct nor visible to the vast majority of customers and small generators.

A number of questions therefore start to arise both for Ofgem and for the distribution networks, about present treatment of *local* costs and benefits in distribution charges, **including whether in practice stronger, more cost-reflective signals directed at smaller network customers -** could be *beneficial* in practice in encouraging more targeted local demand-side activity as a tool to help manage constraints and to reduce losses.

If there was a wish to start to provide sharper signals at low voltage in distribution charges, to encourage more demand-side activity and more local-level balancing – some options for initial consideration and further discussion might be :

- **Explicit separation of network charges by suppliers in consumers' end-bills** - to drive greater visibility / transparency.

- **Introduction of connection charges for micro-generators** - and potentially perhaps for new loads such as HPs, EV chargers (but see next para on capacity charges).

- **A possible new and explicit capacity charge in DUOS for all demand customers at low voltage** (based on annual maximum import capacity) – including an 'excess' capacity

[95] Smaller customers here are : 29 million load profile 1-8 customers. Small micro-generators with a single phase connection below 3.68 kW

charge[96]. Such a charge would seem supportive of local demand-side activity, local-balancing, matching and local storage. A capacity charge also seems a relatively well-targeted and effective *locational* incentive – including for new load such as heat pumps and EV chargers – because it internalises the costs to the customer who adds new demand, and potentially how they use it (e.g. a capacity charge could be avoided by shifting load away from peak times). A capacity charge would recognise location, in the sense that clusters of new load (so, HPs & EVs) would *each* pay a higher capacity charge at that location unless they engaged in demand-side management. It could either be a direct kW charge – or some kind of 'subscription' to a level of off-take eg 5kW, 10 kW [97]. A capacity charge may arguably be 'fairer' than an *explicit* locational / post-code charge (see 14.5 below).

- **ToU Distribution Charges at Low Voltage** – see 14.3 above [98].

Any of the changes outlined above would need careful consideration with regard to the likely pros and cons. Introduction of a connection charge and / or a capacity charge for smaller customers could be controversial - especially if in some way either retrospective - or targeted at particular equipment.

If such changes were to be introduced simply into DUOS charges for *suppliers*, some of the changes (but not all) may require smart meters plus half-hourly data.

If these changes were to be introduced as *separate network charges billed direct to individual end-customers*, it is likely that both smart meters and half-hourly settlement would in the end be needed. This would offer the capability to more readily *reward individual-level actions* which supported greater network efficiency.

As Ofgem has noted, timing on such decisions may work well with the end of the ED1 period in 2023[99].

[96] Just as for all I&C half-hourly customers now. The DECC / Ofgem Smart Grid Forum Work Stream 6 is currently considering the potential impacts of a variety of such options, including a potential two-rate capacity charge. The Common Methodology Charging Group is also considering a DCUSA proposal for a possible capacity element for non half-hourly DUOS (chargeable to suppliers).

[97] As in France, Italy.

[98] Larger generators and customers connected at EHV (and some half-hourly load at HV) already have a ToU element in their DUOS charges – to reflect the broad cost to the network of either generating or consuming at peak. However, this ToU charge *is not location specific – but is universal* depending on network voltage. While this may help to improve efficiency or resolve *location-specific* constraints – it is arguably perhaps a rather 'blunt' instrument. See Annex 1 for discussion of possible pros & cons of TOU DUOS charges at low voltage.

14.5 More explicit locational approaches to network charging ?

The options for distribution charges noted in 14.3 and 14.4 above would, in principle, be somewhat more cost-reflective and so bring more demand-side cost-efficiency. They could apply equally and consistently across customer groups – and should offer some locational benefit. However, none of the options discussed above are *explicitly locational.*

Going a further step, it would be feasible (in principle at least) *to differentiate network charges and network billing at different locations* – from street level upwards. Such *locational cost-reflection* in distribution charges – potential 'post-code' approaches to network charging – are arguably more controversial [100] .

The potential pitfalls of any ill-considered move towards 'post-code' charging approaches were raised with us in discussion.

For example, early insight from one LCNF household trial had indicated very variable consumption at different network locations - seemingly relating to different customer demographics at different places. One early lesson was that high customer usage at peak (or at other times) did not necessarily map neatly with network locations which were particularly constrained and so most in need of re-inforcement. Conversely, some customers at constrained parts of the network were perhaps among demographic groups judged less able to be flexible at peak (and / or who might be more disadvantaged).

These early insights would seem to suggest that *explicitly* locational or 'post-code' charging approaches to DUOS may have some basic drawbacks. They may run the risk of being poorly targeted and have potential distributional or other unintended impacts - without any guarantee that they could deliver a significant gain from a demand-side perspective.

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[99] In reality, progress in developing consistent and systematic ways to better signal locational costs and benefits will be long-term. Small generators will need export metering capable of recording half-hourly data (export meters not presently required for small DG <30kWe) ; customers will need half-hourly metering – and probably half hourly settlement too – in order for costs and *benefits* to be accurately fed back to the customers who originate them. So, on timing, improving locational signals in distribution charges *after ED1* (2023) is probably about right.

[100] In principle at least, explicit locational charging may be relatively straightforward to deliver. Suppliers can already identify customers at a local level – via either their billing system or the meter registration system. Equally, distribution networks can also identify customers at a local level (but in practice have no present need to do so). In the future, with access to customer half-hourly smart meter data, suppliers will also be able to aggregate 'local' half-hourly data into 'local' profiles. (Email exchange with Elexon. November 2013).

Further, the benefits of moving away from the present approach of socialising cost-recovery of DUOS charges across an entire DNO area (i.e. differentiating only by voltage) were also queried.

From a consumer, supplier, and distribution network perspective the benefit of any move to a potentially more explicit 'local' or geographic approach to cost-recovery of distribution charges were felt to be open to question. For all of these reasons, explicitly sharper locational signals in distribution charges would need very careful consideration.

Instead, it was felt that distribution networks might be more likely to wish to extend some of the bi-lateral approaches they are already developing with I&C customers[101] to other smaller customers at network locations which are constrained.

Having far better information on the whereabouts in their networks of clusters of PV, heat-pumps and EV chargers, would help distribution networks target particular localities for any such bi-lateral arrangements.

14.6 How to reward local or community groups who wish to take collective demand-side actions ?

The present structure of distribution charges seems generally to overlook the possibility and / or prospective benefits of *collective, group or community* demand-side actions at particular locations.

For customers, both a connection charge and distribution charges are determined at their individual meter point. This means that for a local group or for a local community with a defined geographic base, however small or large, their distribution charges are calculated in terms of their individual meter points.

A group of individuals *who wished to act collectively - as a local demand-side group* – would continue to have their network costs met individually - via their separate suppliers – and without any visibility to the individuals – nor, importantly, at the group-level.

It is also not clear how giving stronger locational signals *to individual customers* could help to realise the *collective locational benefits* of demand-side action at group or community level (e.g. balancing at a community level). Two possible ways for distribution networks to recognise community level benefits might be:

[101] See Section 13

- Separate bi-lateral *community-level* agreements with distribution networks for demand-side services, albeit this raises issues about how a community might enter into such an arrangement (perhaps via a local authority, supplier, aggregator or other third party ?).

- A DUOS rebate (from suppliers) for *communities* who provide firm demand-side benefits to the network at a particular location / substation *which is constrained* [102]. Any such rebate might be akin to the 'embedded benefit' treatment of distributed generators in their power purchase agreement with suppliers. So, insofar as the demand-side service provided avoids TNUOS, BSUOS, and, possibly, EHV DUOS, some form of recognition for this. Some kind of metered validation / proof would almost certainly be needed to demonstrate delivery, so that suppliers (and the market generally) could be satisfied that any rebate of load-related network charges was justified.

Even with potential acknowledgement in distribution charges for local community demand-side contributions, other considerations are likely to come into play for the networks:

- It is uncertain how far local matching / balancing of supply and demand may **be incentivised - unless the 'reward' which the network could share with the group or community was fairly significant.**

- Possible issues may arise for the DNOs, given their 'non-discrimination' duties, in terms of developing closer bi-lateral relationships with some customer groups and not others ; and, in similar vein, DNO even-handedness in approaches to developing relationships with third-party providers : local authorities, social landlords etc.

For the future, even where demand-side actions *could* secure benefits / efficiencies at constrained network locations, it is uncertain how the distribution networks might set about publicising and sharing any reward / benefit with those demand-side actors on a *systematic and transparent basis – including with communities.* For example, reform of the DCUSA may be needed to enable the equivalent of 'embedded benefits' or discounted DUOS for demand-side services at constrained locations on the network.

For the time-being, any such benefit-share for demand-side services seems more likely to be offered to customers on a more ad hoc and bi-lateral basis - by those networks who have particular problems at very constrained network locations.

[102] Element Energy (page 60) suggest that the Distribution Connection and Use of System Agreement (DCUSA) would need amendment before the CDCM could adopt regionally different approaches to the structure of DUOS charges.

14.7 How best to flag-up the most constrained places on the LV networks for demand-side actions ?

It is presently hard to understand *in a systematic way* what financial or commercial value local matching can bring – be that from the viewpoint of a household, local neighbourhood or a wider community level – or indeed for a network at a particular local feeder, substation or grid supply point.

There is presently no *formalised* process by which a distribution network can acknowledge - via either connection or distribution charges - that certain individuals, local groups or communities – either because of *where they live or where they work* – could potentially *help* a network avoid network reinforcement costs through 'firm' demand-side activity (be that DSR, demand-reduction, storage, local generation)[103].

Similarly, customers who are open to – or interested in – offering electricity demand-side services, presently *have no ready way of knowing whether their demand-side activity (including micro-generation) could bring any value to their local network (or indeed create a cost).*

Some notion of what 'value' / reward may be available for their demand-side services seems important.

Distribution networks may therefore wish to consider **(1) how best to flag where the most constrained places on the LV networks are in terms of potential demand-side actions and benefits** and **(2) how to introduce some visibility / transparency on the potential demand-side savings available to share at different network locations with would-be local demand-side providers.**

Also, simply to note : exploring ways to communicate greater visibility and transparency on network locational costs – does not in itself imply a more radical jump to locational, 'post-code' or explicit locational network pricing (see 14.5).

Distribution networks may wish to consider how best to communicate in systematic ways the most constrained places on their networks which could stand to benefit from local demand-side actions. The 'heat-maps' being developed for distributed generation may be a good start-point.

[103] This might be by helping to alleviate a network constraint ; by helping to offset losses (and therefore carbon) ; and / or to offset the impacts of local generation.

15 Consumer issues : cost-reflection and local supply

This paper touches only briefly on some of the potential customer and consumer issues which arise with respect to development of a more local demand-side. We will return in Paper 12 to the topic of what greater cost-reflection, both in retail energy tariffs and in network charges could mean for end-consumers [104].

15.1 Wider consumer issues : cost reflection in network charges

Future evolution of distribution charges is an important consumer issue. Any move towards greater cost-reflection in network charges – designed to develop stronger and more cost-efficient *local* demand-side signals[105] – may also have the potential for adverse customer impacts - especially if these were to be *directly payable by end-customers*.

In particular, and as noted, network pricing signals which may be *explicitly locational* may be controversial – for example, in regions, areas or places where individual customers, groups of customers, or particular communities may be *unable* to respond with flexible demand-side actions. A network may be constrained for historic reasons - or because of new distributed generation or new load connecting leading to insufficient spare network capacity. Given that moving elsewhere is not a serious option, possible impacts on different groups of end-customers which could result from reflecting sharper locational signals in network charges to end-customers – and in particular any potential distributional impacts – will be an important consideration of any evolution of network charges in future.

