Sustainability *First*

GB Electricity Demand – *realising the resource*

Paper 6

What Demand Side Services Does Distributed Generation Bring to the Electricity System?

By Stephen Andrews. Lower Watts Consulting.

Maria Pooley & Judith Ward. Sustainability First.

January 2013

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Sponsored by : BEAMA ; British Gas ; Cable & Wireless; Consumer Focus ; EdF Energy ; Elexon ; E-Meter (a Siemens business); E.ON UK ; National Grid ; Northern Powergrid ; Ofgem ; ScottishPower Energy Networks ; UK Power Networks.

Smart Demand Forum Participants : Sponsor Group ; Energy Intensive Users' Group ; Consumer Focus ; Which? ; National Energy Action ; Brattle Group ; Lower Watts Consulting ; DECC ; Sustainability First.

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Preface

Sustainability First

Sustainability First is a UK environmental 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 on **GB Electricity Demand** began in April 2011. It was supported in its first year under the Northern Powergrid Low Carbon Network Fund project - and thereafter for a further two years to April 2014 via a multi-sponsor group.

Sponsors include : BEAMA; British Gas; Cable & Wireless; Consumer Focus; EdF Energy; Elexon; E-Meter Strategic Consulting; E.ON UK ; National Grid; Northern Powergrid; Ofgem ; ScottishPower Energy Networks; UK Power Networks.

Work is coordinated through a **Smart Demand Forum** whose participants include a number of key consumer bodies: Energy Intensive Users Group, Consumer Focus, Which? and National Energy Action; plus DECC and the sponsor group members.

The project aims to identify the potential resource which the electricity demand side could offer into the GB electricity market through demand response and through demand reduction. The project aims to:

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

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

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 projects – emerging lessons and insights from the LCNF projects will be fed into the project.
- Proposals for Electricity Market Reform.

The work programme is being delivered through the Smart Demand Forum, through wider stakeholder events, and through a series of published papers and other materials. The project is run by Sustainability First. The Sustainability First team is Gill Owen, Judith Ward and Maria Pooley.

Additional expertise and inputs are provided by Serena Hesmondhalgh of Brattle Group who has developed a quantitative all-sector electricity end-use demand model. Stephen Andrews is supporting the project on Distributed Generation and Micro-Generation.

Key themes for the project include:

- **Customer Response and Consumer Issues –** A key focus for the project is to understand successful and cost-efficient demand-side participation from a customer and consumer perspective (household, industry, commercial and public sectors). This will include experience provided through the LCNF trials (e.g. tariffs, remote control of appliances, technologies such as micro-generation, electric vehicles etc.) and other similar initiatives in the UK and elsewhere. For households, this will include any particular issues for the fuel poor and potential distributional impacts.
- **Commercial** - Practical realisation of demand-side services - given different roles and requirements in the value chain. Issues likely to include: the nature of commercial agreements, the role of third parties (DNOs, ESCOs, aggregators), the kind of information-sharing likely to be necessary between parties etc. – drawing from practical experiences of the LCNF Trials and other experience in the UK and elsewhere.
- **Regulatory** – near and longer term regulatory factors that impact upon development of an active electricity demand-side for Great Britain – including current agreements between market actors, statutory codes, incentives in price controls, settlement, and third-party requirements. This will include experiences within the LCNF trials, and also feed into future considerations for price controls, RIIO and other thinking on innovation incentives.
- **Public Policy Issues** – likely economic value and potential contribution of the demand side to: cost-efficiency across the electricity sector; security of supply; carbon-emission reductions. Business models, approaches and incentives for integrating the demand side into the electricity market, including its interactions with Electricity Market Reform, smart meter roll-out and energy efficiency schemes such as the CRC Energy Efficiency Mechanism, Green Deal and Energy Company Obligation.

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

Papers published by the project to date are:

Paper 1 - GB Electricity Demand in 2010 - baseline data and context. Published October 2011.

Paper 2 - GB Electricity Demand 2010 and 2025 – Initial Brattle Electricity Demand-Side Model: Scope for demand reduction and flexible response
Published February 2012.

Paper 3 -What demand-side services could GB customers offer in 2010?
Industry paper - published September 2012.
Household paper - published May 2012.

Paper 4 -What demand-side services can provide value to the electricity sector?
Published June 2012.

Paper 5 -The electricity demand-side and wider policy developments
Published November 2012.

Paper 6 –What demand-side services does distributed generation bring to the electricity system?
Published January 2013

All papers are available from our website:
http://www.sustainabilityfirst.org.uk/gbelec_documents.html

Our subsequent papers in Year 2 will be:

Paper 7 – Evolution of commercial arrangements for more active customer & consumer involvement in the electricity demand-side.

Paper 8 – Electricity demand and consumer issues.

Future topics for Year 3 papers are likely to include:

- Longer-Term Demand-Side Innovation and Realisation
- Active I&C Customers
- Active Household and Micro-business Customers

Sustainability First
January 2013

Paper 6

What Demand Side Services Does Distributed Generation Bring to the Electricity System?

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Executive Summary

This paper seeks to describe where and how distributed generation fits into today's general demand-side picture - and to identify some of the main technical and commercial issues likely to shape how the demand-side role of distributed generation may evolve going forward.

In drafting this paper, it has become clear that there is no single or common view of the GB distributed generation sector today: the distributed generation which exists, operates and / or is planned - nor importantly, its location. Arguably, this somewhat patchy picture reflects the inherent nature, purpose and characteristics of distributed generation.

However, without some better base-line understanding (however broad-brush), of the contribution which distributed generation makes to the electricity system, including a more systematic understanding of the 'demand-side' contribution today and future potential of distributed generation, at both a system-wide and a local level, it will be hard to prioritise policies and / or measures for cost-efficient development and operation of the electricity system going forward.

The past decade has seen significant progress in the extent to which Distributed Generation now actively participates in providing demand-side services to the Balancing Mechanism. In particular DG actively contracts for Short Term Operating Reserve – and, due to successful aggregator activity, is progressively taking market share from larger, transmission-connected Balancing-Mechanism Units. DG is increasingly accepted as a reliable alternative to demand 'turn-down' though perceptions on DG reliability remain an issue.

DG has yet to carve out a significant demand-side role in other parts of the Balancing Market or in providing fault insurance or other 'security-related' services to DNOs at scale. It remains to be seen what any DG role might be in any demand-side activity in the new capacity market or in offsetting localised network expenditure.

This paper has therefore made a start by identifying some key issues and challenges with regard to the demand-side contribution of distributed generation. In particular, it highlights some important knowledge gaps which DECC and others may wish to consider how best to fill. We have outlined suggested next steps in Part IV of this paper.

Part I - The Demand-Side Role of Distributed Generation – An Overview

1 Introduction – demand-side relevance to project

This paper on Distributed Generation seeks to complement our earlier Paper 4[2], by providing a short and accessible overview of the demand-side role which Distributed Generation plays in today's GB electricity system. It also seeks to offer some limited insight into the developing 'demand-side' role which DG may increasingly play over the next 10-15 years.

The paper draws on desk research, a short review of available literature and on some informal discussions with a small number of market actors[3].

This paper is not intended to be a comprehensive review of the distributed generation sector in GB today. Rather, it seeks to describe where and how distributed generation fits into today's general demand-side picture - and to identify some of the main technical and commercial issues likely to shape how the demand-side role of distributed generation may evolve going forwards.

In pulling this paper together, it has become apparent that there is no single or common view of the GB distributed generation sector today: the distributed generation which exists, operates and / or is planned - nor importantly, its location. Arguably, this somewhat patchy picture reflects the inherent nature, purpose and characteristics of distributed generation.

However, without some better base-line understanding (however broad-brush), of the contribution which distributed generation makes to the electricity system, including a more systematic understanding of the 'demand-side' contribution today and future potential of distributed generation at both a system-wide and a local level, it will become increasingly hard to prioritise policies and / or measures for cost-efficient development and operation of the electricity system going forward.

This paper therefore makes a start by identifying some key issues and challenges with regard to the demand-side contribution of distributed generation. In particular, it highlights some important knowledge gaps which DECC and others may wish to consider how best to fill.

The paper is in four parts:

- **Part I: The Demand-Side Role of Distributed Generation – an Overview.**
- **Part II: Summary of Informal Discussions with Market Actors / Stakeholders.**
- **Part III: Carbon Implications of Distributed Generation in Providing Demand-Side Services.**
- **Part IV: Key Findings and Suggested Next Steps.**

[2] What Demand-Side Services Can Provide Value to the Electricity Sector ? Sustainability First. June 2012
[3] See Part II.

2 Definition of Distributed generation

Distributed generation (DG), is a generic term applied to electricity plant connected to the electricity distribution system.

Internationally it is also referred to as dispersed generation, decentralised generation, decentralised energy or distributed energy[4]. The definition also typically covers on-site generation (Defined in Distribution Code as 'Customer With Own Generation').

In this paper, DG is therefore any generation plant that is not connected to the transmission network. The voltage boundary for this network is 275kV in England and Wales and 132kV in Scotland. DG is not a defined legal term in either the Grid or Distribution Codes.

