Policy and Regulatory Barriers to Local Energy Markets in Great Britain

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Abstract: The requirement to decarbonise the GB electricity system, alongside the falling costs of renewable technologies and developments in IT capabilities, provides GB with an opportunity for systemic change in the way that electricity is produced and sold, with the potential to enable flexibility markets at the local level given the correct regulatory conditions.

The report highlights a range of regulatory and policy barriers to the Local Energy Market (LEM) approach.

Keywords: LEM, distributed energy, DSR, markets, networks, local, renewables

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EXECUTIVE SUMMARY

This report studies the current GB policy and regulatory environment regarding electricity markets and how these market rules can potentially be a barrier to the development of new local energy markets at the distribution level across GB. Barriers could be in the form of existing policies and regulations, or a lack of enabling policies and regulations. This report also discusses the changes which are currently emerging in the national and regional energy markets and how these changes could impact on the creation of local energy markets in GB, either negatively or positively. We have also contrasted these changes with international examples where appropriate.

The GB energy market is currently undertaking rapid change, which is recognised by many key stakeholders. Change can be attributed to energy sector decarbonisation targets (Shakoor *et al.*, 2017) combined with the emergence of new technologies in generation, demand and control systems (Ramos *et al.*, 2016).

Much of this change is happening at the distribution network level (Ruester *et al.*, 2014). Distribution has traditionally been seen as the 'junior' partner to transmission, (Nolan, 2015) fed from the much larger arteries of the transmission network and operated passively. However, as distributed generation grows and large scale power station capacity falls, more power will be connected at the distribution level (WPD, 2017b) which will have a major impact on the roles of the GB Transmission System Operator (TSO) and the Distribution Network Operators (DNOs), with the DNOs potentially becoming major operators in procurement of services and system balancing in future (Nolan, 2015).

The amount of generation in GB that is connected at the distribution level has doubled over the last 5 years and now represents over a quarter of total GB capacity (Ofgem, 2017k). This creates a number of issues for the DNOs regarding the impact of distributed generation on networks which were not originally designed to accommodate generation, but which were built with a 'fit and forget' approach (Ramos *et al.*, 2016). These issues include voltage deviations, line losses, system balance and reserve issues, robustness and power quality.

Conversely, the growth in distributed generation has the potential to transform the current market structure of electricity trading and introduce new services and markets. New emergent services could include dynamic pricing, aggregation, peer-to-peer trading and various demand side management options which can help to overcome system balancing issues; whilst new markets such as local energy markets can provide a route for smaller providers to deliver these services.

To enable this transition from a top-down, one-way system to a much more complex distributed network, the roles of key market actors will need to evolve (BEIS and Ofgem, 2017a). A number of activities are already being progressed by BEIS, Ofgem, National Grid, the ENA[1] and the DNOs as will be discussed in this report. However, there is much to be determined over the next few years in relation to the current monopoly roles of the TSO and the DNOs (BEIS and Ofgem, 2017a); as well as the role of suppliers, aggregators and the emergent roles that might be established by new innovative market entrants.

[1] Energy Network Association

Current policies, regulations and market rules all revolve around the Supplier Hub model (see Section 2.1). However, a different market structure will be needed for an industry that transforms from a top-down system to one that fully enables distributed generation and peer-to-peer trading with a small amount of high voltage interconnection between distributed generation and smaller more localised networks (Elexon, 2017a).

As system flexibility will be the key enabler in delivering this transformation (Shakoor *et al.*, 2017), Government needs to ensure that independent flexibility markets are made more accessible for small energy providers, by removing regulatory barriers, and ensuring value for flexibility. For this reason greater strategic direction is required from BEIS and Ofgem.

These changes in the energy market can be capitalised on by smaller generators and distributed energy resource providers, but only if the correct market conditions are established to enable their successful entry. This report will therefore discuss barriers to current markets and opportunities for future markets, where the Cornwall Local Energy Market could establish routes to market for local energy providers and prosumers.

DOCUMENT ROADMAP

This report is structured in two main parts:

PART 1 - CURRENT MARKET DESIGN – which outlines the current state of play in GB markets and how they need to be adapted to incorporate the rise of DER.

In **Section 2** we discuss how electricity systems are changing in GB due to decarbonisation targets and the development of renewable and low carbon technologies, with much of the growth in renewable generation happening at the distribution level. This is increasingly leading to a need for change in how networks are managed and balanced, which in turn could also lead to the implementation of more distributed local energy markets. However, one of the central barriers to market change is the current supplier hub model which is also discussed.

In **Section 3** we look at the existing GB markets and highlight the barriers for small distributed generators, storage and DSR providers to participate in them. We also discuss current proposals by BEIS / Ofgem to improve access by DER to these markets.

In **Section 4** we discuss how the network operators will need to re-evaluate their roles and responsibilities and develop new working practices. DER will increasingly cause disruption to the current way of balancing the transmission and distribution networks, leading to a need for a re-evaluation of the way in which the networks will function in future and the opportunities this could create for developing local energy markets.

In **Section 5** we look at current Ofgem consultations regarding network charging and how these changes could potentially cause a barrier to small generators and behind-the-meter prosumers.

PART 2 - POSSIBLE MARKET CHANGES – which outlines changes which could facilitate the rise of DER and the creation of local energy markets.

In **Section 6** we look at some of the new technologies and market approaches which could facilitate local energy markets. These include DSR, storage, the role of aggregators in enabling smaller providers to access the market as well as new market approaches such as Peer-to-Peer trading and Locational Marginal Pricing. However, there are regulatory and market barriers which need to be addressed in all cases.

1. INTRODUCTION – THE CORNWALL LOCAL ENERGY MARKET PROJECT

The Cornwall Local Energy Market (LEM) project is a three-year trial from 2017 to 2020 jointly funded through the European Regional Development Fund and Centrica. The project is led by Centrica in association with project partners Western Power Distribution, National Grid, Imperial College London and the University of Exeter (UoE).

The LEM project will create a local marketplace for flexible demand, generation and storage in Cornwall. The project will achieve this by designing and building an independent market platform where the DNO and the TSO can procure flexibility from distribution connected assets; allowing both supply and demand side providers to participate in trading and optimising capacity on the network.

This model of electricity trading and network operation differs significantly from the way in which the UK electricity system currently operates. Markets and network operation have historically been designed to reflect the 'conventional' centralised configuration of the system, rather than supporting smaller scale, more active local participation. Policies and regulations in place at the moment may therefore act as a barrier to the development of a model which allows more local trading of power and flexibility.

UoE's remit in Phase 1 (this report) is to analyse the current GB policy and regulatory environment to identify the regulatory barriers to establishing local energy markets and suggest possible solutions.

The University of Exeter will also follow the LEM trial in Phase 2 by way of the development of an evaluation framework to assess customer expectations and experiences in trading with the LEM. In light of this qualitative analysis UoE will then provide a final report in Phase 3 with recommendations for any regulatory change required in order to allow the future development of other local energy markets across GB.

CREATING THE UK'S FIRST LOCAL ENERGY MARKET

Cornwall is outperforming most local authorities in England and Wales in its renewable energy generation, currently ranking 4th out of 56 local authority areas, with a total renewable capacity of around 764 MW, of which 72% comes from solar (where the authority is ranked 2 / 56) and 17% comes from onshore wind (Green Alliance, 2016), there are also developments taking place locally in biomass, hydro, geothermal and marine technologies.

However, the DNO, WPD, claims that this abundance of renewable energy generation has put the local electricity grid under severe strain, resulting in WPD creating a waiting list, or queue, for new renewable energy projects seeking new connections in Constraint Managed Zones (CMZ). The queue is governed on the principle of last in, first out (LIFO) which determines that those last in will be curtailed first during times of system stress. This has a severe detrimental impact on the financial viability of new projects, by seriously curbing potential output.

Cornwall Council meanwhile has an ambitious vision for a local renewable energy economy. Cornwall's Energy Future document (Cornwall Council, 2017) identifies clear targets for 2030 which include:-

- Meeting 100% of Cornwall's electricity demand from renewable and low carbon sources;

- Increasing the proportion of Cornwall's energy that is owned locally to 50% and
- Increasing the proportion of Cornwall's energy 'spend' retained within the local economy to 30%.

These targets are not likely to be met in the current market paradigms and in a constrained network. The Cornwall LEM project will therefore become an important asset in unlocking the network through working in partnership with WPD to overcome system constraints. The LEM will do this through the trialling of several different innovative solutions.

The Cornwall LEM is therefore an enabler, aiming to release network capacity as a result of more intelligent management of demand, generation and storage particularly in constrained areas of the grid. It will incentivise participants to turn up, down, export or import depending on what renewable generation is doing on the grid in real time.