From a customer viewpoint, some possible issues to consider in terms of any move to greater cost-reflection in network charges *direct to end customers* include :

- Connection and / or capacity charges : retrospective introduction of such charges (eg for PV, electric heat or EVs) may seem 'unfair'.
- Explicitly *locational* network charges : may not necessarily produce a good locational 'match' between constrained parts of the network and customers who are in practice able to respond with flexible demand-side actions (and could well penalise customers at constrained locations who are *unable* to be flexible)[106].
- Possible distributional impacts : of any move to more 'extreme' locational - or even 'post-code' - low-voltage network charges.

[104] In Paper 8, we looked in detail at household consumer issues likely to arise from development of the electricity demand-side, including consumer issues relating to development of smarter retail markets beyond the relative short-term of the Retail Market Review. Ofgem has just published a consultation on Consumer Empowerment and Protection in smarter markets (16 December 2013).
[105] Discussed in section 14
[106] See 14.5 above

15.2 Wider consumer issues : customer and consumer considerations in seeking a better 'match' between local energy and local demand

In drafting this paper, a number of wider considerations were raised with us regarding some high-level issues for consumers which would require further consideration in seeking to develop a better 'match' between local energy and local demand :

- One significant consideration for both suppliers and for the networks is the extent to which reliance on the local demand-side may increase commercial risk and reliability risk – both for local customers and for the networks. Reliance on local customers may increase the risk of non-delivery for the networks – especially if the dependence was on households[107]. Local network re-inforcement may well be seen as a less risky commercial proposition for assured delivery of resilient networks - both from a network perspective and in the end for customers in general [108].

- Distributional impacts *at a regional level* could result if customers become increasingly reliant on *local* energy supplies : for example if *local* demand had strong 'peak' characteristics – but local generation was largely intermittent – then consumers might well be better served by their supplier making wholesale energy purchases in a nationally interconnected and traded electricity system.

- From a non-discrimination stance, interaction between DNOs and some groups of consumers - rather than others – may need further consideration. Similarly, interaction with third-party providers, including local authorities, social landlords etc.

- Customers not able (for whatever reason) to actively participate in *local* energy markets, may over time be faced with paying for a higher proportion of the overall fixed costs of the electricity system. In the long-run, success at scale in local matching of supply and demand could potentially leave a diminishing customer base from which to recover the continuing fixed costs of providing the transmission networks and the higher voltage distribution networks and national-level balancing[109].

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[107] The planned revision to the Engineering Regulations (p/26) will update guidance on how far it may be wise to depend on customer flexibility / customer interruption for future network design and resilience.

[108] For example, where a bi-lateral DSR arrangement ends, and network re-inforcement is then required, customers in general would still end up paying via DUOS charges

[109] Also raised by TSB KTN paper on Community Energy Supplies.

- There is likely to be a need for suppliers to *demonstrate* / *validate* the match of local demand with local supply, to justify any possible discount or rebate on network charges which may be available to them (or their 'local' customers) for their demand-side contribution. Otherwise, without validation that supply is locally consumed, other suppliers (or other customer groups) may face higher fixed network and balancing costs than warranted (for transmission, distribution and for national-level system balancing). For a successful local demand-side, validation of *local* supply may therefore be needed *in addition to* half-hourly export metering and settlement.

- The reward for savings achieved from local demand-side efficiency between the network and the customer (or their supplier) will need to be transparent and clear to all parties. Under the price control efficiency incentive, the networks are strongly incentivised, by being able to retain up to 70% of any savings within a price control period. This suggests that the basis on which any demand-side savings would be rewarded and shared between the network, suppliers and their customers or community groups, would need to be both fair and clear.

- Low-cost forms of storage could deliver a cost-efficient 'buffer' between local supply and local demand – whether this 'buffering capability' be at the level of an individual household - or at the level of a distribution network. In section 12 on incentives, we note a 'gap' in present demand-side incentives in terms of support for modest thermal storage solutions (e.g. adaptation / re-wire of hot water cylinders, new-style storage heaters[110]) and in Paper 11 we will return to the question of how far options for household-level thermal storage are presently somewhat overlooked as a low-cost storage solution capable of being delivered at scale. Significant break-throughs in storage technology and cost (battery or thermal), able to 'match' local PV or wind output with local customer demand, have the potential to revolutionise approaches to local energy supply and the development of local energy markets. A comprehensive paper by PWR Consultants explores the role of network-attached storage and some of the technical, market and regulatory barriers to consider, in development of Local Energy Markets in GB [111].

'The Role of Community Energy Systems in the UK Resilient Energy Supply'. A Study by the Smart Energy Special Interest Group (SE SIG) for the Information & Communications Technology Knowledge Transfer Group of the Technology Strategy Board. April 2013.

Also, SE SIG Community Energy Systems Foresighting Project. Final Report. July 2012.

[110] Water cylinders offer a good year-round match for PV and wind. Storage heaters have a poor match in absorbing excess power in the summer months.

[111] LEMMA Work Package 3 for TSB. 30 December 2012. Mike Parr. PWR consultants. www.pwr.co.uk

Part III - Ofgem and the Distribution Networks – what they are doing to improve 'local match' between local supply and local demand.

In their RIIO ED1 Strategy Decision Document[112], Ofgem says :

> 'Smart grids technology and associated contractual arrangements with customers and generators may offer DNOs a more cost effective way of resolving constraints on the network than investing in more assets. They may also provide the DNOs with more flexibility, especially where they are unsure of longer-term demand….The LCN Fund is funding trials to assess the potential operation and benefits of smart technologies (including storage) and DSR, among other things'.

Ofgem and the DNOs, market actors, and others such as DECC, TSB and the Research Councils, are now actively supporting many local demand-side trials - including exploring how 'firm' load-shifting and demand reduction might work in practice as an 'off-setting' alternative to network investment – as well as initiatives on storage. LCNF projects which explore 'local-balancing' of supply and demand will be helpful - not just from a technical and engineering stance – but also in terms of getting to grips with the administrative, regulatory and commercial challenges in making 'local-matching' of supply and demand a replicable reality.

Some current initiatives by Ofgem and the distribution networks which may serve to support a better 'local match' between supply and demand are noted below.

16 Ofgem – initiatives to improve 'local match'

16.1 Ofgem - Generation-related initiatives to improve local match

- **Non-firm connection arrangements** - encouraging different approaches by DNOs towards non-firm connection arrangements to avoid needless network investment or reinforcement on constrained parts of their networks (See Box).
- **RIIO ED1 incentive on generator connection engagement and out-reach** – (and prospect of penalty for non-compliance). Ofgem seeking flexible innovative solutions to reduce customer costs (e.g improved information & data - heat-maps ; outreach with local authorities ; quality of service ; timely connections – both large and small DG customers).
- **New Losses duty** - and prospect of licence breach for non-compliance (para 5.27)

[112] Ofgem. 26/13. Strategy decision for the RIIO-ED1 electricity distribution price control. Overview. March 2013. Paras 2.13 & 2.14

16.2 Ofgem – Demand-side initiatives to improve 'local match'

- **New losses duty** and new discretionary reward (up to £32m) for 'efficient and innovative loss reduction initiatives'. Ofgem notes that system losses are the largest component of a DNOs carbon footprint. Potentially, could be used to encourage firm means of peak-demand reduction – shifting or permanent (e.g via automation as an effective means of loss reduction).[113]

- **Incentives in ED1 which may serve to support active local matching / self-balancing**

The following incentives in ED1 would *in combination* seem to support active steps by the distribution networks to promote local matching / self-balancing – especially as many of these incentives could also incur penalties for non-compliance.

- **Losses** – new Licence duty (paras 5.27-8) & £32 m discretionary award for 'efficient loss reduction'.
- **Connections** – incentive on connection engagement (5.38)
- **Social obligations** – to use relationships and build partnerships with other stakeholders to identify and deliver solutions (both energy and non-energy) for affordable energy – and for which a discretionary award may be available (5.43)
- **Environmental reputation reporting**
- **Innovation funding** – LCNF to end of DPC 5 in 2015. Network Innovation Competition from 2015). (7.00).
- **Innovation Roll Out Mechanism** – where innovation projects prove that a new technique or practice can lower costs or help the DNO to better meet its outputs, the DNO will be incentivised to realise those savings via the *efficiency incentive* which allows the DNO to share the benefits with consumers. Additional funds maybe available if innovation meets defined environmental criteria for carbon or other benefits) (7.12).

Smarter Markets Programme – routes to market for DSR and settlement reform (not explicitly focused on location).

DECC / Ofgem Smart Grid Forum (SGF) Work Stream 6 - is considering detailed regulatory and charging impacts for the networks of distributed generation, micro-generators

[113] ED1 paras 5.25 & 5.28.

See footnote 74. 'Firm' peak reduction may in principle create more network head-room and so reduce losses – but more intensive network usage could also increase electrical resistance and so increase losses.

and the demand-side. Work stream 6 has made some working assumptions to help inform their work on DSR. Ofgem's summary position is noted in the two boxes below.

Extract from Ofgem summary note on Work Stream 6 assumptions on network charging treatment of DSR[114].

1. That where existing domestic customers trigger costs through increased load or generation, that these costs are socialised.
2. Even if costs are socialised, there will be benefit in DNOs receiving notification of where heat pumps, EVs and micro-generation are installed at domestic properties.
3. That a market model for DSR will not develop in time for the start of RIIO ED1.
4. That DNOs are free to approach any customer, including domestics to sign bilateral arrangements for DSR.
5. That there will need to be some measures in place to preserve value across the value chain including allowing customers to withdraw from DSR contracts with DNOs if other parties can offer greater value.
6. That the methods and techniques for DSR will differ by customer group and whether the customer is new or existing.
7. That there will be no compromising current reliability and security standards which the network must meet.

[114] Ofgem. Withdrawal from DSR arrangements. www.ofgem.gov.uk/publications-and-updates/withdrawal-dsr-arrangements. 1October 2013.

Extract from Ofgem note regarding regulatory treatment of Energy Demand Reduction (following Work Stream 6 discussions)[115]

Simply installing energy demand reduction measures in customer's premises may not have the effect of reducing load and creating capacity on the network in isolation. Any contractual arrangements entered into by network companies would need to ensure that electricity demand actually reduced otherwise they may not deliver the required network capacity.

Incentives and innovation.

DNOs are incentivised to deliver a set of predefined outputs as efficiently as possible. One way they are incentivised to do this is through an efficiency incentive. This encourages DNOs to be as efficient as possible with their allowance which was set at the price control (known as the ex-ante allowance).

The effect of the efficiency incentive means that where a licensee makes a saving against their ex-ante allowance [1], it gets to keep a proportion (currently around 50 per cent of the saving, with the remainder being returned to consumers. Equally, if DNOs overspend against their ex-ante allowance then they must fund a proportion (currently around 50per cent themselves) with the remainder being funded by customers.
Consequently, if energy demand reduction measures represent the most efficient means of resolving constraints on the network, then DNOs will be incentivised to use them and make gains against their allowances under the efficiency incentive.

It has been suggested that DNOs would benefit from trialling the impact energy demand reduction measures can have on their network. This will help them understand the extent of the 'rebound effect' and whether energy demand reduction is a useful constraint management tool. We have asked licensees to give us examples of the types of energy demand reduction measures they would like to trial. The majority of the examples provided would not be eligible because they would fail to meet the criterion which states that the method being trialled must have a 'direct impact' on the network. This is defined as something which would have an observable and controllable impact on the distribution system. In addition energy demand reduction measures would not be installed 'on the distribution system' and they may not be considered controllable. We have consulted on allowing DNOs and other network licensees to trial energy demand reduction measures under the Network Innovation Competition (NIC) and the Network Innovation Allowance (NIA) and these governance documents are available on our website. The latest draft of the LCN Fund governance document is currently open for statutory consultation and would allow energy demand reduction measures to be trialled.

continues /….