The Grid Code defines a Medium Power Station as having a registered capacity of greater than 50 MW but less than 100 MW; a Small Power Station, as having a registered capacity of less than 50 MW in the England and Wales transmission area; less than 30 MW in Scottish Power's transmission area; and, less than 10 MW in Scottish Hydro's transmission area. These definitions are then further distinguished to reflect whether such power stations are directly connected to one of the various transmission systems (including offshore), or, more likely, embedded in another licensed Users' system - commonly one of the 14 licensed geographically defined Distribution networks.

These distribution networks are governed by a Distribution Code, and besides mirroring the power station definitions in the Grid Code, the Distribution Code defines an embedded generator as:

'A Generator including a customer with own generation whose generation sets are directly connected to the DNO's distribution system or to another authorised distributor connected to the DNO's distribution system'.

[4] Distributed energy resource (DER) systems are small-scale power generation technologies (typically in the range of 3kW to 10MW)

3 Data available and estimates of installed plant

Long-term trends for both the generation and the use of energy are tracked and analysed on the basis of survey information requested by a Government energy department (currently DECC) under the auspices of the 'Digest of UK Energy Statistics' (DUKES) programme.

Historically, for electricity generation, this data collection has principally concentrated on large-scale (licensed) power station development (now obtained through DECC's monthly Major Power Producers (MPPs) survey), although there has been collection of separate classes of data relating to industrial on-site generation and CHP. DUKES[5] lists the 'Capacity of own generating plant', but the genset sizes are not recorded.

More recently, data relating to renewable generation projects (including DG) has been recorded in connection with the funding mechanisms administered by Ofgem (Renewable Obligation, Feed in Tariff etc.). There is also a separate database for good quality CHP. In all these circumstances generators need to register to be eligible for subsidy or support[6].

In addition there are two other maintained databases:
RESTATS, the Renewable Energy Statistics database, which contains aggregated performance statistics on all relevant renewable energy sources in the United Kingdom and,
REPD, the Renewable Energy Planning Database, which tracks the progress of projects from inception, through planning, construction and operational phases.

For large projects, these databases typically draw from an annual survey through questionnaires sent to project managers. For the larger number of smaller projects, estimates are based on information collected from a sub-sample. Both of these databases are drawn on by DUKES.

National Electricity Transmission System (NETS) Seven Year Statement 2011. National Grid lists transmission-connected generating unit data (large, medium and small power stations) and some (partially incomplete) information in its SYS on embedded plant that is provided via the DNOs on a voluntary basis.

In view of the relatively high volume of data relating to the distribution systems in England and Wales, a cut-off point of 5MW was originally adopted to reduce the data collection burden on the distribution network operators (i.e. embedded plant of less than 5MW located in England and Wales is not included).
The data for England & Wales has also been supplemented by embedded generation data

[5] http://www.decc.gov.uk/en/content/cms/statistics/energy_stats/source/electricity/electricity.aspx# Chapter 5, Table 5.9

[6] As the support mechanisms available exclusively to gas fired CHP plant are eroded, especially at the smaller scale, there is an increasing risk that CHP plant will cease to register for the CHPQA programme as the cost of such registration may start to outweigh the benefits. The result will be that the carbon benefits delivered by these plant will not be caught in Government statistics and the development of this part of the energy sector may go unseen.

directly from National Grid, (which includes some generation projects with an installed capacity of less than 5MW).

The information relating to the Scottish distribution systems provided by the Scottish network operators does not have a lower cut-off level, so many more DG projects are recorded.

For some User Systems, the information is provided on an individual power station basis while for others the information is provided on a Grid Supply Point basis, but helpfully in both cases the Fuel/Plant type is listed (National Grid SYS. Table F3 Appendix F).

As part of an earlier initiative concerning distributed generation in 2006, the Electricity Networks Association was required to collate quarterly data from the DNOs on generation projects connected to their distribution system.

At the time there was concern that renewable and CHP energy targets for the year 2010 may struggle to be met, due to connection delays or from congestion in the network. The level of detail reflected the need to record and anticipate the geographical, physical, and electrical basis of connection and operation of the DG plant.

There were 15 resource categories (including three types of wind, and five of CHP); 10 capacity steps (typically reflecting voltage of connection) covering 1.5kW Single phase, 16A single or 3 phase, 60kW, 150kW, 1MW, 5MW, 12 MW, 50MW, 100MW and finally 100MW connected @132kV.

In the event, DNOs did not need to process or connect clusters of DG at the high volumes anticipated. Other factors such as planning delays (in the case of on-shore wind), or uncertainty in Government support (as in the case for CHP), dampened the number of projects requiring connection. Given this, the ENA initiative to collect this comprehensive data set fell away in 2008.

So, of the existing data sources, neither DUKES nor National Grid provide a central register of all DG plant. Rather there is a reliance on other registers or partial information, both of which provide little detail, other than the nameplate capacity of the plant. In particular, data on smaller fossil fuelled plant is missing or has been estimated.

There is a further classification of generation plant that appears to be over-looked. In researching this report references have been made to the installed capacity of standby (typically diesel) generation. Estimates for GB vary widely between 1 GW to 20 GW of capacity. Some of this capacity may of course be included in some of the supplied figures, already quoted, but much of it may be in remote locations with no prospect of grid connection, or, inoperative plant or equipment which is too small or costly to be worth converting for parallel operation, in order to provide demand side services.

Interestingly, an ETSU commissioned report by EA Technology on 'Niche market applications for fuel cells' in 2000 refers to likely sales of 20,000 diesel generator units for the EU. This EU-wide estimate suggests that estimates for GB of some 20 GW of back-up

diesel generation, may be over-stated.

UK data is however collected on a commercial basis for equipment sales of small generators. The GenSet database (http://www.parkinsonassociates.com) is drawn from surveys of equipment manufacturers on quarterly sales of plant covering 12 bands of capacity, ranging from the smallest of 1 to 7.5 kVA up to the largest of in excess of 4000 kVA.

Information is historic and therefore trends can be observed and analysis carried out about which of these units are destined for the home market and which are exported. Similar studies are carried out for other international manufacturers and thus a picture could be built up about the UK net installed capacity in banding sizes or incremental sales basis. There is however no locational or use information of the plant so it is not possible to say whether the units are used for prime generation purposes, or standby. It is also a commercial database so any analysis of this sort would need to be commissioned.

A related published article (Powerline July/August 2006) however indicates that Western Europe annually installs in the region of 8GW of diesel units (20% of the global market at that time of 40 GW), and if there were a uniform pattern of sales, genset sizes in excess of 375kVA would make 60% of the total - 4.8GW. It would however push this data too far, to attempt an assessment of UK standby sets that could provide demand services, but clearly data exists and further, informed analysis maybe possible.

Conclusion: DECC and others such as the ENA may wish to consider the need for a more comprehensive DG database for distributed generation and stand-by plant.

4 Expected trends in DSR and DG development

DECC have produced small scale renewable deployment projections out to 2020, using the DECC in-house Feed-in-Tariff model. These projections are currently being reviewed by DECC and will become more generally available in early 2013.

In June 2009, National Grid published a consultation entitled 'Operating the Electricity Transmission Networks in 2020'. It focused on a 'Gone Green Scenario'. It was updated in June 2011. It anticipates a significant increase in embedded generation, consisting of approximately 7GW of CHP and 8GW from other technologies such as photovoltaic (PV), energy from waste (EfW), biomass and anaerobic digestion (AD) by 2020.

National Grid observed that this anticipated higher level of embedded generation would have a significant bearing on the level of demand "seen" from the transmission network and that National Grid will therefore require improved visibility of metered output from embedded generation sources and a good understanding of intrinsic demand levels at the Grid Supply Point (GSP) - the transmission/distribution network interface - in order to support super grid transformer outage placement and forecast total demand requirements.

It is National Grid's view that the demand side can play a material role in providing some of the system operator's required flexibility and National Grid has actively promoted and been successful in the integration of demand side services over recent years under the Short Term Operating Reserve (STOR) framework. Separately, during TRIAD periods, reduction in demand of between 0.5GW and 1GW are typically experienced. Looking forward, National Grid forecasts that a total of 2GW of demand response across the peak could be feasible by 2020.

The operational relationships between the system operator, DNOs and other participants will necessarily have to be enhanced and a possible operational framework is outlined in National Grid's paper around which such services could be delivered.

An increase in embedded generation will require a greater level of transparency to the system operator. Alternatively, DNOs may take an increasingly active role in managing system operations. In the National Grid report, consideration is given to how the operational relationships may have to develop to accommodate more embedded generation and demand side services.

As we move towards 2030, National Grid observe that there may also be an increasing value to DNO's to assist in managing thermal flows on their networks which may arise from an increase in embedded generation.

Without appropriate reinforcement of the distribution networks, NG also argue that it is not clear that the necessary infrastructure could be in place to accommodate demands at these levels and hence 'demand profiling' may be required to manage the loads on DNO infrastructure. Doing so in practice however, particularly at a domestic level, would not be

straightforward[7].