The LEM project will do this through designing and building a local marketplace platform for the network to request, and the market to provide, flexible demand, generation and storage to help optimise capacity on the local grid. The platform will assist in the co-ordination of with distribution networks and the transmission system.

LEM customers in the initial three-year trial period will include I&C customers, SMEs, and one hundred domestic properties.

It is anticipated that the LEM platform could help to increase the amount of renewable generation in Cornwall in the following ways: -

- Freeing up grid capacity with more intelligent management of demand, generation and storage
- Reducing the cost for existing and new connections
- Improving the business case for renewables after cuts to feed in tariffs
- Improving the ease and cost of connecting to the distribution network
- Increasing productivity of the renewables that are constrained at times of peak generation
- Increasing the capacity of existing sites

The Cornwall LEM participants will also be seeking to sell their flexibility services into a range of National Grid services; but for local markets to succeed in GB and elsewhere, regulatory and market barriers to such markets must be understood and addressed. That is the purpose of this report.

Part 1 CURRENT MARKET DESIGN

2. GB ELECTRICITY SYSTEMS ARE CHANGING

The GB energy market is undertaking rapid change, which is recognised by many key stakeholders. Change can be attributed to energy sector decarbonisation targets (Shakoor *et al.*, 2017) combined with the emergence of new technologies in generation, demand and control systems (Ramos *et al.*, 2016).

The European Union regulatory target states that at least 20% of the energy consumed in the EU in 2020 should be from renewable resources, growing to at least 27% by 2030 (European Commission, 2016a). The EU also commits itself to becoming the world leader in renewable energy, and the global hub for developing technically advanced and competitive renewable energies (European Commission, 2017).

The EUs 'Clean Energy Package' (European Commission, 2016a) presents regulatory proposals to achieve these objectives, and at the same time accelerate the EU economy's clean energy transition. With a turnover of around €144bn in 2014, the renewables industry is already a major contributor to the EU economy (European Commission, 2017).

Much of the growth in renewable generation in GB is happening at the distribution network level (Ruester *et al.*, 2014). Indeed, the amount of generation in GB that is connected at the distribution level has doubled over the last 5 years and now represents over a quarter of total GB capacity (Ofgem, 2017k). This creates a number of issues for the Distribution Network Operators (DNOs) regarding the impact of distributed generation on networks which were not originally designed to accommodate generation, but which were built with a 'fit and forget' approach (Ramos *et al.*, 2016). These issues include voltage deviations, line losses, system balance and reserve issues, robustness and power quality.

Distribution has traditionally been seen as the 'junior' partner to transmission, (Nolan, 2015) fed from the much larger arteries of the transmission network and operated 'passively' i.e. without a need to forecast and actively manage network flows (WPD, 2017a). However, as distributed generation grows and large scale power station capacity falls, this will have a major impact on the roles of the GB Transmission System Operator (TSO) and the Distribution Network Operators (DNOs), with the DNOs potentially becoming major operators in procurement of services and system balancing in future (Nolan, 2015).

Distributed generation could also have a major impact on the cost of balancing the networks. In 2016-17 National Grid's costs of balancing the electricity system increased by around £250 million, to over £1.1 billion (Ofgem, 2017m). However analysis undertaken by Imperial College (Shakoor *et al.*, 2017) suggests that reduced system operation costs of between 25% and 40% could be achieved through the deployment of new, cheaper, flexibility sources connected at the distribution level rather than by conventional generation.

Therefore, distributed generation can be exploited to establish a more efficient, cleaner and cheaper electricity system given the right regulatory environment. Distributed energy resources (DER) such as storage and small renewable and low carbon technologies have the potential to provide downward or upward adjustment to the system, contributing towards balanced power (Ruester *et al.*, 2014); and flexibility services could be utilised by the DNOs to solve capacity and voltage constraints on the networks, deferring or even avoiding expensive grid reinforcement costs (Vallés *et al.*, 2016).

These changes have the potential to transform the current market structure of electricity trading and introduce new services and markets. Research undertaken by Navigant suggests that by 2030 distribution grids will have completely changed their operations to incorporate the rise in DER, with customers trading their self-generated power on the open market (Ravens and Lawrence, 2017). New emergent services can include dynamic pricing, aggregation, peer-to-peer trading and various demand side management options which can help to overcome system balancing issues; whilst new markets such as local energy markets can provide a route for smaller providers to aggregate in the delivery of these services.

To enable this transition from a top-down, one-way system to a much more complex distributed network, the roles of key market actors will need to evolve (BEIS and Ofgem, 2017a). A number of activities are already being progressed by BEIS, Ofgem, National Grid, the ENA[2] and the DNOs as will be discussed in Section 4. However, there is much to be determined over the next few years in relation to the current monopoly roles of the TSO and the DNOs (BEIS and Ofgem, 2017a); as well as the role of suppliers, aggregators and the emergent roles that can be established by new innovative market entrants.

2.1 CHANGING THE SUPPLIER HUB MODEL

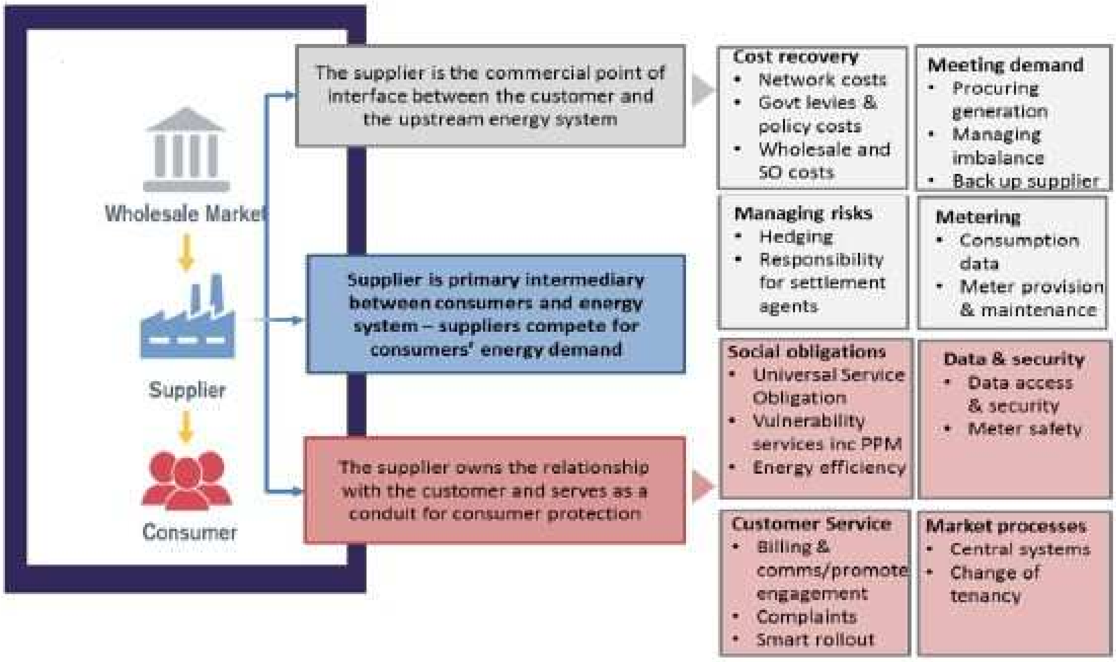
One major barrier to the development of local energy markets is the current role of suppliers. When the energy industry was privatised in the late 1980s, the market was designed with suppliers as the core intermediary between customers and the energy system, in what is known as the 'supplier hub' model. The current market arrangements have evolved and developed around this principle and the supplier's role is now entrenched in legal frameworks, licensing arrangements, and industry codes, regulations and rules (Ofgem, 2017e).

However, a different market structure will be needed for an industry that transforms from a top-down system to one that fully enables distributed generation and peer-to-peer (P2P) trading with a small amount of high voltage interconnection between distributed generation and smaller more localised networks.

Ofgem issued a call for evidence (CfE) on the future of supply market arrangements on 14 November 2017 to inform its consideration of whether the current supplier hub model is still fit for purpose in light of innovative changes to electricity markets. With potential changes to the roles of other market actors such as the DNOs, the SO and aggregators; plus the emerging innovators such as the Centrica LEM project, Ofgem suggest that the supplier hub model may no longer be fit for purpose and provides a barrier for new trading arrangements, such as P2P to enter the marketplace.

[2] Energy Network Association

Figure 1 Current Supplier Role



Source: (Ofgem, 2017e)

As the entire industry currently operates on the assumption that a single supplier connects to the active import data from a single meter, and a single supplier connects to the active export data; a requirement for more than one supplier to access data from a single individual meter would require significant industry system changes for settlement (Elexon, 2017a).

Elexon stated in response to the CfE that radical and strategic change to the current energy market arrangements need to happen, however, in order to allow innovative approaches to emerge and to allow for the potential contractual relationships the consumer will have in future with both existing/new energy supplier(s), and new service/technology providers (Elexon, 2017a).