[115] Ofgem. Role of DNOs in relation to energy demand reduction. www.ofgem.gov.uk/publications-and-updates/role-distribution-network-operators-dnos-relation-energy-demand-reduction. 1 October 2013.

Extract from Ofgem note regarding regulatory treatment of Energy Demand Reduction (following Work Stream 6 discussions)[116] (continued)

Working on the customer side of the meter

There have been comments that DNOs are not incentivised to work off the distribution network to deliver energy demand reduction solutions. The regulatory approach is increasingly about delivering outputs. Through equalising the incentives and moving to a totex approach, DNOs are revenue neutral to how they deliver their outputs. If they can deliver them more efficiently through working with customers and installing infrastructure on the customer side of the meter, then there is nothing to prevent them from doing so. Since DNOs are not currently customer facing businesses, there seems particular merit in them contracting with third party providers of energy demand reduction measures to realise the benefits of these activities for the networks.

Other sources of funding for energy demand reduction

As well as contracting with third parties, DNOs could work to raise the profile of other energy demand reduction schemes amongst customers on its network and facilitate participation in energy demand reduction schemes such as:

- **the Carbon Emissions Reduction Target (CERT)** – which requires all domestic energy suppliers with a customer base in excess of 250,000 customers to make savings in the amount of CO_2 emitted by their customers.
- **Community Energy Saving Programme (CESP)** – which targets households across Great Britain, in areas of low income, to improve energy efficiency standards, and reduce fuel bills.
- **Energy Company Obligation (ECO)** – which is the Government's new domestic energy demand reduction programme designed to replace the existing CERT and CESP programmes, both of which come to a close at the end of 2012. ECO will introduce three targets to use energy heat more efficiently.
- **The Green Deal** – is a financial mechanism which eliminates the need to pay upfront for energy demand reduction measures and instead provides reassurances that the cost of the measures should be covered by savings on the electricity bill.

[1] This is the up-front allowance set in the price control which network companies can recover from customers to deliver their outputs.

[116] Ofgem. Role of DNOs in relation to energy demand reduction. www.ofgem.gov.uk/publications-and-updates/role-distribution-network-operators-dnos-relation-energy-demand-reduction. 1 October 2013.

17 Distribution Networks – initiatives to improve 'local match'.

Incentivised initially by DPCR 5 TOTEX and LCNF - and now by RIIO-ED1 - the distribution networks now have a substantial number of initiatives in hand to recognise demand-side and distributed generator physical impacts at particular locations on their networks.

17.1 **Distributed Generation – DN initiatives to improve 'local match'.**

- **Better knowledge of DG via better information and data** – DNs are starting to obtain and collate better information on DG - via new requirements on notification (G59/2 / G83/1-1) and now also, post-installation, for micro-generators and small PV too[117]. Ofgem makes clear their wish for DNs to maximise benefits they can achieve 'from all forms of data that they have access to – including – but not limited to, data from smart meters – to lower network costs'[118].

- **Technical regulation to improve some of the physical impacts of small generators on the networks** – current revisions to G59/2 & G83-1-1 will help to address some of the 'non-regulated' technical disturbances which small generators may cause on the networks. Similarly, the European Network Codes[119] and ROCOF discussions[120] .

- **Installing new electronic monitoring and control equipment & developing new approaches to automated network management –** at particularly constrained network

[117] Sustainability First. GB Electricity Demand project. Paper 6 : 'What demand-side services does Distributed Generation bring to the electricity system ?'. January 2013. Identified that poor information on DG despatchability, output, and location was problematic for efficient distribution network management – and potentially, at scale, ultimately for the system operator and transmission boundary flows.

[118] Ofgem ED1 – para 2.27

[119] **European Network Codes (ENTSO-E)** are being progressively adopted on technical requirements for generation and load connected to the distribution networks throughout the EU. For micro-generators this introduces levels of smart / automated protection equipment down to installations of ~800W – so, capturing all PV installations and other types of generation. Current revisions to G59/G83 do not yet fully reflect the full provisions of the EU Code (but will do in due course). Micro-generator manufacturers are also being informed about the EU Codes so that they build-in the new technical requirements. (Email exchange with Mike Kay. ENWL & Chairman. DECC / Ofgem Smart Grid Forum Work Stream 7).

[120] **ROCOF Review** – (Rate of change of frequency). Technical review in Spring 2013 by Distribution Code and Grid Code Review Panel of operational parameters for small generators - for frequency management and for operational stability in terms of fault 'ride-through'.

locations, deploying new electronic monitoring and control equipment, new automated network management systems, more sophisticated voltage control (see box below).

Automated Network Management.

Smarter network approaches aim to make better / more efficient use of existing network assets –i.e. to obtain more network 'headroom' – rather than assume new network re-inforcement or investment. This means new approaches to manage these assets *within* the network design and operational requirements – while taking advantage of available latent thermal capacity[121].

Several DNs are trialling (LCNF and other projects) Active Network Management schemes of varying ambition level. For example : UKPN Flexible Plug and Play ; Northern Power Grid - Customer Network Led Revolution ; SSE NINES project ; WPD – Lincolnshire Low Carbon Hub.

The ANM being trialled ranges from the very sophisticated to the very simple[122].

ANM can also take account of the load on the system at the same time – and match generation and demand.

[121] For example, WPD Lincoln Low Carbon Hub combining : dynamic line rating ; network enhancements ; new commercial agreements ; FACTS (flexible equipment) ; dynamic voltage control ; 33 kV active ring. WPD slides for Ofgem Community Energy workshop. 4 September 2013.

[122] For example, seeking to control solar and wind output on the same network loop differentially, depending on their output at different times of year.

- **Engagement** - Distribution Networks are also taking active steps[123] to inform distributed generators about which locations are constrained and less constrained in terms of their prospective connections, including producing so-called Heat Maps to show significantly constrained areas. Distribution networks are meeting with local authorities, community groups and other stakeholders, aiming to tie together early stage discussions about local authority planning, network development plans etc.

- **Trialling new contractual approaches to non-firm connection** – Distributed generators over >3.68 kW increasingly can speak to a Distribution Network about where it is best in terms of constraints on the network to locate. Generators are increasingly needing to make trade-offs between connecting at a constrained or a less-constrained part of a distribution network. For example, some LCNF projects are piloting a range of non-firm connection agreements, some of which are very innovative. For distributed generators these offer a choice between : connecting at a constrained location in return for non-firm access to the distribution network *at that location* for their power output – in return for a lower connection cost. Or, choosing to connect elsewhere, where the network may not be constrained. The cost of the connection assets at another location could either cost more – or could cost less - depending on the network reinforcement required. 'Merchant' distributed generators may be in a position to make these trade-offs. ***Local or community groups may not*** (eg WREN, Wadebridge, WPD) – and so may have little choice other than to accept a non-firm connection agreement (and which as a knock-on may potentially create a somewhat less bankable project). (see box below).

[123] ED1 Output on Stakeholder Engagement

UKPN Flexible Plug and Play project. March Grid.
Non-Firm Connection Agreements[124]

Active Network Management facilitates *lower cost connection offers* by enabling the distributed generator to connect on a non-firm interruptible basis.

The March Grid distribution transformer, on the Eastern UKPN network, was not designed for distributed generation connections or bi-lateral flows and due to the local volume of new renewable generation connections, is at its formal technical design limit (n-1) for three types of network constraint : reverse power flow ; thermal ; and, voltage. The design standard (n-1) assumes 'worst case' i.e. that all generators are injecting power at full output, and no load is being consumed (eg a windy summer night).

A non-firm connection offer enables a distributed generator to connect *nearer* to March Grid – and so save on the cost of network reinforcement (e.g a greater length of new distribution line would be required, should they connect slightly further away).

The non-firm contract allows automated management of the distributed generators output by the DNO. Automated Network Management technology allows constant monitoring / measuring of the constraint (be that reverse flow, thermal or voltage) and allows the DNO to remotely reduce / constrain the distributed generator output whenever the constraint is active.

A great deal of time and effort in the trial is devoted to development of commercial agreements / contracts which will be attractive to distributed generators, and to reassure them that they still have a bankable scheme, a predictable revenue stream etc.

Distribution networks - trialling a variety of non-firm agreement types.

Distribution networks are putting considerable effort into trialling different commercial approaches to agreements for non-firm connection to explore what may work best for generators. For example : 'first-in-last-off' (potential bankability problems for the last-in) ; shared curtailment approaches (to avoid bankability problems) ; connection window at a particular location (effectively an auction) ; pay-as-you-go (WPD).

Non-firm connection agreements may need consideration in how far they also support demand-side 'matching' at the local network level, including whether being constrained off may unintentionally inhibit supplying *local* demand, including supplying local storage at times of high wind.

[124] Adriana Laguna. UKPN Presentation. Ofgem Community Energy Workshop. 4 September 2013.

17.2 **Demand-side – DN initiatives to improve 'local match'.**

- **Technical Revisions to P2/6** (Engineering Recommendation). For example : the contribution which firm DSR or storage could make to avoiding new investment and not compromise security of supply – are presently not necessarily 'recognised' in the current P2/6 security of supply standards. A technical revision to P2/6 regarding DSR and storage, may allow the distribution networks to take more explicit account of local and / or community-level DSR in future network design and investment. The need (or not) for such a revision is currently under discussion among DNOs.

- **New loads : requirements for better visibility / information / notification** – for large new loads eg heat pumps (National Terms of Connection - & discussion with ENA on notification)[125].

- **Bilateral demand-side agreements** – eg bilateral payments for pre-& post fault management. Also, increasingly, for electricity demand reduction at peak for constraint management, as well as in seeking to reduce losses[126].

- **Local / community initiatives to reduce peak and electricity demand at a particular location** – which aim to create network or transformer 'head-room' - and so defer network investment (eg ENWL - Stockport[127] ; SSE Community EDRP Scheme ; SSE LCNF 'Save' project ; UKPN VCEE project (see Part IV).

[125] Small-scale generation connections must be notified post-installation[125]. An equivalent notification requirement presently does not exist for connection of new loads (HPs, EVs). The ENA is understood to be discussing a possible notification process with BEAMA and DECC

[126] UKPN Business Plan. Annex 7. Losses Strategy. July 2013.

[127] ENWL Business Plan. Annex 9. Vulnerable Customer Strategy. Pp 13-14. Refers to the feasibility study by National Energy Action and Sustainability First to evaluate the potential for load reduction measures to be implemented in an area of Stockport served by the Vernon Park primary substation (one aim being to support reduced peak electricity of up to 2MW) and to help the fuel poor served by the substation and mitigate need for network reinforcement.

ENWL CLASS project – demand reduction by voltage control at a local electricity substation

Electricity North West's CLASS (Customer Load Active System Services) project began in 2012 and will run to 2015. This is a DNO-led project to reduce peak demand. The project uses automated voltage control at 60 primary substations, inter al, to reduce electricity consumption at peak times, without a discernible impact upon customers' supply[128].

The project aim is to increase the head-room capacity of the local electricity network using smart voltage control at major substations, which links to ENWL's control room – and thence to National Grid.

The ability to manage peak demand in this way may offer a useful tool to : offset increase in peak demand at a particular location ; defers or avoids network and substation investment ; reduces costs for all electricity consumers from reduced losses ; is potentially highly replicable.

On the face of it, this project would seem to overcome a main challenge faced by the distribution networks in not having a direct relationship with customers – because it does not require direct engagement with or involvement by customers – but instead, effectively works at substation-level like a giant dimmer switch. The project involves discussion with customer focus groups and customer surveys to explore customer views on any perceived effects on their electricity supply.

Interestingly, a recent report by London Economics for DECC, concludes that voltage reduction does not create a 'cost' to customers in terms of impact on appliances or other lost utility[129].

[128] The CLASS project is also trialling voltage reduction to provide frequency response services to the system operator and reactive power absorption to address high network voltages.