In the longer term, active switching of DG and responsive loads, for ostensibly local network issues, may put DNOs and suppliers in competition for Demand Side Response (DSR).

On potentially enabling dynamic demand, National Grid noted that consideration may be needed on fitting selected appliances with relevant equipment. For example, fridges could require equipment that could communicate the status of the appliance i.e. where it was in the cooling cycle and for how long any service could be provided.

Prior to 2020, NG expects that the principal relationship between the system operator and DNOs will be improved by:

- Sharing of metering data for embedded generation and,
- Development of current operational planning relationships that will move closer to real time.

New relationships which may need developing prior to 2020 would be between suppliers, aggregators, other third parties and DNOs. National Grid's paper argues that it will be critical for DNOs to understand the potential variance in demand from DSR in their network. Potentially, this could be co-ordinated through a centralised meter data manager.

The National Grid paper also argues that the most onerous distribution-level constraints are most likely to be transformer or overloaded domestic supply phases. This may be quite localised in areas that have high EV uptake and or heat pump penetration. Co-ordination between suppliers and the DNO will be required, as EVs and HP penetration increase.

Conclusion: With significantly higher levels of distributed generation than today and increasing demand-side development, the technical and commercial interaction between the system operator and the DNOs and other actors with regards to distributed generation, will need ongoing discussion – and somewhat clearer definition and development.

[7] Variable locational Use of System generation charges are used by DNOs to signal stresses or spare capacity in the network. This element of the charge is not split out at a domestic level, and even if it were, suppliers may not choose to pass it on to final customers. If the quality or reliability of supply is threatened, it could entail curtailing heat pumps or EV load on a local feeder, or, encouraging 'staggered' operation of such connected equipment, termed 'demand profiling'. This would require active cooperation of manufacturers, installers and customers. Presently there is no means to implement such an approach.

5 Class of contribution by distributed generation to demand side

The operation of distributed generation at appropriate times of the day or year can contribute to reducing demand. Potentially, this can benefit a range of players in the market.

For instance in National Grid's 2011 Seven Year Statement, of almost 9 GW of listed installed embedded medium and small generation, 3.5 GW was notified by the DNOs to be zonally 'Netted off' at the time of the System Peak. Network operators are required under the Grid Code to net off their own allowances for the output from embedded Medium and Small power stations when submitting their forecasts of demand to be supplied at the Grid Supply Points.

As already observed, in England and Wales, these listed generators do not include plants with capacity of less than 5MW, so maximum system peak demand recorded by National Grid may in reality have been even higher, had it not been for the operation of these other smaller plants, not captured by the data set.

Typically a contribution by a distributed generator to the 'demand side' could occur in several ways.

Automatically, through the running of on-site generation, (which is connected on the customer's side of meter). This would be seen as a reduction in the 'site' or premises demand. In this case, there is full customer benefit: by the networks, system operator and suppliers. Unit (kWh) and Distribution Use of System (DUoS) charge (where levied) are avoided in the period of generator operation.

Inadvertent. Unmetered 'spill' from a generator (with no export meter) occurs (meter could reverse, but usually a back-stop prevents this from registering). This could be a domestic installation, where the cost of fitting an export meter or contracting excess production is not thought worthwhile, or, at a larger site where the demand profile has been overestimated.

In such circumstances there may be no specific customer for the spill; or the output may be 'deemed' to have occurred and a correction (with a kWh benefit) could apply. This arrangement is presently applied to FiT customers with an installation of less than 30kW, although there is an intention to meter these units in the longer term. As there is no meter there is no customer DUoS benefit or charge, but there are assumed benefits for electricity suppliers through lower grid correction factors. Also, local demand diversity would be affected.

Intentional. Where generation export is metered (and contracted), the energy value is typically rewarded via a tariff, or via a fixed agreement or via a Power Purchase Agreement with a supplier, who will 'net-off' the generator output against their contracted demand (at a wholesale level). There may also be the opportunity for the supplier to avoid peak locational NG Transmission Network Use of System (TNUoS) demand charges (Triad) charges if the

embedded generation export occurs over the right (three) national demand winter-peak half hours.

Additionally DG output may attract DNO locational Generator Distribution Use of System charges (GDUoS). These will be site-locational at Extra High Voltage (EHV). At High Voltage (HV) there is a selection of distribution tariffs depending on whether the generator is intermittent or not. At both EHV and HV, charges could be positive or negative depending on the balance of generation and demand, and there is also a Time of Use element signalling generator export behaviour.

There is also value available to generators if they take advantage of non-firm connection agreements offered by DNOs, which allow lower upfront connection charges in exchange for a connection that maybe constrained in some circumstances (this may also rule out provision of Ancillary Services).

Site Standby- or Emergency Generation - Clearly there is the opportunity to run or convert site stand-by generation or emergency generation to operate in export mode to take advantage of some or all of these payments. Other contractual system and network benefits may also be available to the distributed generator via demand-side contracts with NGC and the DNO, and these are considered in more detail later.

In summary, distributed generation makes a contribution to the demand-side in several ways. Some of this contribution is remunerated, and some is not, depending on the way in which the distributed generator contributes to the demand-side.

6 Green generation reward mechanism

Generator reward mechanisms vary depending on the size of generation and its fuel source.

Schemes up to 5MW in size powered by renewable energy are rewarded by a fixed rate Feed in Tariff[8] (FiT). The FiT payment applies to the gross output of the generator and although it is metered, there is no time-of-use component in the reward tariff. This means that there is no differentiation between generating at periods of low or high electricity system costs: for example, at times of high demand, or low or high network stress. As has already been mentioned for schemes with a capacity of less than 30 kW, 'deemed' export (gross output less site use) may be assumed, or, a fixed rate will be applied. These sub-30kW schemes clearly also have no time-of-use measurement, although the modelling associated with the modified tariff may factor in some sort of shape (such as PV differentiated by occurring in daylight hours and scaled by UK location). Larger, metered, schemes can opt to take the offered fixed export rate, or, contract the export output.

Renewable Obligation Certificates (ROCs), are available for accredited generators with a capacity greater than 50kW (but have no upper capacity limit). As with FiTs, ROCs have no time of use component, although an associated power purchase agreement (PPA) covering the energy exported, is likely to have this feature - particularly for larger capacity projects. A PPA for embedded generation projects will typically capture the local value of the generation and also reference matters such as Triad avoidance, where the supplier-avoided TNUoS costs can be shared with the generator. There may be other elements in the PPA which deal with such matters as balancing risk, particularly for much larger projects, where the supplier may seek to share or off-set the risk.

The general lack of a Time of Use signal in the green reward mechanism does not stimulate the most efficient use of distributed generation, as a distributed generator can run at any time and benefit from the uniform incentive[9]. **In due course, the basic economic inefficiency of the present flat-rate structure of the FIT will require some attention. Recognition of the time-varying contribution which distributed generation can make in reducing electricity system costs, will be key.**

Metering time-varying export payments to micro-generators - A further technical question arose in the workshop discussions dealing with this paper. This concerned how, in the long-run, export payments to micro-generators could in due course be metered on a time-varying basis.

[8] At present schemes with a capacity between 50kW and 5MW can alternately opt to be registered and rewarded under the renewable obligation certificate (ROCs) scheme.

[9] Similarly, the Renewable Heat Incentive (RHI) payable, for example, for a heat pump does not encourage the use of heat either outside of peak times or at low-cost times of day, nor incentivise the development of storage, as there is no ToU element to the RHI.

EMR - Under the plans for reform of the electricity market (EMR), part of the Energy Bill 2012, the arrangements for rewarding green generation will change. The feed in tariff arrangements will be maintained for projects up to 5 MW of capacity, but the Renewable Obligation will be replaced by banded Contracts for Difference (CfDs). These are designed to give the generator a predictable, fixed-price revenue stream over the lifetime of the asset, no matter how the wholesale price behaves. The generator is compensated if the wholesale price is below the CfD strike price, or has to pay back the excess if the wholesale price rises beyond the strike price. Much detail remains to be developed as to how this mechanism will work, and how it particularly applies to distributed generation which by its nature does not trade in the wholesale market.

7 Distributed generation types and natural correlation with demand

Output of smaller scale generation schemes may not be metered, but there may be some pattern of ambient generation which can be identified as potentially correlating with domestic energy demand.

For example, solar PV has a clear diurnal profile and in the UK will have a better output in the south. In this country, PV's peak output is likely between, say mid-day and 16.00h and therefore coincides with generally lower national household afternoon demand (although increasingly, there may be a correlation with summer air conditioning load). Domestic owners of PV may also change their 'white' appliance use to limit or avoid export, as export is rewarded at a much lower level than avoided electricity consumption. Thus there may be some element of domestic demand shifting associated with this behaviour.

In the UK, on-shore wind typically generates more power outside the summer months when historically low-pressure weather systems are more common, and as such there may be some national correlation with peak electricity heating or lighting load[10].

As far as combined heat and power (CHP) is concerned at a domestic level, there will clearly be a strong correlation between domestic heating and hot-water load but as this may well be controlled by a time-clock, any premises demand reduction - or export - is likely to occur ahead of the morning electricity demand peak[11].