Change to the supplier hub model would therefore be an enabler for the LEM. Allowing customers to have more than one energy supplier at a time; allowing customers to trade their excess generation between themselves without transacting through a licensed energy supplier; and allowing customers to sell their generation to whomever they chose would open up access to new distributed markets and services, such as P2P, which are currently inaccessible due to the existing regulation.

3. REGULATORY BARRIERS IN EXISTING MARKETS

SECTION OVERVIEW

To date the main route to trade flexibility in GB is at the national level through various procurement mechanisms, and across different time horizons. However, these markets were established on the presumption of large scale generation, connected at the transmission level, meeting most of GBs electricity demand and therefore there are existing access problems for smaller generators and flexibility providers. Indeed where these technologies are successfully accessing these markets their percentage share can be very low. Access to these existing markets are therefore a valuable revenue stream for local assets until localised trading arrangements such as the LEM have been developed as discussed later in this report (Section 6).

3.1 GB MARKETS AND TECHNOLOGIES

The main national markets are:

- **Capacity Market**: capacity contracts are awarded through *auctions* which are held at 4 years and 1 year ahead of delivery.
- **Wholesale Energy Market**: *bilateral trading* takes place from several years ahead up to Gate Closure, one hour prior to transmission (T-1 hour).
- **Balancing Market**: National Grid as System Operator (SO) maintains demand and supply balance post Gate Closure, through a system of *bids and offers* in Balancing Mechanism Units (BMUs).
- **Ancillary (balancing) services**: the SO also ensures that supply meets demand at all times and that system frequency remains within statutory limits. There are currently several different ancillary service routes, which are procured in different ways (i.e. *tendered or bilateral trading*). (Shakoor *et al.*, 2017).

These national markets can be accessed by a number of different technologies. Table 1 GB Markets & Technologies shows the technologies that are currently providing these services (√) and those that are technically capable but which are restricted (*). Restrictions could be through commercial constraints, market limitations or lack of incentives (Shakoor *et al.*, 2017). However even where these technologies are already providing services, their market share may still form a very small percentage e.g. demand side response (DSR) only had a 6% share of ancillary services in 2016 (PA Consulting Group, 2016). As National Grid is the main contractor of DSR services in GB at present (Lo, 2017) increased access to the Balancing Market and ancillary services will be critical to DSRs success until such time as other new markets become accessible.

LEM participants will be utilising a variety of renewable and low carbon technologies (LCT) such as CHP, batteries, solar and wind as well as offering DSR solutions. Table 1 shows that these technologies are capable of accessing these markets (and in some cases they are already to a greater or lesser extent) but that there are limitations to be overcome to trade across all of them.

The focus of this report is to determine whether these limitations are due to a market or regulatory barrier to access. It is not within this report's remit to discuss any technical or operational limitations associated with these technologies.

Table 1 GB Markets & Technologies

Technology	Capacity Market	Wholesale Market	Balancing Market	Main Ancillary Services (2017)			
				STOR	Fast Reserve	Frequency Response	Enhanced Frequency Response
Coal	√	√	√			√	
Nuclear	√	√	*			*	
Gas - CCGT	√	√	√	√	*	√	
Gas - OCGT	√	√	√	√	*	√	
CHP	√	√	√	√	*	√	
Biomass	√	√	√	*	*	√	
Engines	√	√	√	√	√		
Wind	*	√	√	√	*	√	
Solar - PV		√	*		*	*	
Solar - CSP	*	*	*	*	*	*	
Hydro (reservoir)	√	√	√	√	*	√	
Marine	*	*	*	*	*	*	
Hydro (pump storage)	√	√	√	√	√	√	
Storage (batteries)	√	√	*	√	*	√	√
DSR	√	*	√	√	√	√	*

√ Technology is providing the service

*Technology can potentially provide the service but is currently restricted due to economic or market limitations, or requires some technical improvements

Blank cells indicate absence of evidence to map technologies onto the service

Source: (Poyry analysis as shown in Shakoor *et al.*, 2017)

3.2 ANCILLARY SERVICES

Table 1 above shows the main ancillary services called upon by the TSO, but in effect there have been a plethora of different services utilised to date which has caused several issues for new entrants and flexibility providers (BEIS and Ofgem, 2017b). Issues identified by consultees during BEIS and Ofgem's 'Call for Evidence' (CfE) in November 2016 include a lack of transparency in different products; overlapping of products with different specifications and procurement processes; short contract lengths and procurement processes not being market-based i.e. bilaterally traded (BEIS and Ofgem, 2017b p.19). This is recognised by National Grid:

> "In many cases the requirement is being driven by several system issues which interact, and this interaction is not communicated to the market in advance of assessment. Furthermore, requirements can change from tender to tender as a result of variations in some of the underlying system issues with little or no explanation to tendering parties. These issues together result in confusion over why certain tenders have been accepted and others have not, and also uncertainty over the stability and long-term sustainability of our markets" (National Grid, 2017f)

A range of respondents to the CfE called for the reform of ancillary services in order to ease these difficulties. Requests included a 'blended' approach to procurement whereby multiple services were procured at the same time instead of trying to avoid the fragmentation of there currently being several different time windows over which different revenue streams could be secured (BEIS and Ofgem, 2017b p.27-28).

In June 2017 National Grid published their 'System Needs and Product Strategy' (SNAPS) document (National Grid, 2017f) which sought to address some of these issues by proposing to reduce the array of ancillary services to 5 core areas of system need, to simplify access for demand side response and storage providers:

1. Inertia and Rate of Change of Frequency (RoCoF)
2. Frequency Response
3. Reserve
4. Reactive Power
5. Black Start

National Grid stated that they need to *create a marketplace for balancing that encourages* ***new and existing providers, and all new technology types and which opens up competition on a level playing field*** (National Grid, 2017f). The frequency response market in particular is expected to expand, becoming increasingly important as further renewable capacity comes online and existing coal and gas plants close (Cornwall Insight, 2017).

The SNAPS consultation response document published in September 17 (National Grid, 2017e) showed that consultees raised similar issues to those raised in Ofgem's CfE, i.e. the need for greater transparency of the TSO's day-to-day actions; a reduction in barriers to entry for new providers and more detail needed on the proposed simplification of products.

Stacking of services was seen as important by 95.6% of respondents (National Grid, 2017e) and was also identified as a key issue through the Government's CfE (BEIS and Ofgem, 2017a). Respondents thought that aligning procurement timescales between products would help with unlocking the potential for stacking. Stacking of services would allow flexibility providers to hold contracts to provide several different ancillary services (including transmission and distribution level services), rather than just one contract for a specific product. Stacking could also mean that providers may receive more than one payment per transaction event, if that event met more than one contract requirement at the same time. It will also allow providers to participate in the capacity market as well as ancillary services. Stacking will be important for the LEM in allowing access to several different revenue streams for customers' flexibility provision, including new local products as well as access to traditional markets.

A mix of both short-term markets and longer-term contracts was favoured by 61.7% of respondents, while 21.2% favoured short-term markets only. Only 17% of parties favoured long-term contracts only. Although both options (short term and long term) have their pros and cons, respondents felt that a mixture of both would be the most financially advantageous to both sides:

> "Short term markets can remove forecasting risk as well as allow for changes to parties' commercial strategies. On the other hand, short term markets may not increase investor confidence. Longer term contracts would deliver a much lower cost of capital for investment. On the other hand, longer term contracts may create higher costs of balancing for the end consumer by locking in technologies which may be cheaper in the future or lock the SO in a procurement contract which may no longer be relevant as the system needs change over time" (National Grid, 2017e).

National Grid are also facilitating a stakeholder-led programme 'Power Responsive' (National Grid, 2017c) to stimulate increased participation in DSR and storage by 2020. One of the outcomes for the programme will be to ensure that DSR has equal opportunity with supply in contributing to balancing the system. To date Power Responsive has been focused on I&C customers only, but from 2018 onwards it will also involve the smaller non-domestic and domestic sector. The TSO has an ambition to procure 30-50% of its balancing services by 2020 through demand side measures (BEIS and Ofgem, 2016), which to-date stands at just 6% (PA Consulting Group, 2016).

The ambition is to realise more non-wire alternatives (NWA) for system balancing instead of building extra capacity as usual. Flexibility services from DER are increasingly being used to mitigate both network management and energy balancing issues. For instance in 2017 National Grid procured over 200MW of Enhanced Frequency Response (EFR) from battery storage (National Grid, 2017b).

Aggregators enable the participation of small, individual loads in the ancillary services market. This not only increases the level of participation by DSR, but also provides reliability benefits through diversity. PA Consulting estimates that 82% of DSR participating in the STOR product is provided through aggregators (CRA, 2017a).