[129] The Value of Lost Load (VoLL) for Electricity in Great Britain. Report for DECC. London Economics. July 2013. P.51

17.3 Facilitating Matching of Local Supply & Local Demand – Distribution Network 'Business-as-Usual' ?

While the many trials and pilots are very helpful, a main aim for both Ofgem and the distribution networks during RIIO ED1 is to take forward major lessons emerging from the trials into 'business-as-usual'. In this regard, it will be important to tackle some of the administrative, regulatory and commercial barriers already touched on in section 3 and in Part II of this paper, to make this a reality.

Also, smart meters and eventual half-hourly settlement will be necessary before local supply and local demand matching can develop at meaningful scale as well as to overcome some practical obstacles to DNO-led DSR[130] - and, not least, to successfully target network management arrangements with customers and / or communities for *direct load-control at particular locations*.

[130] e.g to enable price signals, including ToU ; better data on consumption patterns (dependent on satisfactory arrangements for the networks to access the data); potentially enable direct load control

Part IV – Local / Community Demand-Side Case Studies – what the electricity system means to them

Section 18 explores six local / community electricity demand-side case studies.

Section 19 concludes with a general discussion of practical lessons – both from the case-studies and from a literature review - likely to be helpful to market actors or others with an interest in developing local or community electricity demand-side initiatives – especially those with an interest in engaging local groups and communities in provision of *firm* demand-side services as a possible alternative to network and / or supply-side investment.

18 Six Local / Community Electricity Demand-Side Case Studies

These case studies consider what benefits local or community demand-side activity might bring to the electricity system. Each case-study considers :

- The efficiency benefits of the scheme to the local electricity system.
- Who drove the scheme, the incentives offered - and the community response.
- Key factors in shaping the community response – and how far these may support an enduring and sustained response – and / or be replicable.

Case-study 1: Self-contained island balancing (peak reduction)
Isle of Eigg

Case-study 2: Overall electricity demand reduction at local substation
Community Competition for Energy Demand Reduction. SSE EDRP.

Case-study 3: Committed local community
Ashton Hayes

Case-study 4: Location-specific I&C demand turn-down scheme
Thames Valley Vision . SSE.

Case-study 5: Community self-balancing: wind to storage heaters
Nines Project. Shetland. SSE (Northern Island New Energy Solutions)

Case-study 6: Private wire : self-balancing
Community Energy Scotland

CASE STUDY 1 : SELF-CONTAINED ISLAND BALANCING (peak demand reduction)

Isle of Eigg[131]

Partners involved (and lead partner): Eigg Electric Ltd

Nature: Ongoing community owned commercial arrangement

The Isle of Eigg is situated in the Inner Hebrides, off the west coast of Scotland, and is reachable only by ferry. It is a community of about 100 people (53 households and 22 businesses) and has a long history of self-sufficiency and resource conservation, due to the expense of importing items from the mainland.

In 1997 the residents, the Highland Council and the Scottish Wildlife Trust formed the Eigg Heritage Trust and bought the island, previously owned by a succession of landlords. A subsidiary of this trust, Eigg Electric was set up to manage electricity use on the island.

Up until 2008 the island was powered by individual diesel generators as there was no inter-connector to the mainland grid. The community took the decision to set up its own grid which was turned on in February 2008, predominantly powered by renewable sources, including a 100 kW hydro turbine, 2 x 5 kW hydros, a 24 kW wind farm and a 50 kWp solar photovoltaic array. It has central batteries and diesel generators as back up.

At the same time as setting up generation it was realized that demand needed to be managed to regulate the grid. The community explored a number of ways of managing demand, including various forms of tariffs. Their solution was one that was thought to be the most equitable. It is as follows:

- Instantaneous power on the island **is capped at 5 kW per household and 10 kW per business.** Usage over this limit trips a switch cutting off the power and the maintenance team must be called to switch it on again. Individual fines of £20 can be levied (although none have been levied to date);
- All households have an OWL monitor which displays current and cumulative use and sounds an alarm when consumption reaches a certain level;
- Red and green lights are displayed in a central location warning the community when renewable energy generation is lower than demand, and when diesel back-up generators are operating.
- Excess power is used in fan heaters in community buildings.

[131] Information taken from from interview with Maggie X, Eigg Electric and Case Study for Ashdon Awards

In addition household energy use has been reduced through improved insulation in 40% of homes, more efficient multi-fuel stoves, and 20% of houses now have solar water heating. Much of this work has been funded through various grant funding opportunities and via participation in Nesta's Big Green Challenge.

When the electricity grid was constructed, residents paid £500 each for a 5 kW connection and businesses paid £1,000 for a 10 kW connection, helping to fund the installation costs. There is a daily standing charge of £0.12 for a 5 kW connection and £0.15 for 10 kW, but all users pay the same rate of £0.20/kWh used. Average annual electricity use per household on Eigg is just 2,160 kWh, compared to a UK average in 2013 of 3,200kWh[132]. Domestic carbon emissions have fallen by 47%, from 8.4 to 4.45 tonnes/year. This compares to average UK household emissions of 5.5 to 6 tonnes/year.

Eigg Electric Ltd is now exploring new renewable energy generation options to avoid using the diesel back-up generators too often. They have already increased the capacity of the PV units following a realization that the PV units are the most consistent during periods in the summer months when there is little wind or rain. They have an ongoing partnership with Dundee University and may form part of a tidal generation pilot.

Value generated to the utility and community

Being a stand alone system, run by a community energy company, any benefits accrue only to the community, as the utility is by nature also the community. By managing demand Eigg Electric Ltd can control its use of back-up diesel generators which come on if the central batteries get too low. The cost of running these generators is almost double the cost of unit charged per household (costs 40p unit compared to 21p unit charged). As the company is owned by the community ultimately the householders would end up paying this charge. The negotiations and running of this system have created a community that works together and brought significant social benefits, for example better treatment of drinking water and the elimination of the constant hum of generators. The ability of householders to keep their homes warm affordably has had knock-on health benefits.

In terms of economic impact, the electricity grid employs six part-time maintenance jobs. A wider economic impact has come from having a reliable and affordable electricity supply, which has enabled several new businesses to start up, including restaurants, shops, guest houses and self-catering accommodation. As Eigg has become known for cutting carbon emissions and protecting the environment, visitors have come to the island to learn about its work, bringing a further economic benefit to the residents.

[132] Ofgem, July 2013. Review of typical domestic consumption values

Longevity and replicability

As this is the only current way that Eigg can cost-effectively manage its electricity supply and demand, the project will continue for the foreseeable future. The island is looking at piloting new renewable technologies to support the development of new technologies and to increase electricity output if any population increase demands it.

There has been a huge interest in Eigg's system from other countries looking to replicate it for their island communities and they regularly have visitors to explore how it works.

Although it is likely that running a community electricity grid powered by small-scale generation is only directly replicable for similarly isolated communities, who are not connected to any main grid, there are lessons in demand management that can be learnt. However in looking at the issue of demand management a number of particularities about the Eigg case need to be kept in mind. These are:

- The size of community involved (53 households), meant that interaction, and agreement, between the households can be reached far more readily than in most UK villages or towns. Due to the island's isolation there is already a higher degree of sociability between neighbours, who are more dependent on each other, than in most communities.
- The high cost of diesel generation, which the householders used previously, meant that householders had a very high awareness of the energy consumption of individual appliances. This made it far easier for them to stay within their 5kW limit.
- The penalty of disconnection for too high energy use is currently not contemplated on the mainland.
- The high- cost of interconnection to the mainland combined with the cost and inconvenience of diesel generation meant that the community needed to come up with a solution. The resulting demand-side limits are the trade off for having a constant electricity supply.
- The community came up with its own solution for limiting demand, which meant strong 'buy-in' in to the methodology. This would be difficult to implement if a separate national supplier was involved.
- The visibility of power generation, both because the community can *feel* when the wind is blowing, or it is sunny, and via the red and green light system meant that the community can easily be responsive to days when there is greater or lesser power.

CASE STUDY 2 : OVERALL ELECTRICITY DEMAND REDUCTION AT LOCAL SUBSTATION

Community Competition for Demand Reduction. SSE EDRP[133]

Partners involved: Scottish and Southern Energy plc (SSE) with North Leigh Energy Efficiency Project, South East Wales Energy Efficiency Agency and Alyth Environmental Group.

Nature: Energy Demand Research Project trial run by SSE.

In 2007, Ofgem announced the participants of the Energy Demand Reduction Project (EDRP), a Government-initiated research project which was part-funded by Government. The bid from Scottish and Southern Energy plc (SSE) was unique in that it included *community trials*. These community trials would use similar interventions, including some smart meters, but focus on energy reductions from whole communities instead of individual households with the objectives of understanding community-level interventions, gaining experience of the means to reduce electricity demand over a 2 year period.

The objectives of SSE"s community trials were to:

- Test the effect of community involvement on behaviour and electricity demand reduction;
- Gain experience of methods to reduce consumer demand of electricity;
- Gain experience of methods to reduce peak demands for electricity;
- Test the feasibility of making a sustained reduction in demand across a whole community, and
- Encourage the community to make proposals for saving energy.

[133] This case study is an abridged version of the longer case study on the SSE EDRP community trials authored by Dr Megan McMichael, University College London, based on her PhD research, which we publish as a separate document in Annex 2

Three communities were selected for SSE's community trials, in different geographic areas. Criteria for selection included:

- A village served by a limited number of electricity substations, suitable for the installation of metering equipment;
- Absence of large loads that could mask changes in domestic demand;
- Community organisations that were receptive to taking part in the trial or a willingness to create such a group.

SSE chose three rural communities: the village of North Leigh (in Oxfordshire, England), the village of St Athan (in Vale of Glamorgan, Wales) and the small town of Alyth (in Perthshire, Scotland).

SSE set a target for each community to reduce their electricity consumption by 10% over a two year period. This target would be measured at the sub-station level, comparing a similar three-month period of electricity use at two points of the intervention (i.e. at the start and 2 years later). The award for reaching the target would be £20,000 for each community. Each community was to decide how to allocate the prize money, but generally it was expected that it would be used for community energy projects.

The efforts to achieve the 10% reductions were led by the community groups, with support from SSE. In parallel, and in conjunction with, the community group programmes, SSE rolled out a number of interventions. These included:

- Real time metering of electricity substations;
- Feedback of energy consumption information to the communities via a range a media (including website, local newsletters, local media, notice boards and electronic display);
- A focused campaign to provide energy efficiency information and advice to the community, backed up by grants for demand reduction measures;
- An incentive reward for the communities to save energy.

Other than the set of consistent interventions described above, communities were given a free rein to pursue their targets[134]. It rather quickly became evident that the schedule of interventions would need to be tailored to each community. Beyond the introduction of smart meters other interventions included *inter alia* insulation offers, either free or at discounted prices; vouchers for A-rated appliances; free compact fluorescent light bulbs; infrared thermal imaging of homes in some communities; free in-home energy displays.

[134] See McMichael. Annex 2. Section D4

The effectiveness of the interactions between the DNO and the community and the amount of final reductions varied between each community.

- **North Leigh :** a village in West Oxfordshire of 800 households, working with the existing energy reduction group, North Leigh Energy Efficiency Project, SSE helped the community reduce their energy a variety of community run activities and a sustained SSE presence involving door to door advice and weekly surgeries. North Leigh achieved its target of a 10% reduction in electricity use and was awarded the £20,000 prize money. The target was measured by comparing substation meter readings between December 2009 and February 2010 to the same months in 2007 and 2008. Additionally, a sample of households in North Leigh showed higher reductions in electricity consumption as compared to control groups of SSE customers in nearby areas. The prize money was used to install photovoltaic panels and an air source heat pump in the Memorial Hall.