[10] In small, island or isolated networks, excess electricity from wind generation can be utilised, either to produce hot water, which can then be stored for later use directly or for supplemental heating, or to charge batteries. Both methods clearly shift or limit energy demand and in certain circumstances allow the local independent network to be utilised more efficiently.

[11] It is worth mentioning that in recent trials, micro-CHP was reported to possibly exacerbate early morning electricity demand pick-up by depressing electric demand prior to the morning peak (micro-CHP units were starting operation around 5a.m., reducing electricity demand prior to the morning peak and hence increasing the severity of demand pick-up later).

8 DG that can be despatched

Some renewable generation may be controllable and potentially could be despatched at times where demand and / or system costs are high or where network conditions are such that it would be useful to generate.

Hydro plant associated with a reservoir or some form of storage potentially fits into this category as does generation that relies on input fuel. This latter category encompasses a physical renewable energy resource such as waste, biomass and energy crops, where the only limitation may be the size of the storage facility and any degradation of the fuel.

Renewable gas-fuelled generation, could also be despatched where the source of gas might be from a landfill site, sewage facility or a biogas plant. Typically these facilities will have more limited storage options. For instance a landfill gas site may be able to retain a few hours' worth of gas before flaring is required or gas leaching becomes an issue; sewage gas and biogas would require dedicated gas storage facilities as the biological process associated with gas production is sensitive to the under-recovery of the gas.

Some generation technologies will also be dependent for their operation on other factors. Typically any form of CHP or cogeneration will have heat as a lead requirement. As such they will be dependent on heat storage in order to be flexible to deliver electricity demand services.

All other fossil generation is clearly despatchable, and has been used by both distribution and grid operators for many years for system or network purposes. Typically such plant will range from diesel generators through to Open Cycle Gas Turbines (OCGTs). Smaller generators may have their output aggregated or contracted for short-term or long-term running depending on the services commercially required.

Although not obviously able to be despatched or controlled, clearly all plant (including renewable ambient plant) which is held back[12] from its maximum available output, is available for further generation and may therefore contribute to ancillary 'despatchable' services. As already noted this could be associated with drawing on some additional form of storage, but the main problem for the distributed generator (unless the networks cannot accommodate full output) will be the foregone income from either the feed in tariff or renewable obligation certificate, or in the case of CHP the Renewable Heat Incentive (RHI) or heat under contract. These higher payments for running mean that such plant will have to set any commercial contract for being part-loaded at a compensating level in order not to be disadvantaged. This may well rule them out in comparison with other sources of demand services that may be on offer.

Finally, there is one further class of fossil-fuelled generator that might be brought into demand service if the commercial conditions are favourable, and is therefore worthy of

[12] Depending on the generator design and configuration, reactive power provision (MVAr) may be available without affecting the generator power output (MW)

consideration. As already noted, reliable estimates of the number and type of installed emergency or standby generation in the UK are hard to come by, although hospitals, police headquarters, MoD sites, data centres, banks, large commercial offices and utility companies (including water companies) are likely to have these facilities.

In a recent study commissioned for RWE npower[13] by LSE, it was estimated that were some 17 GW of installed standby generation in the UK. Other commentators and companies such as National Grid indicate that the commercially available resource might be less, and the only available DUKES information relates to the 'Capacity of own generation', which suggests that there is 3GW operating in the commercial sector, but it is unclear whether this covers standby generation. The condition and suitability of such plant to operate (or be converted to operate) in parallel with the electricity system in order to provide demand services is a separate unknown. Either way this appears to be a significant underused capacity that could perhaps be utilised to provide more demand or ancillary services in the future electricity system.

It has been estimated that it costs around £3k to convert and instrument a diesel standby generation set for parallel operation.[14] Wessex Water have some 30 generating sets which are situated around their region and are necessary to power water and sewage treatment plants in the event of supply failure. These have been converted to run in parallel with the electricity system and are the subject of an aggregated 30 MW contract with National Grid to provide reserve services. The generators can be instructed to start and reach full output after 15 min and are contracted to run for around an hour, until much larger, transmission-connected, generating sets can take over. Apart from providing a significant separate income for the company, it is argued that their operation and weekly testing creates an important improvement in reliability such that when they are required to operate in a real emergency they are likely to be able to do so. Other standby sets, which are tested only occasionally and for short periods, often fail when required to operate 'in anger' and lifetime of the engine is seriously affected by short-term running off-load. In addition batteries are properly charged by the regular genset operation.

Conclusion : **DECC may wish to consider a comprehensive study to establish the amount and location of installed standby generation and its suitability to offer demand side services.**

[13] 'Demanding times for Energy in the UK' RWE npower LSE Nov 2011
[14] David Andrews, Wessex Water presentation Open University Conference on Intermittency, 24th Jan 2006

9 Key commercial considerations

Generators receive income from various sources, as discussed in sections 5 and 6.

On-site generation benefits from electricity not having to be purchased from licensed suppliers and exported generation is typically sold and contracted via a long-term contract such as a Power Purchase Agreement.

Electricity from renewable generation additionally benefits from either feed-in tariffs or renewable obligation certificates. For feed-in tariffs these are likely to apply to the *gross* output of the generation rather than the actual export seen by the electricity system. The metering arrangements will reflect this. Suppliers purchasing electricity from both renewable and (qualifying) CHP generation will also currently benefit from exemption to the Climate Change Levy, and a significant percentage of that additional benefit is usually credited to the generator under a negotiated contract arrangement.

Irrespective of the generation fuel source, contracted electricity produced by DG for export will also potentially attract locational advantages, such as avoided supplier transmission network uses system charges[15] (TNUoS or Triad) and will also have their output scaled by a loss adjustment factor.

A commercial decision by a distributed generator to provide demand-side services, will take full account of these other contracts and income sources. If there is a call anywhere in the electricity system to reduce demand, then commercially, increasing output from DG achieves the same effect (assuming the local and national system can accommodate the output of the generator at the time). Similarly if there is a need to increase demand (say in order to allow the continued operation of nuclear plant or to absorb excess offshore wind generation) then the DG could commercially be instructed to turn down or cease generation.

In the first case, unless there is some existing constraint already holding back the generator, it would be fair to assume that ambient renewable plant (without energy storage) is operating in a way to maximise both the export generation payment and any additional income from subsidy schemes. In the second case, as the generation is already operating it would need to be compensated for a loss of income, and that would probably mean that it would be commercially unattractive compared with alternative demand-side options available to a network operator or supplier.

Fossil-fuelled distributed generators will not face the same loss of income, as their income principally derives from their generation activity rather than via a subsidy scheme. They will still clearly need reward for fuelling and operating the station and of course its construction if it is new build[16], and their commercial considerations will focus on these factors.

[15] It should be noted that embedded generation charging is under review by NG, and as such this benefit is under threat: http://www.nationalgrid.com/uk/Electricity/Charges/TCMF/2012+Meetings 26th September 2012

[16] Significant numbers of generators have been built for other purposes or are nearing the end of their economic life and both classification of plant may not need as such need a contribution to their original capital build cost.

There are carbon impacts arising from this: if in a situation where DG were to be commercially instructed to turn down, financial drivers meant renewable DG turned down preferentially before fossil-fuelled DG, overall emissions from the electricity system could potentially rise (particularly bearing in mind that <20MW thermal input generators, fossil-fuelled or otherwise, are excluded from the EU ETS – see Part III for further detail on this).

Figure 1 below shows the different demand-side services which distributed generators may be able to offer, depending on the key characteristics of their plant.

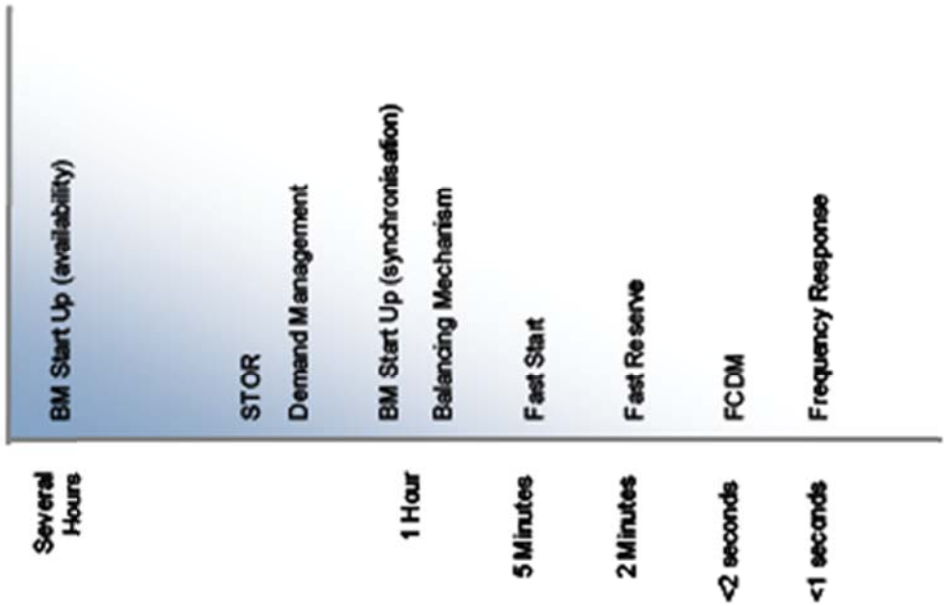


Figure 1. Demand side services which distributed generators may be able to offer, depending on the key characteristics of their plant.