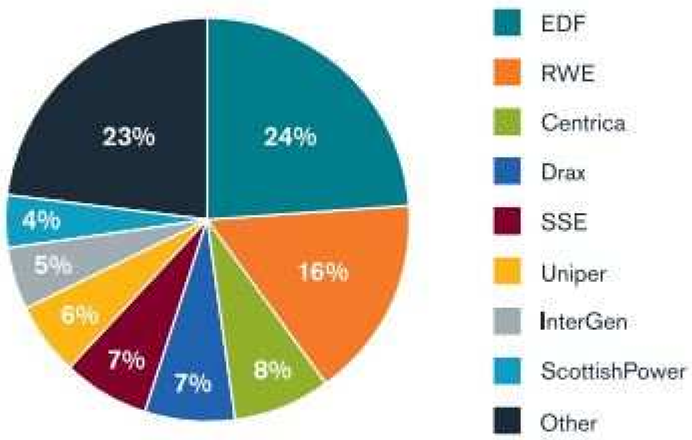
National Grid launched their 'Product Roadmap' in December 2017 which incorporates the updates to the SNAPS consultation and sets out their first steps towards rationalising and simplifying frequency response and reserve products. Several frequency response products will be removed, including EFR, (although existing contracts won't be cancelled) but the new standardised products should be easier for DSR providers to access and exclusivity clauses will be reviewed. Tenders can be made for short-term requirements on a monthly basis and longer-term requirements on a quarterly basis; and trial auctions will also commence from late 2018 to establish whether auctions are seen as an easier vehicle for DSR providers to access these revenue streams rather than through tendering.

3.3 WHOLESALE MARKET

The wholesale electricity market is seen as particularly difficult for small generators to enter directly due to the costs involved with registering, licensing and trading in this market. Some of these costs are related to rules concerning the Balancing Market (BM) which are discussed in more detail in 3.4.

The wholesale market is moderately concentrated, with eight generators providing three-quarters of metered volumes in 2016 as shown in Figure 3.

Figure 2 Market shares of wholesale supply (2016)



Source: (Ofgem, 2017m)

Ofgem introduced new rules to accessing the wholesale market in 2014 to create a 'more level playing field' for independent suppliers and generators, to increase liquidity in the market. In terms of independent generators, the rule changes were supposed to enable them to compete more effectively against the Big 6 (Ofgem, 2013) through ensuring the availability of a range of longer-term products, to support hedging of risk of exposure to large changes to prices (Ofgem, 2014). Hedging is seen as important for independent generators in being certain of the price they will get for selling their power.

However, as can be seen by Figure 2 this has had little impact to date on the wholesale market, due to several other inhibiting factors as discussed below.

There are currently two routes of entry for small generators to the wholesale market:-

- Central Volume Allocation (CVA) agreements which allows generators to access the market ***directly***, and
- Supplier Volume Allocation (SVA) agreements which involve partnering with a licensed supplier, via a Power Purchase Agreement (PPA) i.e. ***indirectly***.

CVA REQUIREMENTS

In order to assist with smaller generators accessing the wholesale market directly, and to create more liquidity in the market, APX reduced the clip size on the Power UK Continuous Market from 1.0 MW to 0.1 MW in 2011 and reduced the minimum collateral requirements. At the same time, the minimum order size was also lowered to 0.1 MW to enable smaller suppliers to access the Continuous Market (APX Power UK, 2011). However the Power UK Auction Market was not changed and the minimum clip size and order size therefore remains at 1MWh in this market.

To qualify for CVA under the Balancing and Settlement Code (BSC) requirements there are still many steps to go through and the costs are likely to outweigh any potential benefit. These include:

The CVA Qualification process

- Accession Form
- £500 Accession Fee
- Accession Agreement
- Authorised signatories (BSCP38/5.1 and Director's letter)
- Order Communications Line Request
- CVA Testing
- Funds Accession Form BSCP301/04a
- Credit Contacts
- Party Registration (BSCP65/01)
- Party Agent Registration (BSCP71/05)
- BM Unit Registration (BSCP15/4.1)
- £250 per month BSC membership fee
- £100 per month BMU registration fee

Source: Elexon 2017 (prices correct as of Dec 2017)

However, the monthly fees shown above, can be minimal in comparison to the costs of paying imbalance fees (should the generator not be able to fulfil its traded volume at gate closure) or the cost of buying any additional generation volume from a third party (in order to fulfil the requirement at gate closure). There are also huge costs involved in operating a trading team. The risks and requirements are therefore hugely weighted against small generators.

As Table 1 showed, DSR is not at present directly accessing the wholesale market, although it technically has the potential to do so. This is due to the fact that there is no mechanism for DSR in making bids and offers in the BM as discussed below. In addition, independent aggregators currently do not have direct access to the Balancing Mechanism and the wholesale electricity market (Ofgem, 2017g).

Therefore, at present, for DSR to access the wholesale market, it would need to be traded ***indirectly*** through a supplier as per the SVA route below or through imbalance trading i.e. suppliers may have an incentive to activate DSR in order to improve their position in the BM. This may also create additional revenues to be shared with DSR providers and so potentially leads to all parties having an incentive to facilitate DSR (CRA, 2017a).

SVA

The alternative to CVA is to partner with a licensed supplier who would register the generation asset on the generator's behalf. The supplier would either register the asset as a stand-alone Balancing Mechanism Unit (BMU), at a charge of £100 per month, or would register it under their existing BMUs (where it would count as negative demand). (See 3.4 below for more detail.)

Using this route however generators can only sell their power via their licensed supplier, usually through a PPA. This would therefore exclude DER from selling to both local buyers and on the Wholesale Market; although this could potentially change in future depending on Ofgem's decision as to whether to make changes to the supplier hub model (Section 2.1).

PPAs are normally offered for any generation over 250 KW, whilst generation under 250KW would be eligible for Feed in Tariff (FiT) payments from the supplier.

3.4 BALANCING MARKET

The BM is critical to balancing the system after gate closure: T-1 hour (one hour before transmission) when the SO takes control.

National Grid accepts Bids and Offers in real-time, and as required, to match supply and demand in each half hour depending on whether they need to increase or reduce electricity generation (Elexon, 2017f). BMUs are used as units of trade within the BM. Each BMU is a collection of plant and/or apparatus, and is considered the smallest grouping that can be independently metered for Settlement (Elexon, 2017e).

The offer of services to the BM is optional and not all generators participate, indeed the number of participants is reducing (National Grid, 2017f). This lowers competition in the market and makes energy balancing actions more expensive and the imbalance price more volatile.

Currently there is no provision in the design of the BM for explicit DSR. In practice it can only be provided by the *supplier* of the DSR-provider. This is because there is no mechanism for making bids and offers for a customer's potential demand, since there is no baselining of a customer's demand against which such bids/offers may be assessed in order to monitor delivery. As a result, DSR is limited to provision by suppliers that may activate DSR in their customers (hence the recent decision for Flexitricity to apply for a suppliers licence) or via aggregators who sell to suppliers (CRA, 2017a).

BM participation is also seen as particularly difficult for smaller embedded generators to access due to the volumes required by the SO, administrative costs and compliance with electricity licensing codes. Smaller generators are currently not able to aggregate generators at multiple sites into a single BMU, making it difficult for them to compete with larger power stations in the BM. The SO has operational issues with despatching smaller plants (Elexon, 2017d) and so allowing embedded generators to aggregate themselves into larger BMUs would give them more opportunity to participate in the BM, whilst also giving the SO access to further plant for system balancing purposes.

However, European balancing project TERRE could indirectly ease access to the BM for independent DSR providers and smaller generators, by requiring modifications to the Balancing and Settlement Code (BSC) in order for GB to comply with Project TERRE requirements.

TERRE requirements state that *DSR must be allowed to compete on a level playing field with traditional flexibility providers* (AAMHE *et al.*, 2016).

Modification **P344** (Elexon, 2017b) to the Balancing and Settlement Code (BSC) seeks to align the BSC with TERRE requirements in order for the project to be implemented in 2018. In addition, Modification **P355** (Elexon, 2017c) **'Introduction of a BM Lite Balancing Mechanism**' raised by PeakGen in June 2017 builds on the Project TERRE concept by proposing that smaller generators should be allowed to aggregate into larger BMUs for use in the BM.

PeakGen are strongly of the view that it is discriminatory that suppliers have access to aggregation options that are not available to embedded generators. If approved, Modification P355 would enable smaller generators to aggregate themselves into larger BMUs (suggested at between 5 and 200MW) which could be dispatched by the TSO. By allowing these sites into the BM, it would significantly increase the pool of generation open to National Grid and bring increased competition. At present however DSR and DSR aggregators have been excluded from Modification P355, but PeakGen have stated that these should be considered alongside P355 (Elexon, 2017d).