- **St Athan :** a farming village in Wales of 450 households. There was no previous history of energy efficiency activity and SSE helped create 'Get Smart with St Athan', with initial help from the South East Wales Energy Agency. The group, alongside various SSE employees carried out activities, often piggy-backing on other local events but often did not get that high a take-up. St Athan did not meet its target of 10% reduction at substation, as compared to a baseline of 2 years previous, even though it did have lower electricity consumption in a sample of homes as compared to a control sample of SSE-supplied homes in the neighbouring area. The group was awarded half the prize money, £10,000, for what it did achieve and the efforts made. This money was used to help fund a new energy efficient boiler for the village hall.

- **Alyth :** a small town in North Scotland of 1,400 households. SSE worked with the Alyth Climate Action Town group to spearhead the Alyth Energy Challenge. During the community trial, the town also successfully made a bid to the Scottish Government for the Climate Challenge Fund. With this funding, the group began a'street-by-street' insulation campaign. Focus groups indicated that the Alyth Energy Challenge group thought that the Climate Change Funded 'street-by-street' campaign may have made a bigger impact than the SSE-backed initiative. However, information from a small focus group with residents indicated that householders may not have viewed the two initiatives as different, but rather as one campaign. Alyth reached their 10% reduction target, as measured at sub-station level. They were awarded £20,000 most of which was donated to the Boy Cubs & Scouts and Girl Brownies & Guides. The Boy Cubs & Scouts used their portion of the prize money to insulate the scout hut and install a new boiler. The Girl Brownies & Guides used their portion to help re-build the Guide hut. Since the end of the trial, there have been no further community-wide energy efficiency initiatives or interventions in Alyth.

Technical Benefits

Limited technical details were available to us on the overall benefits of the project - including what a 10% demand reduction represented in technical benefits or avoided investment at each substation. Beyond lessons for engagement between an energy company and communities and the challenges and activities needed to bring about a measurable general demand reduction it is not known whether these trials brought any particular technical benefit to either the local grid or the system nationally. Also the reductions were *overall* reductions, rather than focused on peak energy use. Unfortunately there is no monitoring to show whether the reductions achieved during the trial period endured beyond the trial period. The trials were largely successful in meeting the pilot goal however.

Value generated for the utility

Value of energy reduction was shared with participants through the offered £20,000 prize money. It is not known what value this represented for the DNO in this location and how this amount was calculated.

Value generated for the community

All groups spent their prize money on extra energy efficiency in local community facilities or on local energy generation, thereby creating extra value for their community and an increase in overall energy efficiency in that location.

Longevity and replicability

The SSE EDRP project was part of nationwide energy demand reduction trials and therefore was by its nature time-bound. In terms of longevity, recent follow-up with the communities did not indicate that there are any ongoing energy demand reduction projects taking place. This is not unsurprising considering that the project was given a clear end-date by which savings had to be achieved.

In terms of replicability this trial indicated that engaging with groups *that are already formed* is likely to be a far more effective way of starting to engage communities in energy efficiency, rather than creating groups from scratch for this purpose.

For more detail on this case study see Annex 2 to Paper 10.
Community Case Study for Sustainability First - Community Demand Reduction at Substation. (SSE EDRP) by Dr Megan McMichael. University College London.

CASE STUDY 3 : COMMITTED COMMUNITY - EXPLORING HOW IT CAN BEST DELIVER DEMAND-SIDE VALUE AND LOW-CARBON

Ashton Hayes

Partners involved Scottish Power Energy Networks, EA Technology, Going Carbon Neutral Sub-Committee of Ashton Hayes, Ashton Hayes Community Interest Company and Parish Council, plus numerous smaller community partners.

Nature: Community-led research project with active DNO involvement

Ashton Hayes is an award winning village in rural Cheshire with an ambition to become the UK's first carbon neutral village. Since 2006 the village has achieved a measured carbon reduction of 23% by introducing behavioural changes towards energy usage. For its endeavours, educational activities and future aspirations Ashton Hayes was awarded a DECC 'Low Carbon Community Challenge' Award in 2009. The village has subsequently become an 'early-adopter' of several low carbon technologies including two substantial photo-voltaic generation schemes and the introduction of a community electric vehicle.

Scottish Power Energy Networks and EA Technology have come together with the village to support the community in getting a far better understanding of its electrical consumption. The project provides the following main outputs:

- It enables villagers to know how best to maintain the energy reductions they have already achieved, where and when additional energy reductions would be most useful to the DNO and the main opportunities for installing more renewable energy.
- It gives the DNO a better understanding of present behaviour on the network, including minimum and maximum loads and a far more detailed understanding of the impact of demographics and profiles. It explores the capacity of a committed community such as Ashton Hayes to accommodate and benefit from low carbon technology without further reinforcement.
- Lastly the project also enables better understanding of the need for communication between a DNO and its customers and in particular enables the local council to consider distribution network planning in its planning processes and and the implication of the location of new renewables generation.

Activities

In 2011 Scottish Power Energy Networks installed power monitoring instruments on the four secondary substations feeding Ashton Hayes. These enabled the measurement of the village's combined consumption and showed the contribution that distributed generation was making.

Data was provided to the community, in the form of community reports, on:

- The village's total consumption;
- The electricity consumption pattern of typical properties on a daily basis;
- Characteristics of household consumption at various times of the year;
- The contribution that community generation is making;
- The capacity for further low carbon technology on the network; and
- Particular areas for improvement.

Technically the project therefore enables the DNO to pinpoint where particular transformers may be overstretched and to ask the community to target energy reduction and low carbon energy installation in that area.

The data showed that the amount of generation that could be connected can be significantly increased by carrying out small changes to the network such as changing the taps position of the distribution transformers. The capacity available depends on the type of generation. For example, PV will only operate during the day when there is higher demand to absorb the generation on the same feeder preventing excessive voltage rise.

Further studies[135] highlighted the particular impacts on electricity consumption by community facilities such as the village shop. This highlighted when and where the highest consumption of energy in the shop arises (ie it uses more energy in summer than winter due to cooling devices and that electricity used overnight contributes to over half the energy bill). It also identified where the most significant savings could be made (ie by reducing use of air conditioning and changing the open display chiller for a fridge for example).

Value generated for the network operator

In terms of value to the distribution network there is no direct value that the project can identify as there has been no avoided investment. However the value in terms of learning has been significant.

Value generated for the community

Working with such a committed community meant that there was no additional incentive needed for the community to take part. However, the project has no doubt helped maintain the community's interest and engagement with energy issues. The community is now well informed about their energy use and can now take relevant actions for their own benefit and for general efficiency of the electricity system.

[135] Ashton Hayes village shop report July 2012

http://www.spenergynetworks.co.uk/innovation/ashton_hayes.asp

Longevity and replicability

The Going Carbon Neutral project at Ashton Hayes is set to continue, with the data the village has now received it can continue to improve and target both energy reductions and connection of low carbon technologies. Now the local council has a better understanding of the role of the network operator, they will take into account the impact of planning decisions on the network. In addition the techniques for a DNO in monitoring the LV network and collecting data are also replicable.

However it must be noted that Ashton Hayes is a very committed community and already had a very high degree of energy literacy and understanding, and the local structures to be able to engage with the DNO and act accordingly. More work would be required to engage with less organised communities but such approaches could still offer the potential for savings in the long-term for a network.

CASE STUDY 4 : LOCATION-SPECIFIC I&C DEMAND TURN-DOWN SCHEME

Thames Valley Vision (TVV)[136]

Partners involved: SSE Power Distribution, Bracknell Forest Council, General Electric, Honeywell, EA Technology and others

Nature: LCNF funded project.

This five year project is focused on the Low Voltage (LV) network and aims to demonstrate how electricity distribution networks can better serve their customers by understanding, anticipating and supporting their energy use as they move towards low carbon technologies. The project explores a mixture of analytic, technological and commercial solutions.

SSE approached the local Bracknell council as a location for this study as the area is quite representative of communities across the UK in terms of its physical network, demographics, mixture of affluent housing and housing association blocks and its wide range of local commercial businesses including HP, General Electric, Honeywell and Waitrose, whose headquarters are all based in this location.

The project started in January 2012 and involved an intense period of customer engagement: working with the council and the local chamber of commerce, running local events and drop-in sessions at the local Community Centre. It has installed 250 meters in private domestic properties and 100 substation monitors. 21 businesses also agreed to install demand-response systems. The project is now gathering data from these locations which it will continue to do until April 2017.

The aim of these systems is predominantly monitoring. Householders are not asked to make any specific energy reductions at any specific time. Some households will also receive an EMA unit, which stores excess electricity as hot water. For businesses the project is trying to find out more information about when energy is used, again no specific volume of demand reduction is asked for, although the demand-side system will be operating.

There were no incentives offered for sign-up, however businesses could see the learnings and therefore efficiency savings that they would achieve through the energy audits and efficiency programme, so were keen to be involved as a result.

[136] https://www.ofgem.gov.uk/publications-and-updates/new-thames-valley-vision-six-monthly-report-june-2013.

Value to utility

This project will enable the utility to understand how feasible it is to reduce the electricity load at certain times, to handle fault conditions and seasonable patterns in consumption. The Bracknell network is due to be reinforced, although that work is not imminent, so it also looking at what actions could be taken to benefit the network and avoid reinforcement. It will also look at the issue of 'bounce-back' once a demand-side intervention has finished and whether staggering is required to avoid a surge of demand. The intention is to build DSM into business as usual as a response to high demand in a location.

This project has also helped the DNO understand how to engage directly with customers and that the DNO needs to be more involved to understand customer energy use.

Value to community

In late 2014/15 SSE will explore various commercial propositions in terms of value. Some businesses that have international partners or networks declined to take part in the trial without receiving payment for their involvement, as similar international schemes have involved an associated payment. SSEPD is exploring how to calculate this payment - whether based on deferral of network reinforcement or location. Finally they are exploring payments based on providing extra time to the utility to explore what is the next solution for that location, giving them time to make that decision in an unrushed way. They are still considering whether, for example, to share the value with every customer or just those that are actively involved.

The base knowledge of the local community about energy issues has improved and their understanding has changed of who a DNO is and what they do.

Longevity and replicability

As Bracknell was chosen as a community to be representative of the UK, and not a particularly committed or engaged community, SSE hopes the results it receives will be fairly replicable elsewhere. The information that they have provided for local businesses in terms of ongoing demand reduction will hopefully be enduring, but as much of the rest of the project is based upon monitoring, it is unknown whether it will have any long-term impact on the community's energy behavior once the project has been completed.

CASE STUDY 5 : COMMUNITY SELF-BALANCING – WIND TO STORAGE-HEATERS

NINES Project. Shetland (Northern Island New Energy Solutions).SSE**.**

Partners involved: Led by Scottish & Southern Energy and brings together a number of organisations and funding partners including Shetland Islands Council, Hjaltland Housing Association, Shetland Heat Energy and Power (SHEPD), the University of Strathclyde and Glen Dimplex.

Nature: Ofgem initiated project

The Shetland Isles, 130 miles north of the UK mainland, are not connected to the main UK electricity network. They rely entirely on local sources of generation, with electricity mainly generated by the diesel-fired Lerwick Power Station (LPS) which is coming to the end of its natural life and will be decommissioned in 2017. There is no gas supply on the island, so heat demand is largely met by oil-fired boilers and electric storage heaters.

There is significant interest from wind generators to exploit the excellent wind resource on the islands. Up until now insufficient capacity on the local network, and insufficient demand to utilize the generation, has held back connection.

Scottish and Southern Energy (SSE), at the request of Ofgem[137], have initiated the three year NINES project to test a number of initiatives aimed at reducing the maximum electrical demand on the islands, thereby increasing the amount of wind generation able to connect, and enabling the existing power station to replaced with a smaller unit. The key entities they are working with are the Shetland Islands Council (which was initially a funding partner before dropping out of this role) and the Hjatland Housing Association which is liaising with tenants.