10 Ancillary and DNO services - match to DG

In a comprehensive report for the former DTI, **Ancillary Service Provision from Distributed Generation** (Ilex/UMIST 2004), a value-based assessment was made to determine the attractiveness of each defined ancillary service for distributed generation. The report found that the value of the most feasible ancillary services was relatively low and would represent incremental revenue opportunities for DG. Investing in DG on the basis of ancillary service income only, was therefore considered unlikely[17].

It was found that only TSO frequency response, TSO regulating and standing reserve and DNO security of supply contributions represented realistic opportunities for DG in the short to medium term. The extent of opportunities for DNO security services would largely relate to load growth and asset replacement profiles.

TSO reactive power, DNO quality of supply and DNO voltage and power flow management services were deemed to have little potential over the same period (i.e. short-to-medium term).

Of the technologies and fuel types considered, CCGT and Doubly Fed Induction Generator (DFIG) wind farms were found to be the most promising technologies for the provision of TSO frequency services, whereas CCGTs, diesel standby generators and (perhaps micro CHP) were best placed to provide reserve services. DNO security of supply services could be provided to a varying degree by most existing DG types.

The report concluded with the following observations:

- The majority of existing DG had not been installed with the necessary infrastructure to provide ancillary services.

- To extend aggregation opportunities for DG to participate in the standing reserve market (limited by cost of infrastructure), new low-cost communication and monitoring arrangements should be evaluated.

- The most appropriate commercial arrangements for response and reserve services appear to be market-based mechanisms, potentially extending some of the TSO's current arrangements. For DNO security of supply services, the most appropriate arrangement appeared to be bilateral contracts.

- With increased levels of DG, the opportunities for ancillary services were expected to increase. However, as with the development of more active networks, network constraints and delivery uncertainty of some ancillary services might also increase. This is a major concern for DNOs as they are exposed to the risk of non-delivery. The

[17] For an overview of National Grid demand-side services and terminology in 2012, see Annex A.

impact could be financial, regulatory or legal in nature and requires further exploration.

- The majority of network security is secured through capital expenditure at present rather than operating expenditure. This relates to the current [as at 2004] regulatory framework and thus further work is necessary to establish a funding mechanism for network security and support[18].

The tables below illustrate the variety of demand side services available and the 'fit' between distributed generation technologies and demand side services.

Table 1 summarises the main ancillary services procured by National Grid (in 2004).

Tables 2 and **3** show the potential of different distributed technologies to provide different demand side response services.

Tables 2 & 3 are our current best estimate in considering what types of demand-side services distributed generation can and/or could provide.

[18] In practice, DPCR 5 (2010 – 15) changed the investment incentive on DNOs, to neutralise DNO decisions between new network investment and non-network alternatives when managing of physical constraints or other thermal or technical limitations on their networks. This incentive will carry forward into ED1.

Ancillary services	Product types	Service providers	Loading & control	Contract types	Payment arrangements
Frequency response	**Mandatory** -Primary -Secondary -High **Commercial**	-Large generators -Demand side -BM & non-BM	-Part-loaded generators -Dynamic controlled -Automatic initiation	**Mandatory** -Firm **Commercial** -Firm & -Optional	-Holding payments (£/MWh) -Response energy payments (£/MWh)
Reserve	**-Regulating** **-Standing** **-Fast** **-Warming & hot standby**	-BM -Non-BM -Large & small generators -Demand side	**Regulating** -Part loaded **Others** -Off-load -Single point of contact	**Standing Res:** **BM** -Committed **Non-BM** -Committed -Flexible	**Regulating:** -BOAs -Others -Availability (£/MWh) -Utilisation (£/MWh)
Reactive power	**Default** **Commercial** -Obligatory -Enhanced	**Generators** -BM or -Non-BM **NGCSVCs**	Generators, both partly loaded & fully loaded	**Default** -Grid code -Firm **Commercial** -Bilateral -Firm	**Default** -Utilisation (£/MVAr/h) **Commercial** -Utilisation -Availability (£/MVAr/h)
Fast Start	Fast Start	OCGT	Off load remote	Bilateral	Availability: £/h
Black Start	Black Start	OCGT	Off load	Bilateral	Availability

Table 1 Summary of main ancillary services procured by NGC in England & Wales. Source: 'Ancillary service provision from distributed generation', 2004. Report for DTI by ILEX and UMIST.

Tables 2 & 3 below are our current best estimate in considering what types of demand-side services distributed generation can and/or could provide.

		National Grid					DNO		Supplier	
		Balancing services			Ancillary services					
DG Technology type		Frequency response	Fast Reserve	STOR	Black Start	Reactive power	DNO: EHV/HV**	DNO: LV**	TRIAD service	Wholesale market impact?
Wind Non-DFIG	**<50 MW**	HF only	Possible	X	X	X	✔	?	✔	✔
Wind DFIG*	**>50 MW**	✔	Possible	X	X	✔	✔	?	✔	✔
Biomass	**1-100 MW**	HF only	Possible	Possible	Future islanding?	✔	✔	?	✔	✔
Landfill Gas	**<100 MW**	HF only	Possible	Possible	Future islanding?	✔	✔	?	✔	✔
Solar PV	**<100 MW**	X	Possible	X	X	✔	Limited	?	Limited	✔
Hydro	**>1 MW**	✔	Possible	Possible	Future islanding	✔	✔	?	✔	✔

Table 2 Strawman assessment of possible demand side services which renewable technology could provide (technical potential).

Source: Adapted from 'Ancillary service provision from distributed generation' 2004 report as above. Adapted by Sustainability First.

* Wind farms <50MW may employ DFIG machines in future (DFIG: Doubly Fed Induction Generator).
** **DNO: EHV/HV**: Fault insurance at EHV / HV level. Where a local transformer is approaching capacity, contracting with DG allows a DNO to defer network reinforcement work. **DNO: LV**: Peak avoidance at the LV network – contracting of DG to counterbalance local clusters of PV, HP or EVs.

		National Grid					DNO		Supplier	
		Balancing services			Ancillary services					
DG Technology type		Frequency response	Fast Reserve	STOR	Black Start	Reactive power	DNO: EHV/HV**	DNO: LV**	TRIAD service	Wholesale market impact?
CCGT* **	**<100 MW**	✔ ✔	✔ ✔	✔	Possible	✔ ✔	✔	X	✔ ✔	✔
Large CHP	**1-100 MW**	Limited	Possible	Possible	Future island opportunity?	✔	✔	?	✔	✔
Micro CHP	**1-5 kW**	X	Possible: High penetrations	X	X	X	Possible: High penetrations	?	✔	✔
Diesel & OCGT (standby)	**<50 MW**	Limited	✔ ✔	✔ ✔	Future island opportunity?	✔	✔	?	✔ ✔	✔

Table 3 Strawman assessment of possible demand side services which non-renewable technology could provide (technical potential).

Source: Adapted from 'Ancillary service provision from distributed generation' 2004 report as above. Adapted by Sustainability First.

* Wind farms <50MW may employ DFIG machines in future (DFIG: Doubly Fed Induction Generator).
** **DNO: EHV/HV**: Fault insurance at EHV / HV level. Where a local transformer is approaching capacity, contracting with DG allows a DNO to defer network reinforcement work. **DNO: LV**: Peak avoidance at the LV network – contracting of DG to counterbalance local clusters of PV, HP or EVs.
***CCGT >100MW will be treated as a balancing unit (including transmission charging treatment), regardless of whether it is transmission or distribution connected. In this, modified table, we have therefore focused on the CCGT with a capacity of less than 100MW.

Building on the 2004 paper, a year long DTI study was subsequently published in 2006, by a consortium of IPA Consulting, Econnect & Martin Energy. It was entitled **Reducing the Costs of System Intermittency using Demand Side Control Measures**. They examined a core concept of **Demand Side Flexibility (DSF)**. The project aimed to quantify and characterise the current and future available requirements for flexible capacity in load management, controllable generation and energy storage.

A number of site visits and interviews were undertaken to understand the process and consumption data for typical industrial and commercial energy consumers. Focusing on the water and retail industries both the demand and generation sides were analysed and characterised to provide Demand Side Flexibility in terms of their capacity, volume risks, constraints, firmness and response and 'sustain' timescales. As far as DG is concerned, they identified that independent hydro, standby diesel and flexible CHP generation could offer new Demand Side Flexibility capacity. They considered that the national capacity for diesel generation could be considerable, with estimates of up to 16GW being noted. The report further outlined principles for the use of embedded generation for DSF, and gives a detailed and useful indicative balancing capability of both demand and generation solutions overlaid with the specific class of ancillary service that is required by the transmission network operator.