With the increased prevalence of DER in the energy market there is also an argument to be made for tighter timescales to gate closure. Balancing at 15 minutes or 10 minutes to gate closure would allow for a more granular and flexible market. In New Zealand, the SO applies a Reserve Management Tool to continually identify risk to the demand-supply balance in the system. It then determines an optimised portfolio of flexibility services and ensures its provision through the ancillary services market. Providers are then able to bid in reserve products right up to gate closure (Shakoor *et al.*, 2017).

3.5 CAPACITY MARKET

Whilst the Capacity Market (CM) does not explicitly rule out renewable energy technologies from bidding in, the CM rules state that you cannot bid in if you receive support under the Renewables Obligation (RO) or the Contracts for Difference (CfD) schemes; which automatically rules out most renewable technologies.

Even where these technologies can bid into CM auctions the CM rules require availability under strict terms i.e. they are given four hours of warning after which they are required to generate immediately on demand. Though a typical dispatch is only expected to last for 30 minutes, participants should be able to run their assets for up to four hours in accordance with the CM rules (Lockwood, 2017).

There have also been issues identified with access to the CM for both DSR and storage (BEIS and Ofgem, 2016). The 2016/17 T-4 auction was the first time that ***battery*** storage had agreements awarded (around 500MW at a clearance price of £22.50 per kW) and although DSR saw significant growth (up from 450MW in the 2015 auction to around 1.4 GW) storage and DSR still accounted for only 6.11% and 2.69% respectively (National Grid, 2017d).

However in the 2017/18 T-4 auction, only 153MW of battery storage capacity was contracted, due to developers unwilling or unable to accept contracts at the astonishingly low clearance price of £8.40 per kW; whilst DSR contracts stayed relatively stable at 1.2GW (Business Green, 2018).

The participation of aggregators in the CM has been important in enabling the participation of individual DSR resources that would not meet the minimum capacity requirement on their own and indeed most of the awarded DSR agreements have been via aggregators (*ibid*). The minimum capacity required to participate in the main CM auction is 2 MW and 500 kW for the 2016/17 TA auction (CRA, 2017a).

DSR providers are only awarded one-year contracts in the CM which has been seen as a principal concern of aggregators as it can affect their access to finance (CRA, 2017a). On the one hand, whilst short term contracts may give DSR providers more flexibility to provide other services (by not being tied into a long-term agreement) longer term contracts would be attractive if providers were able to stack products across other service areas, allowing access to several different revenue streams. BEIS /Ofgem signalled in the Smart Systems and Flexibility Plan that they will allow stacking (BEIS and Ofgem, 2017a).

The existence of the CM and the high volumes of capacity procured (up to four years in advance) will have both a direct and an indirect impact on any local energy market, including:

- By determining a strict reliability standard in advance this can lead to over-contracting of capacity[3], thereby limiting the scope for ancillary services (Reserve) to provide peak demand
- The CM is keeping old plant operating which will prove direct competition for local assets looking to provide ancillary services
- The CM has dampened wholesale electricity prices
- By relying on the CM to manage future perceived problems it stifles investment and development of other low carbon solutions to the problem such as DSR, storage and demand reduction.

The CM can therefore be seen as a backward looking policy in which opportunities for supporting the emergence of a new energy system has been missed (Lockwood, 2017).

There is therefore an argument to be made over whether the CM should be shrunk to allow flexibility to provide real-time balancing of the system[4]. This argument will become more strident as distributed generation grows, and demand and demand volatility increases with higher adoption of EVs and other domestic technologies such as heat pumps.

[3] The reliability standard for the Capacity Market is set at 3 hours per year, whereas National Grid predicts that the loss of load expectation (LOLE) for Winter 2017/18, i.e. the likelihood of the lights going out, will be 0.01 hours (Lockwood, 2018).

[4] On 03/01/2018 National Grid recommended that capacity for both the T-1 2018/19 and T-4 2021/22 CM auctions be cut, by 1.1 GW and 600 MW respectively (Stoker, 2018).

SECTION SUMMARY

These existing markets were established against a background of large scale generators connected at the transmission level, providing most of GBs electricity supply. As large fossil fueled generators close and more renewable technologies are connected at the distribution level these markets should be adapted to enable access from DER and DSR providers. Smaller scale generation may also need to be aggregated to achieve the high volumes of electricity needed to meet market requirements, such as through independent aggregators.

Barriers to access therefore need to be removed for DER and DSR providers and different ways of trading need to be examined in order to gain insight into which mechanisms are most useful; whether that be through aligning timescales for procurement or offering different procurement approaches such as bilateral trading or auctions. The barriers identified are shown in Table 2.

Table 2 Barriers to Existing Markets

Barrier	Possible Solution
ANCILLARY SERVICES	
Difficult for smaller generators, DSR and storage to access	Rationalisation of services to simplify process and align timescales for tendering. National Grid will also trial auctions from late 2018.
Too many products	Product rationalisation taking place currently
Multiple timelines for procurement	Timelines to become aligned
Stacking of contracts	National Grid have stated that stacking across products will be possible, which will increase financial viability for small generators / DSR providers.
WHOLESALE MARKET	
Difficult for small generators to access	The clip size in the Power UK Continuous Market was reduced to 0.1 MW to assist with smaller generators accessing the wholesale market. However, the costs, regulations and licensing requirements are prohibitive to many small generators. If they choose the SVA route then they can only trade with one licensed supplier. This may be overcome through any changes to the Supplier Hub model. Additionally Modification P355 (see BM section) may be helpful in overcoming access to the BM requirement.

No provision for explicit DSR in the wholesale market	DSR currently can only be provided by the *supplier* of the DSR-provider as there is no mechanism for making bids and offers for a customer's potential demand, since there is no baselining of a customer's demand against which such bids/offers may be assessed. However Modification P344 to the BSC could be helpful.
Lack of access for aggregators	Create a new route for independent aggregators to access the BM. Will need modifications to the BSC as per BM below.
BALANCING MARKET	
Difficult for smaller generators to access the BM	Modifications P344 & P355 'Introduction of a BM Lite Balancing Mechanism' should be helpful in this respect.
Lack of access for Aggregators & DSR	Modification P344 brings the BSC in line with Project TERRE requirements which states that DSR should have a level playing field with other forms of generation in accessing the BM. Also, aggregators should be considered alongside P355 (although they are currently excluded).
CAPACITY MARKET	
Access to the CM for RES	RES receiving RO or CfD payments are ineligible to bid into the CM – which automatically rules out the majority of RES generation.
Access to the CM for both DSR and Storage	Although DSR and storage are accessing CM their respective share percentages are still very low. Decision to be made over whether their share % should be increased, or whether it is better to use these resources for real-time balancing of the system.
Restrictions on the ability to stack revenues from ancillary services alongside CM	Allow stacking of revenues between the CM and ancillary services. Review exclusivity clauses.
Aggregators can't change the portfolio of DSR participants which make up a CM unit. Therefore, if one participant withdraws the whole contract is nullified	Enable asset reallocation by DSR providers.

By determining a strict reliability standard in advance this can lead to over-contracting of capacity, thereby limiting the scope for ancillary services (Reserve) to provide peak demand	Reduce reliability standard and / or allow flexibility to provide real-time balancing.
The CM is keeping old plant in operation which will prove direct competition for local assets.	BEIS / Ofgem need to consider what types of generation they are trying to encourage. With many contracts being awarded to existing fossil fueled plants they are prolonging the life of these generators to the detriment of flexibility providers. The CM Rules need to be amended to discourage this.
The recent falling clearing prices of CM contracts (2018 auctions) is proving unattractive for storage providers	As above – review CM Rules regarding old 'dirty' plant.
By relying on the CM to manage future perceived problems it stifles investment and development of other low carbon solutions to the problem such as DSR, storage and demand reduction	As above – review CM Rules regarding old 'dirty' plant.

4. CHANGING ROLES OF NETWORK OPERATORS

SECTION OVERVIEW

To further enable the transition from a top-down, one-way system to a more complex distributed network, the roles of key market actors will also need to evolve (BEIS and Ofgem, 2017a). This section outlines the changes that are already in progress with the TSO and the DNOs and how these changes can potentially unlock new flexibility markets, such as Centrica's LEM, at the distribution level.

4.1 THE TRANSMISSION SYSTEM OPERATOR

National Grid are in the process of reorganising their business to separate the role of the TSO within the National Grid Group (NGG), and to set up a new legally separate company (with a separate licence) to carry out its electricity system operator function within NGG (Ofgem, 2017d).

In January 2017 Ofgem led a consultation on the 'Future Arrangements for the ESO' (Ofgem, 2017c) which was followed by a consultation response in August 2017 (Ofgem, 2017d) along with National Grid's 'Industry transformation: The changing role of the electricity System Operator' (National Grid, 2017a).