Peak demand on the island is currently 48MW with a total capacity at LPS is 67MW. Scottish Hydro Electric Power Distribution predicts that the NINES trials could deliver solutions that would reduce the capacity required from LPS's replacement by up to 20MW, with a 10MW interim target.

[137] Ofgem, 2011, Shetland Northern Isles New Energy Solutions (NINES) Project Consultation

Key features of the NINES project are:

- Installing 'smart' storage heaters and hot water tanks in up to 1,000 homes to help reduce peak demand and provide a more efficient, controllable system;
- Adding a new electric boiler to the existing district heating system in the capital of Shetland, linked to a thermal store and facilitate extra connections to the scheme;
- Deploying new technology on the network that will allow more small scale renewable generators to connect to the network;
- Introducing new commercial arrangements to encourage businesses to change the times at which they use most energy;
- Actively managing the network to ensure all the different technologies work together, and
- Installing a 1MW battery at Lerwick Power Station.

An initial trial was conducted with six homes to test the installation and use of the new smart storage heaters and hot water cylinders[138]. Housing Association Tenants were offered £100 per household to participate. This demonstrated the functionality of the system.

The original NINES submission plan included installations into 750 homes provided by Hjaltland Housing Association and Shetland Islands Council. However due to internal financial constraints, Shetland Islands Council announced in October 2012 that they would be unable to continue with the project. Unfortunately this meant the project lost over 500 domestic homes from the trial. Hjaltland Housing Association are still committed to the project and agreed to provide 234 domestic homes. The team has now decided to expand the offering of DSM beyond the social housing market as there had already been interest shown by private householders locally.

Roll out of the smart heating systems to a further 750 households is now underway, taking place at a rate of about one home a day.

A consultation is also underway to explore how best to reward private households for being part of the scheme to ensure the project can reach its 750 household target. The aim being to establish what the minimum necessary incentive is to create enough storage, yet continue to reduce the overall cost-burden on Shetland customers.

Value generated for the community

Housing association tenants are receiving the new heating system without any direct charge. Whilst private households will need to pay upfront for the installation of measures

[138] Scottish and Southern Energy, LCNF Tier 1 Close-Down Report: Trial evaluation of domestic demand side management, SSET1003

themselves, SSE is exploring rewarding them with a payment of around £200 per certified system installed. This amount is being tested with householders currently.

The project entails additional costs to all SHEPD consumers in the short term (of around £15m), with the expectation that these costs will be offset in the long-term by savings in the second phase of the plan and bring other benefits, particularly allowing more renewable generation to be connected in Shetland. As there are higher costs associated with electricity supply on Shetland, at the time of the fourth distribution price control (DPCR4) it was agreed that the cost differential should be recovered from all SHEPD customers[139]. SHEPD calculates that, in 2010-11, the additional cost of providing a supply on Shetland resulted in an average cost across all their customers of £27 per customer. The value of NINES is highlighted by the estimate that it would lead to a £16.67m reduction in costs compared to just replacing Lerwick with a like for like replacement. In term of costs for customers, it is estimated it will cost £29.35 per SHEPD customer compared to £31.97 per customer under the base case (retrofitting LPS)[140].

Value generated for the utility

The current arrangements to supply electricity on Shetland cost around £29m in 2010-2011. The majority of the costs are from the fuel and operating cost of running Lerwick power station (£16m) and the rest from third party contracts (£13m).The payment being proposed for private householders is based on the cost of avoided fuel at the power station, through a reduction in peak demand, through more renewable power and through avoided costs of batteries (approximate calculations indicate the cost of storing energy via domestic storage heaters is 25% that of utilising battery technology).

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[139] Ofgem, 2011, Shetland Northern Isles New Energy Solutions (NINES) Project Consultation

[140] Original benefit case:

https://www.ofgem.gov.uk/ofgem-publications/43538/shepdninesconsultation.pdf

Revised business case:

https://www.ofgem.gov.uk/publications-and-updates/decision-approve-changes-scottish-hydro-electric-power-distribution-shepd-plc%E2%80%99s-%E2%80%93-northern-isles-new-energy-solutions-nines-project

One challenge the project is facing is that there are presently not particularly strong incentives on customers to store energy for their own use or for export at times of high UK system demand or to avoid export at times of network constraint.

Longevity and replicability

This project, once installed, proposes to be a permanent alternative to replacing the existing power station with a similar or larger sized unit. The project has an end date for installation of measures, in 2017, based on the date for decommissioning. By this point it should be possible to see whether it will be successful at achieving its desired aims.

The project will generate valuable lessons that will be applicable to the other DNOs on the potential for local balancing and to the GB system operator with regards to active balancing of a system, the effectiveness of load-shifting to domestic-based storage heating systems and other demand-side management solutions.

Whilst Shetland has a particular location with no connection to the mainland grid it provides a microcosm of a constrained local network (or, at scale, the national system).

CASE STUDY 6 : PRIVATE WIRE - SELF-BALANCING

Community Energy Scotland

Partners involved: Kilchoan Community Association, Community Energy Scotland

Nature of study: Community run commercial

Below we detail a small scheme in a remote community in Scotland that has been working with Community Energy Scotland on local balancing initiatives.

Kilchoan Community Centre Wind to Heat scheme

The Kilchoan Community Centre is located in Kilchoan on the Ardnamurchan Penisula. It is an isolated village community of around 150 people. The community centre is the main hub for community activity in the village and these activities include: a community hall, fitness gym, tourist information centre, local café and local GP surgery. The centre also provides some employment locally, with one full time employee and several part time employees. In common with many community facilities, KCC was experiencing difficulty with the energy running costs for the centre.

Community Energy Scotland recommended a 'wind to heat' scheme, to take advantage of the electric storage heaters in the centre and the local wind regime and topography. The electricity generated from the turbines is used to heat-up storage heaters within the building and creates a positive heat gain rather than a negative heat loss which is the usual effect from wind exposure. When all the heaters are warm enough any spare electricity feeds lighting circuits first, via a private wire system, and, any excess spills on to the local grid network.

In general it is not possible to receive grant funding for installation costs and be eligible for Feed in Tariff payments. However because of the timing of the grant funding received for the project and the launch of the Feed in Tariff in 2010, the project was still eligible for the Feed in Tariff. Therefore the group receives an income from the FiT generation tariff and from deemed export payments under the Feed in Tariff system for unmetered spill.

Technical benefits

The technical benefits are purely local as the scheme is administered through a private wire. However there were a number of technical challenges in the first year of operation due to inverter problems, lightning strikes and other difficulties which meant that generation output was at just 16%.

Value to the community

The scheme cost approximately £72,000 to install two 5KW wind turbines and associated heat stores, monitoring, controls and wiring, most of which was funded by grant funding from the Scottish Government with the community providing 5% (£3607.75). Electricity bills for the average year cost £3200. In the first year of operation generation from the new turbines saved around £1,200 in electricity from the grid, augmented by feed-in-tariff payments of £3,920. The FiT payments were slow to arrange which caused problems for the community.

Value to the wider network

The value to the wider network is not known. It is not known whether there was any constraint on the network at this location.

Longevity and Replicability

This project has attempted to help a remote community pay energy bills for a community facility and increase local energy security. However it has come at a high overall cost, with a long pay-back and which was made possible with provision of generous upfront grant funding.

Because of the rules applied by Ofgem regarding FiT eligibility and grant funding, much of the grant funding that was used to make projects of this type viable is no longer available.

Working with the FiT scheme has highlighted the challenge that communities face when engaging in bureaucratic processes that do not always deliver proposed funding on time.

18.1 Other early-stage local projects on energy-balancing

In addition to the case studies that we have looked at above, there are many other GB projects, currently in planning or initiation phase that seek to explore the issue of local-balancing and demand-side reduction in relation to community activities. These projects should start to yield results over the next two-three years.

These include:

- **Community Energy Action - Western Power Distribution (estimated completion date 2014)**[141]. This project aims to determine if demand side response is effective for communities who have demand information and incentives available to them. Ten communities will be chosen, with a particular emphasis on communities that have high low carbon technology adoption (such as heat pumps, electric vehicles and photovoltaics) to increase understanding about how low carbon technologies change demand profiles and affect the LV network. Community level electricity network and energy flow data will be collected and shared with the community. They will also get local energy efficiency advice from energy charities. The communities will be incentivised to reduce demand at peak periods of the day to reduce potential overloading of the low voltage network.

- **Hook Norton - Western Power Distribution (estimated completion date end 2013)**[142]. This project plans to develop and explore customer engagement and incentive programmes, including a small scale domestic demand response trial. It will also develop community data measurement and display capabilities (e.g. to ascertain the total electricity consumption of the village by installing measurement devices at various locations) and provide this and other relevant information back to the local community via a web portal/customer interface.

- **SAVE project – Solent Achieving Value from Energy Efficiency – Southern Electric Power Distribution (SSE)**[143]**.** This new second tier LCNF project in the Solent area of the south east of England, plans to establish to what extent energy efficiency measures can be considered as a cost-effective, predictable and sustainable tool for managing peak demand as an alternative to network reinforcement. The project will involve domestic customers only, and the measures to be trialled will involve deployment of a technology, offering a commercial incentive, and an

[141] http://www.smarternetworks.org/Project.aspx?ProjectID=421

[142] http://www.energynetworks.org/electricity/smart-grid-portal/lcnf/tier-1/western-power-distribution/hook-norton-low-carbon-community-smart-grid.html

[143] https://www.ofgem.gov.uk/publications-and-updates/low-carbon-networks-fund-submission-southern-electric-power-distribution-%E2%80%93-solent-achieving-value-efficiency

innovative approach to engagement. The network aim is to have a suite of tools to assess a particular network's suitability to demand reduction from energy efficiency measures – and to inform investment choices between customer demand reduction as against traditional network investment, including smart solutions. The project will run for four-years plus, from January 2014 to June 2018.

- **Vulnerable Customers and Energy Efficiency (VCEE) – UKPN** [144]**.** This new second-tier LCNF project aims to support vulnerable customer groups and allow them to fully participate in DSR and energy saving opportunities, reduce their bills, access offers and play a small but socially important role in supporting the network. It will provide evidence-based learning on the extent that fuel poor can engage in DSR activities which can benefit the network in terms of deferred or avoided investment. The VCEE project will run in the London Borough of Tower Hamlets, which is characterised by a high penetration of fuel-poor electricity dependent customers in tower blocks owned by social landlords. There will be two trials for demand reduction and demand shifting. 550 households in two groups will receive smart meters, simple energy saving and energy shifting devices, energy advice and ToU tariffs. The trials will explore : the level of response from fuel poor customers to smart meter data and price signals ; energy cost savings achieved from customer interaction and network benefits ; improved demand profiling of these customers ; and the effectiveness of different engagement interventions. The project will run for four years from January 2014 to December 2017.

- **Stockport Energy Efficiency Project**[145] **-** Following a feasiblity study for ENWL by National Energy Action and Sustainability First to evaluate the potential for load reduction measures to be implemented in an area of Stockport served by the Vernon Park primary substation (one aim being to support reduced peak electricity of up to 2MW), ENWL is taking forward an energy efficiency project, targeted at the fuel poor in the area of Stockport served by that substation and to help mitigate need for network reinforcement.

[144] https://www.ofgem.gov.uk/publications-and-updates/low-carbon-networks-fund-submission-uk-power-networks-%E2%80%93-vulnerable-customers-and-energy-efficiency

[145] ENWL Business Plan. Annex 9. Vulnerable Customer Strategy. Pp 13-14.

19 Lessons from Local / Community Electricity Demand-Side Case Studies

Section 19 draws on the conclusions reached through our six case studies - and on relevant literature on community energy and demand-side reduction in GB – to outline some general lessons that could be instructive to utilities or government initiatives for future local or community interventions on the electricity demand side.