The second stage of that project focused on modelling the distribution network impacts, benefits and constraints of increasing levels of DSF. The study found that for both the urban and rural networks, flexibility in existing generation was unlikely to present network problems unless associated with flexible load on the same network feeder, and vice versa. Voltage rise problems were noted as unlikely to occur on strong urban networks and generally unlikely to occur on most rural networks, unless they already had generation and flexible load already operating close to their limits, causing the voltage to exceed limits.

The third section of the study investigated the potential value of DSF in contributing to the future national balancing of electricity generation and demand. It concluded that DSF was most likely to be used to provide reserve services, whether through standing reserve or a service with a longer notice period such as contingency reserve capacity service. The report observes that a major benefit of DSF (demand or fast acting diesel generation) is that there are no variable costs or emissions associated in holding flexible plant that may or may not be used in real time. The report identifies annual system balancing cost-savings of £10k-£40k/MW, emissions savings of 300-750tCO_2/MW as well as alluding to capacity cost savings of around £60k/MW.

Finally the study identifies a range of policy measures and suggests a route map to be followed to further develop Demand Side Flexibility capacity in the future. It is unclear whether or how far these recommendations have been acted on to date. It would be worthwhile for DECC to revisit the detailed recommendations of this 2006 paper.

In a more recent report commissioned by National Grid and Electricity North West (ENW), **Assessment of DSR Price Signals** (Pöyry, Dec 2011), the relationship between different stakeholders and their use of DSR was examined.

The report noted that parties potentially require different aspects of a delivered DSR service, suppliers being interested in energy (MWh), whereas DNOs and the TSO are interested in capacity (MW).

The report outlines how these differences present varied value propositions and natures of use to DSR providers. However, the pattern that emerges from the analysis is that the price signals given by the DNO for DSR services will be far weaker than those given by other interested parties. The report suggests that a DNO probably will be unable to give the signals that it needs to attract DSR providers except in post-fault situations where spot value of DSR to the DNO would be very high. By contrast, the TSO and suppliers should be able to give the desired price signals far more readily given the scale of potential benefits via, for example, asset investment avoidance and operational cost reductions. It should be noted that these values were modelled and in 'real life' may not accurately reflect the values in specific areas with local constraints.

This ordering was also reflected in the modelled benefits received by individual parties. Firstly, the supplier often is most likely to have the most value as it gains on a frequent basis from wholesale price savings and from passing on the cost of incorporating wind generation onto its customers. The TSO follows as its investments are relatively large and infrequent; it is under certain operational obligations which drive sometimes high values for DSR. The DNO is lowest in the value chain, given the location-specific and typically lower-scale of its requirements for DSR; and thus associated asset costs and operational savings.

A useful report, was commissioned, published and debated by RWE npower in 2011. It was authored by LSE and entitled '**Demanding Times for Energy in the UK**'. It developed four 2020 energy scenarios (spanning high and low costs today and high and low environmental costs tomorrow) and analysed their consequences. Although the four scenarios lead to very different energy outcomes, there is common message to users in all of them: Pay attention to energy use and manage it wisely.

The report pays particular attention to the way in which firms can realise value from fluctuating prices, through the market for short-term operating reserve, known as STOR. The requirement for STOR is projected to grow rapidly, potentially reaching a value of £565-£945 million a year by 2020.

The report quotes from National Grid's 2009 Consultation 'Operating the Electricity Transmission System in 2020', where in the 'Gone Green Scenario' it expects STOR to be made up from around one third capacity from large generators (through the balancing mechanism), one third from outside the balancing mechanism, one sixth from pumped storage, and one sixth from demand-side management. Between now and 2025, the amount of reserve needed is expected to more than double from 3.5 GW to around 8 GW and as such it is argued that new sources of capacity will have to be found, and standby generation is expected to contribute significantly to this (RWE's own estimate of *under-utilised* self generation is 3GW today, 5GW in 2025). RWE npower has estimated that the total STOR

payments (for being available and for generating) could reach £945 million per annum by 2020, up from £205 million in 2010.

Since first publication of some of the earlier reports discussed above, there has been significant progress in the extent to which Distributed Generation now actively participates in the Balancing Mechanism. In particular DG actively contracts for Short Term Operating Reserve – and, due to aggregator activity, is progressively taking market share from larger, transmission-connected Balancing-Mechanism Units. However, as our Paper 4[19] demonstrates, DG has yet to play a significant demand-side role in other parts of the Balancing Market or in providing fault insurance or other 'security-related' services to DNOs, although there are on-going trials to explore this, under DNO innovation and Low Carbon Network Fund programmes.

The treatment of demand-side activity under EMR, will also be a matter under discussion during the passage of the 2012 Energy Bill. Better understanding is needed of where the role of DG might sit in the proposed EMR reforms against other possible DG service 'calls'.

[19] Sustainability First – Paper 4 'What Demand-Side Services Can Provide Value to the Electricity Sector?'. 2012. See http://www.sustainabilityfirst.org.uk/gbelec_documents.html

11 Technical standards

As already noted, depending on its size and at what voltage a generator is connected to the UK electricity system, it will be subject to different commercial and technical rules.

Generators connected to the distribution system have to comply with the technical requirements of the Distribution Code. This in turn references Engineering Recommendations (ER) outlining the technical terms for connection, operation and disconnection of generation - the aim of the ER is to protect both the DNO and DG equipment. Microgeneration schemes, typically less than 5 kW, have simpler and less costly protection arrangements than generators (up to 5 MW) but still nevertheless connected to the low voltage electricity system. Microgenerators will not normally need to prove their safe operation or seek prior consent to be connected as they would have gone through some form of 'type testing'. Larger schemes may be differentiated by their generator type and whether they can operate independently of the grid or in emergency situations. They may also require witnessing tests to prove that the protection is set up as intended.

Much larger DG projects will face more stringent technical operation, and increasingly will be seen to have similar requirements to larger-scale transmission-connected generation, who will be required to operate under the Grid Code.

Historically distribution networks have connected generation on a 'fit and forget basis'. This means that they have designed the connection to the generator to allow it to operate in all circumstances, but rely on the deemed protection to disconnect the generator if the system conditions dictate. (Unlike transmission connected generators, DNOs are not required to compensate DG in the event they are disconnected).

Conversely transmission network operators require their connected generation to continue to operate in much more adverse conditions, (but also permit them to offer commercial support services). Not to do so, may make a bad situation much worse, ultimately requiring the grid to be partly or fully re-energised (a costly and technically demanding process known as a Black Start). (Moving forward to significant amounts of transmission connected intermittent wind and inflexible nuclear, this risk becomes more acute).

Transmission network operators are becoming uncertain about how best to respond to the amount of distributed generation connected, as it is not 'visible' by them - and as such the system operator may need to carry more national reserve. In particular they are concerned about the rapid disconnection of DG in a fault situation, and then subsequently with automatic reconnection while a fault is being resolved.

Various measures are being considered to address this situation, and some of them have already been noted in this paper.

National Grid has also already suggested that more data will need to be made available to them by the DNO's concerning the connection of embedded generation plant. In the last few

years changes have been made to the setting of protection relays for distributed generation as it was felt that the Distribution Code compliance level was technically over-sensitive.

Internationally, the transmission and distribution systems (and generation activities) are often not separated in the same way as they are in the UK and they may have common rules and technical requirements across both the high and low voltage networks. As Europe becomes more integrated and interconnected, legislators are turning their attention to common international standards, (including, for example with respect to frequency relays).

Requiring a 10 kW standby generator to fit and adopt the same running conditions and protection settings as a 500 MW generator connected to the transmission system clearly may present a major cost inhibition for the small plant.

Technically mandating operation of a generator - or a demand - to have frequency response, arguably, could obviate transmission or distribution system operators contracting commercially for that response. A proper understanding of both the commercial and technical impacts of proposals to mandate frequency control, or other technical parameters, is an important feature of the debate.

Conclusion: Mandating DG behaviour is not just a technical issue but also a commercial matter. It is important that the appropriate costs and benefits are well understood before proceeding.

Part II – Summary of Informal Discussions with Market Actors / Stakeholders

We carried out a small number of informal discussions with market actors and others to gain some further insight into how, from their point of view, they viewed the demand-side role of Distributed Generation. Below we summarise some common key themes.

The following informally discussed the demand-side distribution of DG with Sustainability First as background to this paper:

- National Grid
- Ofgem
- An aggregator
- Electricity North West
- UK Power Networks
- Northern Power Grid
- A renewable trade body

Responsibility for our summary of these discussions, including any initial conclusions, rest with Sustainability First and not with our interviewees. Views expressed here are those of Sustainability First.

1. What demand-side services does distributed generation provide at present?

At present Distributed Generation provides only limited demand-side services to market actors.

Some distributed generation participates in the Balancing Services contracted by National Grid (e.g. STOR (Short Term Operating Reserve)).

From a DNO perspective, DNOs presently have in place a very small number of contracts or agreements with distributed generation providers (generally industrial players with DG onsite) to provide additional capacity.

These contracts may enable DNOs to defer investment in local networks, and the DNO therefore has a choice between investing in network reinforcement, or paying for distributed generation (assuming the DG is sufficiently reliable). In this situation, the cost of contracting the distributed generation can be compared to the annuitized cost of avoided investment.