Ofgem's thoughts are that a more independent TSO should be able to work more closely with the DNOs to create a 'whole system view' and identify and help speed up connections for new generation (Ofgem, 2017d). But this all depends on how the roles and responsibilities between transmission and network operators unfold. The European Commission proposes through the 'Winter Package' (European Commission, 2016b) to strengthen the legislative framework for cooperation between DNOs and TSOs to ensure that all necessary information and data is shared in order to ensure cost-efficiency and secure operation of the networks (Hancher and Winters, 2017).

As more distributed generation emerges the traditional distinction between transmission and distribution will become increasingly blurred. Currently distributed generation is considered as 'negative' demand for transmission flows. However, as the percentage of generation increases at the distribution network level, this cannot continue to be perceived as negative. Rather it needs to be thought of as a positive asset for both the coordination and balancing of the distribution networks. This is a new role for both transmission and distribution operators.

Elexon have stated that the blurring of the distinction between transmission and distribution could remove the concept of Grid Supply Points, as there would be no Transmission Grid to Distribution transition point. Elexon claim that the movement of settlement down towards individual consumer level, from the current Grid Supply Point level, would be a fundamental market change, which would act as a key enabler to many innovative ideas (Elexon, 2017a).

However, an increase in the demand for balancing services will pose challenges for National Grid which has limited visibility of demand and distributed generation (Watson, Ekins and Wright, 2016). Therefore whilst the TSO may hope to remain at the forefront of electricity balancing as GB moves towards a more decentralised energy market (National Grid, 2017a) there is great potential for the switching of roles in system balancing, with the distribution networks becoming increasingly more important (Nolan, 2015).

National Grid's 'Industry Transformation' document explains how the TSO sits at the 'heart' of the electricity system (National Grid, 2017a) and the document sets out four workstreams to enable the transition towards a distributed electricity future with the TSO still at the forefront of balancing supply and demand across the entire network. The workstreams are:

- **Flexibility** – relooking at the procurement of ancillary / flexibility services to aid transparency and market entry (in line with the SNAPS document outlined in Section 3.2)
- **Network Competition** – including working with the DNOs to identify distribution network solutions and non-traditional solutions (i.e. storage, DSR) where this proves to be cost-effective
- **Whole System** – working with the DNOs on the Open Networks project (see Section 4.2) and other industry partners to trial different ways of buying and selling energy and services (such as the LEM).
- **Level Playing Field** – working with Ofgem in reforming network charging and access arrangements for distributed energy providers (see Section 5).

Whilst the TSO may wish to remain at the 'heart' of the electricity system in the near future, these four workstreams show that National Grid recognise that the way in which they currently operate will need to change. This should be beneficial to DER operators and the LEM as new routes to market should be facilitated and encouraged. However, it is unclear how much power the TSO will hold in the future and how far they are willing to help enable change and cooperate with potential rival organisations over access to data and potential sharing of operating platforms.

It is possible that the role of the TSO could diminish to the point of managing low level baseload requirements and evening peaks only (Nolan, 2015). Ultimately it is for BEIS and Ofgem to provide clarity on the future roles and responsibilities of the TSO and the DSOs by clearly defining these roles and responsibilities and through establishing an appropriate regulatory and incentives framework (Shakoor *et al.*, 2017). BEIS and Ofgem therefore need to listen to a range of energy industry voices in defining this future rather than just the voices of the networks themselves as will be discussed in the next section.

4.2 THE DISTRIBUTION NETWORK OPERATORS

The changing role of the DNOs can be seen as one of the most critical factors determining whether, and how, small generators and DER providers are able to access new revenue streams and localised markets. This section outlines the changes that are in progress and how these changes can unlock such markets. This section also highlights the work of the Open Networks Project in helping to create and establish the new roles and responsibilities between network operators, and the role of RIIO in financing the networks and stimulating network innovation through dedicated funding pots.

FROM DNO TO DSO

Until recently the DNOs have been seen as largely 'passive' in their operations – facilitating the one way flow of electricity to the consumer. However, an increase in distributed generation connected directly to these networks requires increasing enablement of bi-directional power flows, and the DNOs are now faced with a number of issues in network management, including increased occurrences of voltage deviations, line losses, protection sensitivity, system balancing and reserve issues (Ramos *et al.*, 2016).

To meet the needs of this more decentralised future energy system, the GB DNOs are beginning to commence a transition to becoming DSOs – distribution **system** operators – during the current RIIO-ED1 price control period (2015-2023). The Energy Networks Association (ENA) has defined a DSO as: -

- securely operating and developing an active distribution system comprising networks, demand, generation and other flexible distributed energy resources (DER)
- acting as a neutral facilitator of an open and accessible market, enabling competitive access to markets and the optimal use of DER on distribution networks to deliver security, sustainability and affordability in the support of whole system optimisation
- enabling customers to be both producers and consumers; enabling customer access, customer choice and great customer service (ENA, 2017b).

The Energy Policy Group at the University of Exeter broadly agree with this definition[5] in that it moves the DNO away from the passive role of 'fit and forget' (Ramos *et al.*, 2016) and transforms their role into 'active' system coordinators (Bray *et al.*, 2017). Although the European Commission proposes to strengthen the legislative framework for DSOs through the Winter Package, this is proving challenging as the DSOs current roles are divergent across all Member States (Hancher and Winters, 2017). In essence though, regulators need to ensure that all DSOs have adequate financial incentives to innovate and upgrade their networks, to procure and connect distributed generation and to contract with other service providers, as well as to deal with local congestion management issues (European Commission, 2016a) and (Hancher and Winters, 2017). In GB, the balance between what the DSOs will operate themselves and what they will procure from the market is still to be determined. New flexibility services

[5] Overall, however, the EPG prefers the Distribution Service Provider (DSP) function as set out by the IGov project and outlined here: http://projects.exeter.ac.uk/igov/submission-comments-on-wpds-dso-transition-consultation-document/

will emerge over the next few years so the DSOs will need to anticipate and enable their route to market.

This change should lead to wider procurement of distribution level services to manage local constraints and system balancing, creating new flexibility markets for local distributed energy providers to trade in. The Cornwall LEM is such a market at the distribution level, enabling network parties and DER to buy and sell flexibility services.

The presence of flexibility markets, operating at the distribution network level and improving local balancing, may also enable additional renewable generators to connect to the network in locations which were previously considered to be constrained.

THE ROLE OF THE OPEN NETWORKS PROJECT

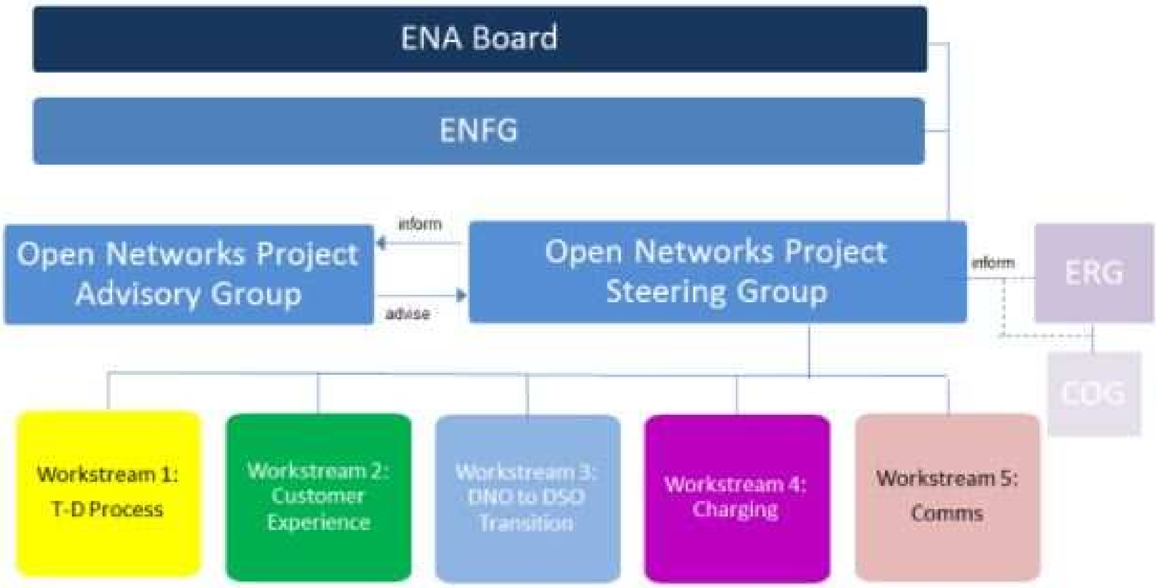
The ENA is leading on the 'Open Networks Project' which is examining DNO to DSO transitions as part of its remit, as well as advising on the future coordination scheme for the TSO and the DSOs in the procurement and dispatch of DER. The coordination scheme which is eventually chosen will not only determine the responsibilities of the system operators towards each other but will also determine their responsibilities towards third parties (i.e. suppliers, aggregators, DER providers etc.) (Hancher and Winters, 2017). This work is of strategic importance to the future of the GB energy system and it should therefore be questioned whether the ENA is the correct body to be leading on this. Although the network operators will have the technical experience and expertise to input to the project they also have a vested interest in the outcomes of the project through their current role as monopoly stakeholders. The project does also have input from BEIS, Ofgem, academics, trade associations and NGOs; giving the project a degree of legitimacy in decision making, but it should ultimately be for Government to determine the route which will best lead to the smart, flexible energy system required.