These lessons are divided into potential benefits and challenges.

19.1 Benefits and opportunities for community based electricity demand-side action

19.1.1 Communities who already have an interest in energy are easier to engage. However most of these are not actively engaging with suppliers or DNOs on demand reduction projects.

The Energy Saving Trust[146] (EST) has identified over 3,000 community groups in the UK that are actively engaging with energy issues. Most of these are primarily involved in awareness raising and behavioural change projects. The EST research found that the most successful groups are bound by more than an interest in energy saving. However the majority of these groups are not being engaged successfully by energy companies due to their reported mistrust of the industry and recent media stories over profiteering and a fear of being 'squeezed out' of programmes that they might put their names to.

Although very few of these EST reviewed groups appear to have been part of a project using smart meters or demand-side response, most had a desire for more detailed energy use data (as Lower Super Output Area or below on a monthly or quarterly basis) to help them identify the measures and sectors where they could have the greatest positive impact.

Existing community groups are generally more trusted on the subject of energy. During focus groups with EDRP participants there were general concerns that arose that residents sometimes did not trust energy advice from their energy supplier because, for example, as they believed it was not on the 'agenda' for the supplier to want to encourage energy efficiency. Other evidence suggests that electricity and gas suppliers are amongst the least 'trusted and impartial' of information sources on energy efficiency or demand reduction[147]. Community members have credibility due to previously established personal contacts which are relevant to the topic and can provide local help and 'handholding'[148].

[146] EST, *Role of Community Groups in Smart Metering-Related Energy Efficiency Activities*

[147] Castle 2010

[148] Murray et al 2013

Our EDRP case-study showed the difference in success rate between communities with pre-existing community groups interested in energy and one that had been brought together for the project by SSE. The latter, based in St Athan was the only one to not achieve the 10% targeted reduction in energy use.

19.1.2 Local balancing/matching of supply and demand may make it easier to engage people in local DSM as they can directly see/feel whether renewables will be working on a particular day.

One of the reasons that the community on Eigg find it easy to help use energy when it is available is to do with the visibility of the energy itself. As they are such a small community they can feel when it is sunny or the wind is blowing and can use energy at those times appropriately. In addition they have a very visible traffic light system which shows them clearly when wind or solar generated energy is high.

This means that energy production is far more salient to them than in the average household, where electricity generation is almost universally invisible. Communities are disconnected from power supplies which can be several hundred miles away.

This connectedness with the energy supply is an issue to be explored further with the development of tariffs matched to renewables production. It could cause problems, for example, if households are told to use energy when the wind is blowing yet when the wind is blowing in their area local wind is constrained off or the high wind corresponds with peak demand.

19.1.3 Working with communities can transform the role of the DNO

The operation of DSM changes the way in which DNOs or service providers need to operate. A good example can be seen in SSE's Active Network Management system in Orkney. Under traditional solutions the DNO may have laid a new interconnector to the island to allow the connection of more renewables, the customers would be connected and other than faults the customers would have little interest in the operation of the system as long as their generation was able to export and the lights stayed on. With new solutions like DSM and Active Network Management customers take an active interest in the operation of the system, they want to know why a turbine was constrained or why the DNO is charging the heater in the evening instead of the morning for example. This all increases the level of interaction between the DNO (or other operator) and the customer, changing the nature of the distribution business and their local partnerships. This is likely to be the case with the NINES project once more storage heaters are installed and active management starts to take place.

19.1.4 Working with community groups, and giving them a sense of ownership, is challenging but seems essential to secure action on the community scale.

The Eigg case study[149] clearly shows that when communities are faced with a problem and come up with a solution themselves they have far greater ownership of the solution and will invest more to make it successful. Ipsos Mori showed that panellists of householders when asked to imagine a solution to a constrained grid were not keen on any kind of restrictions on their usage, yet in Eigg the community came up with a solution that restricted usage to 5kW. This shows that a community-owned solution can be more ambitious than one imposed from the outside.

However all communities are unique and there is no one size fits all approach that is likely to work. Eigg has a very particular set of circumstances that allowed this solution to work for them. Other communities will have different solutions that are more suitable and acceptable.

The literature suggests that the benefits of pairing up with community groups are not simply due to utilisation of existing social networks. As Stern (2002) indicates, this approach is "most effective when [community groups] adopt the intervention as their own, perhaps adapting the message in the process to make it meaningful to their constituencies". In the EDRP project each community created a name and campaign for the initiative, were committed to the two year programme, and sought to inspire their fellow community members to achieve the 10% targets. Qualitative findings from the PhD research by Dr Megan McMichael indicated that residents largely trusted the local community group members.

People were just as likely to ask someone they knew for information on energy efficiency, as to approach an organisation (e.g. local council, EST) or use the media (e.g. internet, leaflets)[150]. Leaflets and websites will be important, but may only be useful for a fraction of residents when first looking for information; having local people on-hand to answer questions, direct queries, or just to discuss would thus be a benefit for those seeking information on local campaigns or specific energy-related questions.

19.1.5 Supporting community groups can enhance their effectiveness

Groups in the EDRP project appeared to benefit from their support from SSE and did not appear to particularly struggle for finance or other resources, such as information and advice, which other community groups promoting similar initiatives – but without support from an

[149] Eigg case study details

[150] McMichael & Shipworth 2013

energy company – have had problems with[151]. This does not mean that the community groups did not encounter any financial and other constraints, but the support was useful.

Likewise the information that Scottish Power was able to provide to Ashton Hayes has greatly enhanced the effectiveness of the local community in their efforts in demand reduction, as has the support that Community Energy Scotland provided for the Kilchoan Community.

19.1.6 There may be more scope for local balancing projects with isolated communities.

Many of our case studies were based in Scotland (Eigg, NINES and the Community Energy Scotland private wires project). Action has been driven in this area by increased network and distribution constraints and isolated small communities, combined with increasing resource for renewable energy, in particular wind.

It is in these locations in Scotland, and there are likely to be similar communities in the South-West of England, where local balancing and demand reduction projects may be more likely. This is for two reasons: first, they are likely to bring greater cost efficiency to the local electricity system and secondly, they are likely to have greater success.

Orkney[152] is another example of a local balancing project, however this is achieved through the UK's first 'smart grid' which rather than controlling demand, controls generation. It has enabled the same amount of renewable generation to be connected to Orkney's distribution network as would have been made possible by conventional network reinforcement at a fraction of the cost. Generators are instructed in real time to control their output to match available network capacity.

[151] (Lockwood & Platt 2009; Seyfang et al 2012; House of Commons Energy and Climate Change Committee 2013 2013

[152] Link to Orkney page on SSE

19.2 Challenges for local community balancing or local demand reduction projects

Below are some 'generic' challenges indicated by our case-studies.

19.2.1 Lack of expertise within community groups means – on the whole- communities are unlikely to initiate these kinds of projects on their own

Even where communities are engaged and committed, the effort necessary, know-how and energy to initiate and see through even a modest demand-side project is considerable.

The Energy Saving Trust's research[153] identified a number of gaps in skills within community groups that inhibited further action on energy and could continue to challenge projects that rely on community activity. These included: lack of technical knowledge and advice; lack of support in making appropriate promotional material; lack of online informational support; lack of time, difficulty in communicating consistent messages and lack of funding.

The EDRP case study exemplifies this point. The communities in these examples required positive and sustained support from SSE to be able to engage with local householders. Where SSE support fell short, due to changes in staff for example, the projects struggled.

The reason that the community on the island of Eigg[154] was able to be successful in initiating and managing its own large-scale community energy balancing scheme is primarily down to its particular circumstance. Firstly it is an issue of attitude: the islanders are cut off from many mainland services and therefore have developed an independent and self reliant attitude. Secondly, their previous method of energy generation (householder generators) was expensive which meant residents were far more energy literate than the average community as they attempted to keep their bills down. Lastly they were accustomed to working together and developing community-wide solutions.

The community at Ashton Hayes is equally a particular one. Ashton Hayes has styled itself on being one of the greenest communities in the UK and therefore already had high proportion of committed community activists knowledgeable about energy use. Whilst it is unclear who first initiated the project with Scottish Power it is clear that without the degree of commitment that Ashton Hayes showed the project may not have succeeded.

[153] EST, *Role of Community Groups in Smart Metering-Related Energy Efficiency Activities*

[154] See Case Study 1.

19.2.2 There is no incentive for communities to engage with demand side activity on a community level and no provision of information as to where demand side activity would be best placed.

The work done with Ashton Hayes, actively showing the community how their energy is used, where demand can be cut most usefully and how community level buildings impact, is highly unusual. Most communities do not have access to this kind of data, and even with the provision of smart meters it is unclear how readily they will be able to access this local-level data on a community rather than an individual level.

DNOs have been charged with producing maps showing where in the country there is potential for further connection of renewable energy into the grid. However there seems to be little similar work planned for the demand-side. As Green Alliance's recent report on community energy schemes highlighted[155] this means that it is hard for communities to envisage any financial benefit from engaging in demand-reduction activity and as a result demand-side projects are likely to be less attractive than initiating a community energy generation project for which they are eligible for a FiT payment.

19.2.3 Community groups that already have an interest in energy might not be located in a part of the network in which there would be value in localised balancing or demand reduction.

Further work needs to be done to explore where interested groups are located with respect to those parts of the network where localised balancing or demand reduction could have a real value. Projects are likely to be more effective where there is a congruence of an interested community and an electricity system efficiency need.

Currently a DNO may have a constrained part of the network, or a community may want to get involved in demand reduction, but the two have no means of connecting.

19.2.4 DNOs are not visible to the average community

A further challenges is the lack of visibility of DNOs to the average householder. Work by Ipsos Mori for Ofgem[156] showed that very few people were either aware of the role of network operators (DNOs), or had any relationship with their DNO. The Ofgem Consumer First panel showed that the image of energy companies is 'at an all time low' as a result of perceived excessive price increases and with households unable to distinguish between their

[155] Green Alliance report

[156] *Consumer priorities for electricity distribution network operators: Findings from the Ofgem Consumer First Panel Year 4: Third workshops (held in June 2012)*

supplier and network operator companies will struggle to engage householders without a mediator.

19.2.5 Working with third parties, and relying on consumer action, can be a challenge for DNOs who need a guaranteed solution to their network constraints

For a utility looking for a solution for network constraints it is far simpler to purchase a single asset or traditional engineering solutions and install it, "effectively fit and forget". DSM, and in particular achieving self-balancing, is a far more complex solution requiring interaction with markets, and understanding of the drivers that individual customers apply to their purchase decisions and an ongoing need after set-up to understand changes in the behaviour and choices that customers make. Not least it also requires an active relationship with customers.

Where a constraint is anticipated on the network there is a limited time until the constraint results in technical network problems. Normally, traditional solutions can be implemented in this time-frame. However reliance on DSM or local balancing as a solution requires changes to be made in a large number of properties. This takes time, not only for the physical implementation - but also for scheme sign up and recruitment and, in many cases, identifying funding for the provision of the appropriate DSM systems.

The NINES project exemplifies the challenges of working with third parties. The project has struggled to keep its timescale as a result of a key partner pulling out, which meant they also lost other funding.

The EDRP project shows the challenge of achieving a specific demand reduction in a particular location based broadly on customer behaviour change. If the DNO was relying on a 10% reduction in St Athan to defer or avoid further investment in the network, this would not have been achieved despite a great deal of interaction with the community. As a result the network upgrade would have needed to go ahead.

One potential solution is to ensure that where possible all future electrically based heating systems and other significant loads are designed and installed with demand side response in mind from day one in new homes[157]. If this were the case, then a DNO using DSM to provide a solution, would be able to activate the DSM-enabled assets under a pre-agreed market arrangement to reward the customer for the provision of that service.