DNOs may also have conditional connection agreements with some DG (e.g. wind), which similarly allows the DNO to avoid network reinforcement. In these cases the DNO can require DG to switch off / turn down generation at a signal from the DNO.

2. What demand-side services could distributed generation provide in the future?

Market actors felt that in a future which includes both significant new local load (due to the rollout of electric vehicles and heat pumps), and more distributed generation (e.g. through PV), that distributed generation will have the opportunity to play a more significant role in peak avoidance. What is not apparent is exactly how this potential will be realised, as current infrastructure and commercial arrangements are not necessarily designed with distributed generation in mind. For example, in a high-PV future scenario, other DG could be contracted to turndown during peak PV output hours.

Do market actors have a reliability-based preference for distributed generation vs DSR?

On the whole, those market actors we spoke to did **not** have a preference for DSR over DG.

Historically there has been a perception of DG as being less reliable than DSR – one line of argument being that it is easier to stop a process or switch-off equipment (and so reduce demand) than to start-up or switch on equipment (for DG). However, former concern regarding the reliability of DG seems to have faded, possibly due to increasing experience in contracting with DG for demand-side services. On the other hand, the set-up process for engaging demand side services from DG is presently more straightforward than for engaging active DSR, as contracting for DG services does not require a fundamental change in operations.

From the point of view of the system operator, National Grid, the main concern is visibility and reliability of any demand or generation, to ensure accurate forecasting. For example, any DSR occurring without prior notification/knowledge of National Grid, in effect adds to the forecasting error margin and therefore leads to more error margin being allowed for in subsequent days (and consequently more reserve being held and therefore higher Balancing costs).

Would market actors distinguish by fuel or technology type?

The market actors we spoke to felt that wind and PV should be considered commercially as a 'non-despatchable' generation source, and therefore not considered for the purposes of reliable DG demand-side services. (DNOs said they would not contract for wind or PV as DSR).

However beyond these commercially-driven reliability considerations market actors do not and would not discriminate by fuel type when contracting the services of DG as DSR.

The issue of storage was raised several times – if electricity storage were to become more affordable than it is today, then DG from wind or PV would become commercially more useful than it is at present, and its ability to provide demand-side services greater (DG

combined with storage). Currently the best commercial option for intermittent DG (so wind, PV) seem to be likely to be associated with thermal storage, e.g. hot-water storage, rather than electricity storage.

Is there a de minimis limit to interest in DG?

Very few actual de minimis limits have been identified. At present within the Low Carbon London trials, the minimum level which will be considered is 300kW – but this is 300kW aggregated, so can potentially be provided by a number of smaller units.

As described in more detail in the Barriers section below, the main issue with engaging with smaller units of DG is the resource required to manage a large number of transactions.

Local and community level demand-side role for DG - and current incentives

It seems likely that DG will continue to play a demand-side role, particularly at a very local level within DNOs, where network constraints exist.

However, currently if a DNO identifies a particular *location* likely to benefit from firm DG, (for example, as a possible offset to very local 'peak-load' clusters in the LV networks from EV or perhaps HP) other than the annuitized cost of avoided investment in equipment and cable, it presently has only limited tools at its disposal to invite or to encourage a developer of distributed generation to set up in a particular location. Depending on the voltage of connection, this would be via negative (generator) use of system charges. Non-firm connection agreements for distributed generators could also play an increasing role.

Conclusion: current incentives available to DNOs to encourage DG at a local and/or community level (however 'local' is defined), to offset network expenditure due to 'clustering' of heat pumps and/or EVs, need to be further considered as a part of the DNO demand-side toolkit going forward. It is as yet unclear whether new non-firm connection agreements for DG, together with negative GDUoS charges for DG will in the end offer a sufficiently strong signal to incentivise the right kind of DG to develop at a particular location.

3. What barriers are there currently to further participation of DG in DSR?

Resource barriers

For a DNO to engage with many small distributed generators, or with individual households, would increase the number of transactions undertaken by a DNO in a year significantly, and consequently increase the costs to DNOs of managing these transactions. At present DNOs have not the resource to manage such numbers of transactions themselves, and are not set up to cater for them although there could be a role for aggregators.

Technical & regulatory barriers

At present DG and DSR are not a very significant part of a DNOs' 'toolkit' when managing their assets. This is partly due to the technical codes regulating DNO operations – e.g. at present under P2/6, DSR cannot be included in calculations of network robustness / need for reinforcement. However, Ofgem has asked DNOs to review these regulations, to allow a more flexible approach to DG[20].

Hand-in-hand with the regulation and codes there are long-standing practices which will require a culture change to take place before DG and DSR are habitually considered / used in the management of distribution networks.

4. If we expect DG to provide more demand-side services in the future, do we expect this to occur through regulation (technical standards) or by commercial mechanisms?

Opinions on this subject varied. There is support from some quarters for the use of technical standards to enable more DSR participation by DG. However, overall, market actors believed **both** commercial mechanisms and technical standards should be used, so that technical standards should be used in a targeted way where:

a) commercial mechanisms would not be expected to succeed, or where
b) technical standards would lower overall costs to the customer.

For example, two of our interviewees thought that technical standards may be an effective way of ensuring the participation of frequency response services, possibly from DG or possibly from household cold appliances, in demand-side response.

5. Issues of centralised and non-centralised data collection for DG installations.

Market actors are aware that at present there is no centrally-held database recording all DG installations. It is recognised that this issue affects non-HH metered DG.
DNOs are notified of sub-HH metered DG installations through the submission of G83/59 notifications to the DNO[21] . However, this is a one-off notification at a static point in time. If the DG installation is subsequently switched off or changes ownership, DNOs have no knowledge.

[20] There is currently a consultation open on revising Engineering Recommendation P2. The consultation is being run by the Electricity Networks Association and is open until the 18th January 2013.
[21] FiT registration forms are separately submitted to Ofgem.

Initial overall conclusion from our informal discussions with market actors / stakeholders

Firm DG can play a role today in avoided network reinforcement, subject to the planned revision of technical standards in P2/6.

In the long-run, subject to P2/6 revisions, certain kinds of firm DG could play a more significant cost-saving role at very local level in the low voltage distribution networks, to offset / complement new peak-loads from EVs or heat pumps.

A DNO can currently arrange a bi-lateral contract with an existing distributed generator for limited services – perhaps for 'insurance' services in support of fault management.

However, currently if a DNO identifies a particular *location* likely to benefit from firm DG, (for example, as a possible offset to very local 'peak-load' clusters in the LV networks from EV or to HP) other than the annuitized cost of avoided investment in equipment and cable it has only limited tools at its disposal to invite or to encourage a developer of distributed generation to set up in a particular location. These include non-firm connection agreements, and, depending, on the voltage of connection, via negative (generator) distribution use of system charges. It is as yet unclear whether connection agreements, together with negative GDUoS charges for DG will in the end offer a sufficiently strong signal to incentivise the right kind of DG to develop at a particular location (rather than just in a demand stressed zone).

Part III - Carbon Implications of Distributed Generation in Providing Demand-Side Services

The issue of the carbon implications of DG in providing DSR is complex.. It is not our aim here to provide a definitive discussion, rather to highlight some key points and to foster discussion. Further work is needed by others on this topic.

This issue regularly arises in discussions regarding DG provision of demand-side services. In this section we have drawn on our conversations with market actors and stakeholders, and from a brief literature review, sought to set out some main points regarding the carbon implications of DG provision of demand-side services. We do not have the answers. Rather, our aim here has been simply to set out different facets of this issue.

The carbon balance of distributed generation which provides demand-side services

When Distributed Generation provides demand side response services to the electricity system, it may lead to a **reduction** in overall CO_2 emissions from the system by:

- Displacing peaking plant,
- Displacing larger generation sets which are running **part-loaded** for the purposes of providing regulating services (e.g. in STOR periods),
- Reducing transmission and distribution losses, by providing generation near to the demand point.

However, potentially, distributed generation may **increase** CO_2 emissions from the system through:

- Operating smaller, less efficient generation units than the BM plant they are displacing (e.g. a small diesel generator displacing output from a large CCGT gas power plant).

The **fuel** used by the distributed generator has a direct impact on the carbon balance, as the emissions per unit provided (tCO_2/ MW) from a diesel back-up generator will be higher than from e.g. a gas CHP or a biomass plant.

Given the number of variables involved in determining the carbon impact of distributed generation providing DSR – size and fuel of the DG unit, location of DG (and therefore avoided transmission losses), type of BM unit displaced (gas or coal, varying efficiencies) – it is difficult to state conclusively what the general carbon impact of distributed generation used for demand-side services may be.

Additionally there is very little published data on this topic, and certainly no comprehensive overview study. The following presents the key studies we have found which touch on this issue.