Lessons could be learnt here from California and New York (as discussed further in Section 6.2) which are both well advanced in their energy transitions. New York State's Reforming the Energy Vision, the New York REV (NYPDS, 2014), was launched in 2014 on the premise that the existing energy governance was no longer fit for purpose and had to be completely rewritten to create a decentralised energy system with a strong focus on distribution level services, operated through active Distribution Service Providers (DSPs). The DSP is envisaged in New York as both the local System Operator and as the platform through which DER providers can sell to customers via new markets to create value for both customers and the system. The DSP serves as a multi-way retail-level dispatcher to the grid (distribution and transmission) of both energy and system services, supplied not only by traditional power plants, but also by a vastly expanded fleet of DER (Mitchell, 2016).

Meanwhile in GB, the Open Networks project is investigating: what is the scope of activity that a DSO should carry out to manage constraints on the network; what should the role of the DSO be within the energy market; and how should this new entity interact with other market participants (ENA, 2017c)?

The project is split across five workstreams see Figure 3.

Figure 3 Open Networks Workstreams



Source: (ENA, 2017d)

Workstream 1 (T-D Process) issued a consultation document in August 2017 'Commercial Principles for Contracted Flexibility' (ENA, 2017d) which put forward six different models for coordinating the procurement and dispatch of DER services as shown in Table 3.

Table 3 ENA's 6 Models for coordinating DER

Option	Assessment
1. Status Quo (which is seen as unsustainable in the long term)	Option 1 is recognised by the ENA as not being a viable long term solution if GB moves to a more flexible energy system.
2. Managing Distribution Network Impact - similar to Status Quo but with a direct link to the DSO so that impact can be understood	Option 2 is a slight enhancement on Option 1 in that it incorporates the provision of DER on distribution networks, but it is procured only by the SO. This will have the effect of reducing the amount of services that local assets can offer and does not overcome network constraint management issues or provide for local granularity.
3. SO coordinates – procuring for the needs of SO and DSO	Option 3 may be the most conventional model in the shorter term due to the SOs existing procurement, call-off and settlement processes already being in place. It also means that one organisation is procuring / dispatching on a nationwide basis, rather than 6 DSOs procuring separately for their own needs. However it is still a top down approach and may not include the granularity anticipated for full DER market availability.

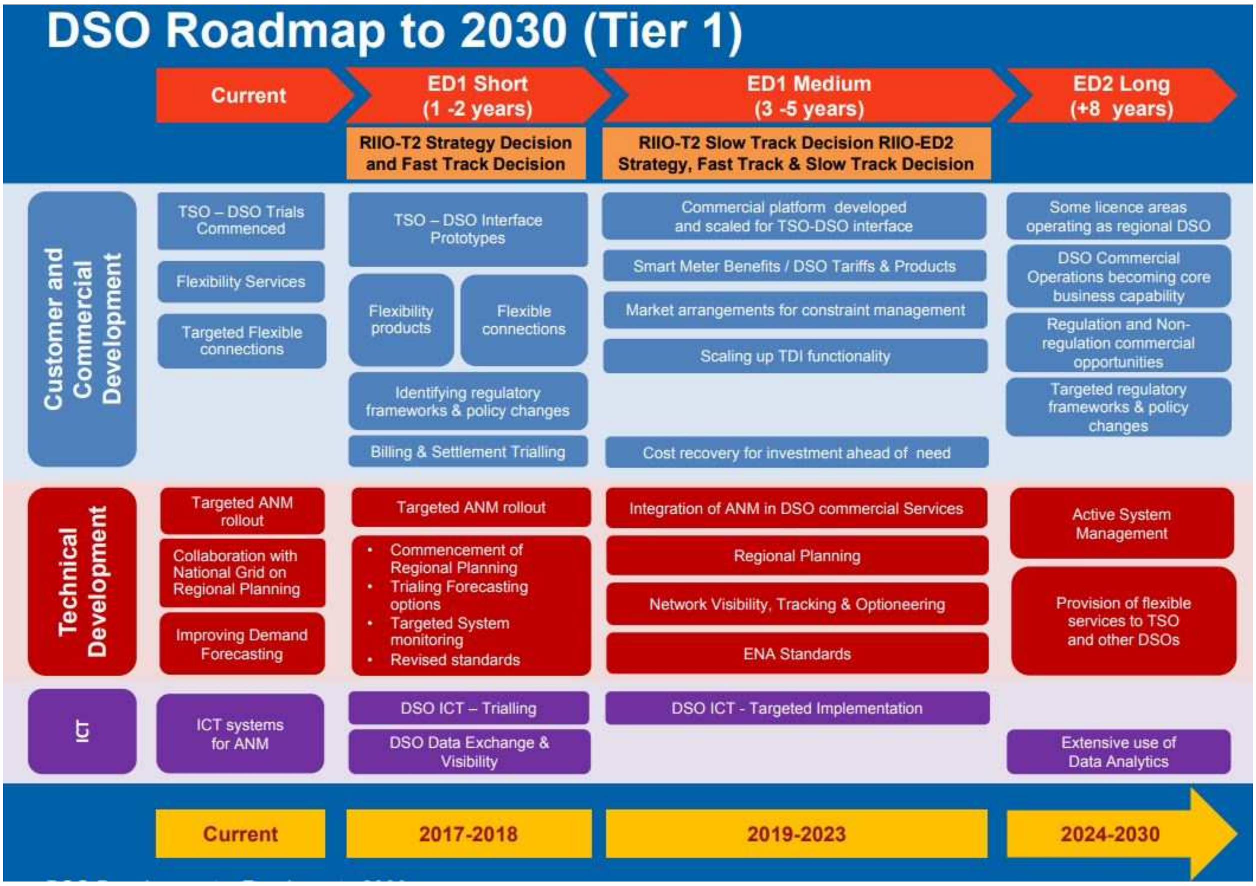
4. DSO coordinates – procuring for the needs of SO and DSO	Option 4 appears to be the most complex model to implement as it would entail the DSOs managing the entire GB network, which they currently have no visibility of. Systems would need to be put in place to ensure smooth transactions between the DSOs and the SO, but the DSOs should be in a better position to understand their own areas needs and constraints and this model would achieve granularity at the local level.
5. Joint procurement and / or dispatch – possibly through the use of a third party	Option 5 is also complex and potentially more difficult for small DER providers to understand and participate in. However, Option 5 would appear to be the most innovative and effective model longer term once the operating platform between the DSO and SO is established as this model should best enable local assets to access multiple markets.
6. Parallel DER routes to market – DSO-led approach alongside DERs and aggregators offering services directly to SO. Includes DSO acting as a commercial aggregator	Option 6 could be more burdensome for DER providers, with potentially conflicting contract offers. Option 6 would not enable broader procurement synergies to be realised at the D & T levels where the SO procures directly from DER or via independent aggregators. The aspect of DSOs acting as commercial aggregators though raises concerns relating to market fairness and letting the market decide.

The ENA also produced a 'DSO Roadmap to 2030' under Workstream 3 in 2017 (ENA, 2017a) which sets out the expectations on what can be delivered by the DNOs by the end of ED-1 (2023) and then by almost the end of ED-2 (which is currently due to end in 2031[6]). As can be seen in Figure 4 the ENA expect **some** network areas to be operating as regional DSOs at some point during the ED-2 time frame. This fits with WPDs ambitions to be 'market ready' by 2023 and operating as a DSO from the start of ED-2. However the ENAs expectation is that not all DNOs will have made the transition to DSO status until the end of ED-2[7]. This delay could have a serious effect on the rollout of local energy markets across GB in the next ten years and could potentially cause a bias in favour of the TSO continuing to co-ordinate balancing services.