[157] We will return to these innovation issues in more detail in Paper 11

19.2.6 **There is no 'one size fits all' approach**

The SSE EDRP case-study exemplifies this. SSE initially intended to systematically roll-out a series of interventions of smart meters, insulation offers, etc. However, technical issues with the smart meters and communication with the community groups made it evident that the interventions needed to be tailored to each community, particularly with regard to timings and the focus of the group activities. Once a more flexible focus and approach was taken, the community groups seemed to feel more comfortable. For example, in North Leigh, the focus was strictly on energy efficiency to start, but broadened to include wider environmental issues which the community group felt were particularly relevant to people in the area.

19.2.7 **It is unclear whether the projects we have identified as case studies that rely on active community behaviour change would be either persistent or replicable**

It is unclear for most of the case studies that involve active engagement or behaviour change on behalf of the community to produce demand side response, how persistent these actions will be. Most of the case studies we looked at were for time-limited periods only and it is unknown what happened once the projects ended.

Indeed even during the projects, momentum faltered. For example in the EDRP case study each community struggled during the latter stages of their project. Some felt they had done all they could do, or had reached everyone that was interested. But, sub-station readings still did not indicate the kind of reductions they were aiming for.

Regarding longevity the only information we have is from one of the EDRP communities where we have discovered that energy efficiency activity came to an end once the project ended. Real life often intervenes with ongoing behaviour change.

By contrast, for the Isle of Eigg the successful ongoing nature of the demand reduction can be deemed to be very specific to the location and circumstances of the island. It is unclear whether this would work in a community that was connected to the main grid.

19.2.8 Providing value for communities/ households who engage in DSM, based on avoided investment, is possible but it is unclear what the level would need to be to encourage action.

Most of the case-studies we looked at 'rewarded' local demand-side participation via a competition, equipment, or a one-off payment. Those incentives did not entail making a payment explicitly linked to the cost-savings of avoided investment which the DSR was expected to bring. Only the NINES project is seeking to link the calculation of the incentive payment to private householders to install storage heaters to the savings from the avoided investment (currently estimated as a one off payment of £100-200 per household – and estimated to be around one quarter of the cost of battery storage at today's prices). However this project has yet to begin, so it is not yet clear whether this payment will be sufficient to incentivise action.

For most of our case studies we are not aware of how value to be shared with the community was (1) calculated or (2) how it was shared, and (3) with whom. Reducing peak potentially delivers more value than reducing electricity demand in general. A lower peak may help avoid network investment plus may also help to reduce losses, and therefore has potentially more value.

19.2.9 Energy companies, Ofgem and others need to learn the emerging lessons from the many new electricity demand-side projects that are underway.

Far more case study material will become available over the next two years, which will contain valuable lessons. In particular on the realism of how the cost-savings which networks seek at particular locations can be matched with the capability of local neighbourhoods or groups to deliver demand side reduction on a sustained basis. It will also help indicate how suppliers and other third parties such as Local Authorities can themselves be identified to help and support targeted local action.

Annex 1

Distribution Codes

Key distribution level agreements, technical codes, rules and standards.

- DCUSA (Distribution Connection and Use of System Agreement). Both suppliers and distributed generators are signatories. Covers :
    - Common Distribution Charging Methodology (CDCM) for suppliers and distributed generators
    - Extra High Voltage Charging Methodology (EDCM) - for large distributed generators and large I&C customers.
    - Common Connection Charging Methodology – for distributed generators and large loads.
- Distribution Code – a code with which DCUSA signatories must comply (technical parameters for connection to and use of the distribution networks. Covers compliance issues on network operations and planning.
- G59/2[158] Engineering Recommendations for connection of a generator to a distribution network.
- G83/1-1– Engineering Recommendations **for Smaller Generators – effectively , 3.68 kW** (single phase) & 11.04 kW (three-phase). Sets out standards and guidance on technical requirements (under Distribution Code).
- ROCOF Review – (Rate of change of frequency). Technical review by Distribution Code and Grid Code Review Panel of operational parameters for small generators - for frequency management and for operational stability in terms of fault 'ride-through'.
- G81 – Principles for Connection[159].
- P2/6 – Security and Reliability Standards for Distribution Networks. Presently being revised to accommodate low carbon generation and new technologies.
- Electrical Safety, Quality and Continuity Regulations (ESQCR) 2006
- EU ENTSOE Demand Connection Code

[158] ER G59/2 : 'Recommendations for the Connection of Generating Plant to the Distribution Systems of Licensed Distribution Network Operators. Sets out the technical requirements which **larger** embedded generators must meet before they can connect to a distribution network. Smaller generators <50kW 3-phase or <17kW single phase – and which meet certain basic physical requirements - can in practice connect as per G83/1-1 – but must nevertheless inform the DNO ***prior to connection***.

[159] G81 – 'Framework for design and planning, materials specification, installation and records low voltage housing development installations and associated new HV/LV distribution substations'.

Annex 1 – DUOS Charges

Discussion about pros & cons of proposal in CDCM methodologies group for ToU DUOS charges at low voltage.

Unit charges : These charges form the lion's share of distribution network income – especially at low voltage. The CDCM calculation of distribution network charges entails a complex flow model of the physical network – in terms of predicted load – and associated use of assets. The model *factors in location* as a part of the calculation of the unit rate charge (p/kWh). This differs for each network voltage – plus also for each different category of customer / generator. In essence, other than being differentiated by different network voltage or customer type, the unit charge in DUOS offers no *explicit* signal to suppliers regarding *location – except that* for larger half-hourly customers and generators - where their DUOS tariffs are *also* differentiated by ToU (see below).

Fixed charges : vary by network voltage level. These include a locational aspect for cost recovery of the assets involved in *transport of electricity exported (generators) imported (load) from the distribution networks*.

ToU Element in DUOS Charges for half-hourly metered generators and for 100kW+ half-hourly metered customers - *is not location specific* – but instead relates to the voltage of connection – EHV & HV. *The signal is likely to be visible* - to the generator in their DUOS credits via suppliers - and to half-hourly metered & settled end-customers (as a 'pass-through' in DUOS in their supplier charges).

From a network point of view – these ToU charges offer a signal of the value at evening peak associated with (1) *higher generator output* and (2) *reduced peak demand*. The effect is to encourage better *general* 'matching' of supply and demand at peak – and so perhaps help alleviate network constraints and reduce losses.

As a *universal* charge to every generator and customer connected at EHV (and half-hourly metered customers at HV) the ToU element is perhaps a relatively 'blunt instrument' . The ToU element does not seem to offer an *explicit* signal either to a generator – or to an end-customer about how constrained the network might - or might not be *at a particular location* – but generally helps to create more 'headroom' at EHV or HV (arguably the initial connection charge / agreement already does this).

Generator ToU DUOS Charges – The generator 'super-critical' ToU element of the DUOS charge is designed to encourage *despatchable* DG to maximise output at evening peak – in effect to actively encourage an 'offset' to peak load. Applies only to generators connected at EHV. While it is not location specific, it presumably does nevertheless help to alleviate network constraints and reduce losses where these

generators are located. However, the ToU charge gives no signal to *intermittent* EHV-connected exporting generators (wind) *on the benefit which attaches to maximising output at evening peak* – in recognition that many cannot do so (Ofgem decision 2012)[160].

Customer ToU DUOS Charges at EHV (& HV) – Half-hourly settled customers may anyway be on some form of time-related retail tariff via their supplier (e.g. seasonal time of day retail tariffs). Network ToU charges therefore *in principle* align with many I&C customers' existing retail tariffs.

However, depending on their business operations, some I&C customers may have little peak flexibility. Such customers may find that the blanket / universal application of DUOS ToU tariffs is ill-suited to their main business operations. This may be particularly the case, if :

- The network was *not* particularly constrained at their location –
- or should they want an arrangement to use and / or store local wind output, including at peak periods (when it might also be low-priced provided the wind was blowing).

Customer ToU DUOS Charges – Possible Steps to Introduce at Low Voltage

A sub-group of the industry's Common Distribution Charging Methodology Group has started to explore whether the p/kWh unit rate DUOS charge should be re-vamped at low voltage into a basic peak-related ToU DUOS p/kWh charge. The idea is for this charge to remain *within* LV DUOS charges to suppliers. (Initial thinking appears to be to introduce this *ahead of* half-hourly metering and half-hourly settlement under existing arrangements). The aim would be to send a signal to *suppliers* about the costs of network operation and management associated with peak provision (constraints, losses). The hope being that suppliers will then be incentivised to better align payment of their ToU DUOS charges – by introducing more ToU end-customer retail tariffs to their customers as they roll-out smart meters. **In particular, a ToU DUOS charge does not seem to solve the problem of network (peak kW) and supplier longer-term interests (low-priced kWh from wind) –** with network & supplier interests potentially starting to diverge in the early 2020's.

Possible arguments which may favour introducing ToU DUOS charges at LV seem to be :

[160] In effect the ToU locational 'discount' is unavailable to local wind generators (Ofgem decision letter) - even where their output might offset local peak demand and so alleviates EHV network constraints or losses. So, benefit of wind output at peak, seems to get no recognition for the local energy benefit it might bring at peak .

- A clear internal industry signal that *peak* costs for the networks are – and will remain - high.
- Presently no 'peak-related' signal in DUOS charges for the vast majority of GB customers (so, 27 million).
- ToU DUOS charges *may encourage suppliers* to start to promote more ToU retail tariffs to their customers. If not, suppliers will face high peak-related DUOS charges (and which they will ultimately pass to end-customers).

Possible arguments against ToU DUOS charges at LV seem to be :

- Universal ToU DUOS charges at low voltage would seem to overlook *local* network conditions – i.e. whether a network had headroom or was constrained at a particular place. So, TOU DUOS could be an overly blunt instrument at this stage.
- Consumers *who do not want* peak-related ToU *retail tariffs* - because they have inflexible consumption and so ToU may cost them more - may become less appealing to suppliers.
- Impact on local matching / balancing of local *intermittent* 'must-run' generation with local load not clear (because you may wish to store at low-cost periods, which *for wind* may co-incide with peak).
- *Ahead of half-hourly settlement of individual customers* - other approaches – eg possible introduction of explicit capacity charges for low voltage customers as smart meters roll out – may be a *fairer* initial approach. If excess capacity charges also applied (see below), then these may also offer (1) a better proxy for *location* and (2) an incentive for self-balancing and / or *local* thermal storage matching.

Capacity Charges

These are payable by large demand (maximum import capacity – and an excess charge) and by large generators (maxium export capacity – and an excess charge) – and *as an addition to the connection charge – and are perhaps the closest proxy to a direct locational charge.*

Capacity Charge - Large half-hourly settled customers - pay a capacity charge which is visible to them - because their suppliers generally pass this through directly. This is not a locational charge as such, but it does however give a signal to the customer about the cost to the distribution network of facilitating that level of power-offtake / customer load. In addition, the *exceeded* import capacity charge gives a further signal *to that customer* that there is a cost to the network should they exceed their agreed maximum load. This charge is not location specific as such, but nevertheless seems to offer a *reasonable proxy for location* regarding the costs associated with a higher power-offtake for a specific customer than that originally agreed with their supplier.

Capacity Charge – Smaller Non-Half Hourly Customers

A capacity element is factored into the Fixed Charge element of DUOS charges paid by suppliers for their LV customers. However, this capacity charge is neither apparent or visible to end-customers – although in practice DUOS charges for large Load Profile 5-8 customers link to their assumed load factor.

An industry working group is understood to also presently be considering a possible DCUSA change, to introduce a capacity element in suppliers' DUOS charges for non-half-hourly custeomers.

Capacity charges – and exceeded capacity charges – in DUOS *to end-customers connected at LV* - might possibly in the long-run *be a more useful locational signal* than ToU for customers with increasing peak loads – and also to support local matching of intermittent generation output and local demand.

Sustainability First