The 2006 DTI study '**Reducing the cost of system intermittency using demand side control measures'**[22] by IPA Consulting, Flexitricity and Econnect analysed the potential for the use of Demand Side Flexibility (DSF[23]) for electricity system balancing.
The report estimated that the use of Demand Side Flexibility for balancing purposes, where it displaces **spinning plant**, could result in emissions savings of between 0.08-0.17tCO_2/MW/h, equating to savings of 300-700tCO_2/MW/year of DSF capacity. The use of DSF to provide **contingency type reserve services** was estimated to result in an emissions savings of around 1.2 tCO_2/MW over warming a warm coal plant.

Distributed generation and existing policies to curb carbon emissions

Current key policies in relation to carbon reduction:

- EU ETS: generation units <20MW thermal input are excluded from EU ETS.
- The Climate Change Levy does not apply to fuel used for electricity generation.
- CHP has bespoke treatment.

From April 2013:

- Carbon Price Support. Generation units <2MW electric output will be exempt.

Therefore currently fossil-fuelled DG units under 20MW thermal input may be adding to total uncapped emissions (emissions not already capped under the UK's emissions National Allocation Plan). In terms of financial drivers, it has been highlighted that the price of diesel is a far more significant driver than the relative cost of purchasing EUAs within the EU ETS.

Conclusion: **At present the carbon implications of increasing DG participation in demand-side services are unclear. Further work on the carbon impacts of various DG forms (fossil-fuelled and non-fossil fuelled) providing demand-side services, and highlighting any potential policy impacts or gaps in this area, would help to provide some useful clarification.**

[22] 'Reducing the cost of system intermittency using demand side control measures', IPA Consulting, Econnect Ltd & Martin Energy. See: http://webarchive.nationalarchives.gov.uk/20100919181607/http:/www.ensg.gov.uk/assets/kel0003460000.pdf
[23] Demand Side Flexibility was defined to include 'flexible, responsive operation of any distribution-connected equipment, including consumers, generators and energy storage plant'

Part IV - Key Findings and Suggested Next Steps

This paper has sought to describe where and how distributed generation fits into today's general demand-side picture - and to identify some of the main technical and commercial issues likely to shape how the demand-side role of distributed generation may evolve going forward.

In drafting this paper, it has become clear that there is no single or common view of the GB distributed generation sector today: the distributed generation which exists, operates and / or is planned - nor importantly, its location.

The past decade has seen significant progress in the extent to which Distributed Generation now actively participates in providing demand-side services to the Balancing Mechanism. In particular DG actively contracts for Short Term Operating Reserve – and, due to successful aggregator activity, is progressively taking market share from larger, transmission-connected Balancing-Mechanism Units. DG is increasingly accepted as a reliable alternative to demand 'turn-down' though perceptions on DG reliability remain an issue.

DG has yet to carve out a significant demand-side role in other parts of the Balancing Market or in providing fault insurance or other 'security-related' services to DNOs at scale. It remains to be seen what any DG role might be in any demand-side activity in the new capacity market or in off-setting localised network expenditure.

This paper has therefore made a start by identifying some key issues and challenges with regard to the demand-side contribution of distributed generation. In particular, it highlights some important knowledge gaps which DECC and others may wish to consider how best to fill.

With that in mind we suggest the following next steps:

1. A more comprehensive DG database - DECC and others such as the ENA may wish to consider the need for a more comprehensive UK DG data-base for distributed generation and stand-by plant.

2. Commercial frameworks - With significantly higher levels of distributed generation than today and increasing demand-side development, the technical and commercial interaction between the system operator and the DNOs and other actors with regards to DG, will need ongoing discussion – and somewhat clearer definition and development.

3. DG within EMR - The treatment of demand-side activity under EMR, will be a matter for discussion during the passage of the 2012 Energy Bill. Better understanding is needed of where the role of DG might sit in the proposed EMR reforms against other possible DG service 'calls'[24].

[24] Annex C to the EMR documentation 'The Capacity Market Design and Implementation Update' (published November 2012) outlines transitional arrangements to allow DSR and storage to participate in the Capacity

4. Costs and benefits of mandating DG to provide demand-side services - Mandating DG behaviour is not just a technical issue but also a commercial matter. It is important that the appropriate costs and benefits are well understood before proceeding.

5. Feed-In Tariff and a Time-of-Use Signal - The general lack of a Time of Use signal in the green reward mechanism does not stimulate the most efficient use of distributed generation, as a distributed generator can run at any time and benefit from the uniform incentive[25]. In due course, the basic economic inefficiency of the present flat-rate structure of the FIT will require some attention. Recognition of the time-varying contribution which distributed generation can make in reducing electricity system costs, will be central.

6. Study of UK stand-by generation - DECC may wish to consider a comprehensive study to establish the amount and location of installed standby generation and its suitability to offer demand side services.

7. DNO demand-side toolkit - current incentives available to DNOs to encourage DG at a local level and/or community level (however local may be defined), as an offset to network expenditure due to 'clustering' of heat pumps and/or EVs, need to be further considered as a part of the DNO demand-side toolkit going forward. It is as yet unclear whether non-firm connection agreements together with negative GDUoS charges for DG will in the end offer a sufficiently strong signal to incentivise the right kind of DG to develop at a particular location.

8. Carbon implications of DG providing demand-side services - At present the carbon implications of increasing DG participation in demand-side services are unclear. Further work on the carbon impacts of various DG forms (fossil-fuelled and non-fossil fuelled) providing demand-side services, and highlighting any potential policy impacts or gaps, would help to provide some useful clarification.

Market – these include preparatory or pilot auctions prior the first 'live' secondary auction in 2017. See http://www.decc.gov.uk/assets/decc/11/policy-legislation/EMR/7104-emr-annex-c-capacity-market-design-and-implementat.pdf for further detail.

[25] Similarly, the Renewable Heat Incentive (RHI) payable, for example, for a heat pump does not encourage the use of heat either outside of peak times or at low-cost times of day, nor incentivise the development of storage, as there is no ToU element to the RHI.

Annexes

Annex A. Table of National Grid services terms

<table>
<tr><td rowspan="15">Balancing Services</td><td rowspan="13">Ancillary Services</td><td rowspan="3">System Ancillary Services</td><td rowspan="2">“Part 1 System Ancillary Services” or “Mandatory Ancillary Services”</td><td>Mandatory Frequency Response</td></tr>
<tr><td>Obligatory Reactive Power Service</td></tr>
<tr><td rowspan="3">Part 2 System Ancillary Services</td><td>Fast Start</td></tr>
<tr><td>Black Start</td></tr>
<tr><td>System to Generator Operational Intertripping</td></tr>
<tr><td colspan="2" rowspan="11">Commercial Ancillary Services</td><td>BM Start-Up</td></tr>
<tr><td>Short Term Operating Reserve (STOR)</td></tr>
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<tr><td>Maximum Generation</td></tr>
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<tr><td colspan="4">Forward Energy Trades</td></tr>
</table>

Annex B. Referenced reports

Ancillary Service Provision from Distributed Generation
DTI Contract Number: DG/CG/00030/00/00
URN Number: 04/1738
Ilex Energy Consulting/UMIST 2004

Reducing the Costs of System Intermittency using Demand Side Control Measures
DTI Contract Number: K/EL/000346/00/00
URN Number: 06/1432 IPA Consulting, Econnect & Martin Energy 2006

Assessment of DSR Price Signals
ENW and National Grid
Pöyry Dec 2011

Demanding Times for energy In the UK
LSE, report commissioned by RWE npower Nov 2011

Electricity System: Assessment of Future Challenges
DECC 9 August 2012

Operating the Electricity Transmission Networks in 2020
NGC June 2009 & 2011

NG's use of Emergency Diesel Standby Generator's in dealing with Grid Intermittency and Variability Potential Contribution in Assisting Renewables
David Andrews, Wessex Water presentation Open University
Conference on Intermittency, 24th Jan 2006

2011 NETS Seven Year Statement: Chapter 4 – Embedded and Renewable Generation

DUKES New renewables table and amendments to electricity tables Dec 2010

Quantifying the System Costs of Additional Renewables in 2020
DTI Ilex Energy, Goran Strbrc UMIST Oct 2002

Demand side response in the non-domestic sector
Ofgem Element Energy, De Montfort University Leicester July 2012

The Tradable Value of DG
Contract Number DG/DTI/00047
URN Number: 05/1228 Ilex Energy Consulting 2005

Sustainability *First*

Sustainability *First* was set up to develop new approaches to sustainability. Its primary focus is on policy and solutions within the UK, but draws on experiences and initiatives both within and outside the UK.

Sustainability *First* develops implementable ideas in a number of key policy areas – notably, energy, water and waste - where it can make a difference. It undertakes research; publishes policy and discussion papers; organises high level seminars and other events. Sustainability First is a registered charity.

Sustainability *First*'s trustees are: Ted Cantle (Chair); Phil Barton (Secretary); Trevor Pugh (Treasurer); Richard Adams; Sara Bell; John Hobson; Derek Lickorish; Derek Osborn; David Sigsworth. Its projects are developed by the trustees and a number of associates and consultants.

Sustainability *First's* Director is Judith Ward.

Sustainability *First*'s associate is: Gill Owen.
Maria Pooley is Sustainability *First*'s research officer.

Sustainability *First* is a registered charity number 107899.

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Sustainability *First*