[6] ED-2 could be reduced to five years instead of eight in light of March 2018 consultation on RIIO-2

[7] Interview with networks expert on 01/11/17

Figure 4 The ENA's DSO Roadmap to 2030



Source: Energy Networks Association website: http://www.energynetworks.org

However, the Roadmap is iterative and changes could be made within the next few years, including changes to what the future role of the DSO (if any) should be within the energy system. This could take account of recommendations made in Dieter Helm's 'Cost of Energy Review' (Helm, 2017) which advocated Regional System Operators or indeed a completely new model. In this respect WPD have signaled that they will be 'market ready' by 2023 with the expectation that future roles and relationships will have been determined by that point. The ENA recognise that any future arrangements would need to be compatible with the directions of BEIS and Ofgem and also with relevant European legislation in the Winter Package (European Commission, 2016b). In addition, system coordination between transmission and distribution would need to be incorporated into the emerging Project TERRE (discussed in Section 3.4).

Finally, there is concern over whether the Open Networks project will be able to produce any tangible outcomes,[8] as follows:

- The project is being led by the ENA but it is for BEIS & Ofgem to set the regulatory direction - although Government can be guided towards an end result they are not required to implement it and could indeed seek an alternative model.
- There will inevitably be conflict between the newly standalone SO and DNO/DSOs whilst they carve out their new roles and responsibilities and seek to protect their own interests.
- Not all the DNOs wish to transform into DSOs – due to both network concerns and shareholder priorities. As all DNOs are represented on the project could this influence the outcomes / decisions made?
- Would those outcomes have been different if the Project included more industry representation or had been led by a neutral third party?

RIIO

The current price control for electricity networks, RIIO-ED1, runs for 8 years from 2015-2023. Each DNO is allowed a 'base revenue' after a business plan and its costs are agreed. The base revenue is the amount of money the DNO is allowed to spend, and recoup from customers, to meet the agreed outputs of the Business Plan (Poulter, 2017). The revenue is mainly recovered from the electricity suppliers who use the networks to distribute energy to their customers. Revenue is collected through the application of Distribution Use of System (DUoS) tariffs. These charges are then recovered from end users as part of their total energy bill (see Section 5 which should be read in light of the RIIO framework for setting revenues).

A key intent of RIIO was the incorporation of innovation into network operations. The main driver for this was the move away from a Regulatory Asset Value (RAV) based on capex / opex with the creation of a single total expenditure category (totex) (Lockwood, 2014). Under ED-1 instead of additions to the RAV being made on the basis of actual capex they are now deemed to be 70% of allowed totex.

This move to totex should incentivise DNOs to identify the cheapest network solutions regardless of the opex / capex make-up (ibid). This change should greatly benefit local generators /DSR providers (such as the Cornwall LEM participants) where they can demonstrate that local flexibility services offer a cheaper NWA solution to the DNO in overcoming local constraints, rather than the DNO being incentivised towards a capex solution such as building a bigger network.

Innovation also became directly funded in RIIO through the Network Innovation Allowance (NIA) and the Network Innovation Competition (NIC). Together these two schemes fund DNOs to conduct research and run network-related trial projects for transitioning to a low carbon economy. NIA is awarded on a use-it-or-lose-it basis based as a percentage of base revenue to fund smaller research, development and demonstration projects; whereas NIC is awarded as part of an annual competition for large-scale projects (Poulter, 2017).

[8] Interview with networks expert 1 on 03/10/17

One of the criticisms of the innovation funding regime is that very few projects delivered have actually been rolled out as business-as-usual (BAU) (Poulter et al., 2017). However, by including innovation as an output rather than a separate pot this could encourage DNOs to implement innovative solutions more widely (ibid).

WPD have recently been awarded NIC funding of £2.9M for the Electricity Flexibility and Forecasting System (EFFS) which will build and test new network software to improve network load forecasting and identify opportunities for the buying and selling of flexibility services (Ofgem, 2017f). This is the software that will inform WPDs bids on the Cornwall LEM and should become BAU across the DNOs after the trial period if proven successful.

PRICE REVIEW (RIIO-2)

Reviewing the current price controls, Ofgem concluded that there are many positive aspects to RIIO, such as the focus on delivering outputs for consumers, and supporting innovation and incentives to encourage companies to plan for the long term. However, noting that the majority of network companies are delivering strong earnings towards the top end of its expectations in each sector, Ofgem signalled that companies need to prepare themselves for tougher price controls from 2021 (RIIO-2) (Ofgem, 2017i).

Ofgem's Senior Partner for Networks, Jonathan Brearley, also confirmed on 1 November 2017 (Brearley, 2017) that there are still questions for Ofgem to resolve around:

- The timing and length of price controls - is 8 years an appropriate timescale?
- How to achieve fair returns
- Business Plans – should they be fast tracked? How best should costs be assessed?
- Innovation – how should this be simplified and mainstreamed (so it's not just an add-on).

The University of Exeter's Energy Policy Group (EPG) submitted a response to Ofgem which questioned whether the length of price controls is appropriate (they consider eight years to be too long) and whether timeframes should be aligned with those for transmission (i.e. 2021 not 2023) (Poulter et al., 2017). The counter argument to this though is that eight years gives DNOs a long enough timeframe to plan and implement new projects with more certainty. And whilst from a policy perspective it might make sense to align with transmission, there is no real advantage to the monies aligning[9].

The EPG also stated that more needs to be done to enable flexibility and to deliver innovation projects which bring about a real change in practices, not just BAU (ibid).

Ofgem released a RIIO-2 Framework Consultation document in March 2018 (Ofgem, 2018b) which proposes that the length of the price controls are reduced to five years but that highlights that there are more disadvantages to aligning the timescales than to keeping them separate, with perhaps the main disadvantage being the enormous workload constraint for the industry given the size of the electricity distribution price control compared to the other price controls.

[9] Interview with networks expert 3 on 16/01/18

Ofgem also proposed potential new mechanisms to ensure fair returns, including a hard cap and floor to restrict returns from rising or falling below a pre-determined level. They also agreed that innovation should be more of an integral part of the process with outputs which become the new BAU. One proposal for achieving this is to extend funding out to third party competition where it is believed that new market-based models could provide better value for consumers and facilitate whole system solutions.

REGULATORY AND MARKET BARRIERS TO LEMS

There are several barriers to local energy markets as shown in Table 4, not least being the issue that there are many factors yet to be determined, as is the timescale for transition.

This uncertainty for the DNO/DSO also provides uncertainty for the LEM, particularly in relation to what services the DSO will be procuring from the market and what they will be managing themselves as the operator. Clarification is therefore needed regarding DSO activities to ensure a competitive marketplace. In this respect BEIS have already stated that DSOs shouldn't own storage facilities as that would be uncompetitive (BEIS and Ofgem, 2017a). However, through current DNO implementation of active network management (ANM) - which is intended to be implemented across all WPDs networks – the DNO/DSO are able to curtail generation themselves, rather than procure market solutions for flexibility. This undermines the value in market-based flexibility services, and leads to uncertainty for generators both in terms of operability and finance.

In WPD's DSO Strategy document (WPD, 2017a) they set out a range of operations that can be utilised by the DSO to manage system flexibility themselves (Automated Load Transfer; Dynamic Asset Rating; Voltage Reduction; ANM; Intertrip Connections; Timed Connections and Export / Import Limited Connections). Although these are recognised system management tools, the extent to which these tools are deployed will have the potential to limit the availability of market solutions provided by the LEM in overcoming constraints.

Currently DNOs are able to earn up to 1% of revenue from de minimis reward services. Under this arrangement Electricity North West are aiming to bid Project CLASS (Customer Load Active System Services) into the ancillary services market. CLASS was originally a Low Carbon Network Funded project to manage peak electricity demand through frequency response and voltage control (Cox, 2017) but due to its success this has now become a revenue stream for the DNO (albeit they are likely to reach their 1% revenue limit fairly on in the trial and there are caveats in place by Ofgem)[10]. However this concept undermines market competition and raises many questions on the extent and control of DSOs in the market place.

The barriers listed in Table 4 below are mostly in relation to WPD as the Cornwall LEM will be operating within this network area, and all references are taken from WPDs 'DSO Transition Strategy' published in December 2017 (WPD, 2017a) after consultation was held earlier that year.

[10] Electricity North West obtained a derogation from Ofgem to trial the trading of this service to the TSO

Table 4 Network Barriers to LEMS

Theme	Barrier	Possible Solution
Timescale for transition & willingness of DNOs for change	There is no set timescale for DNOs to transition to becoming DSOs. Not all DNOs appear to want to change or feel the need to change their operations.	WPD are actively working towards transition to DSO status. WPD have committed to establishing their DSO role by the end of ED-1 (2023) but this is not the case for all DNOs. And indeed, WPDs position is to be 'market ready' by 2023, anticipating that most of the DSO functions will come online during RIIO-2 (2023-2031). WPD will undertake an over-arching 'DSO Transition Programme' to lead this work. BEIS / Ofgem should set a timescale for all DNOs to commit to.
Coordination with TSO	Ambiguities as set out in the Open Networks Project about who should lead and coordinate on procurement of balancing services in future as distributed generation grows.	WPD would prefer to move to one of the DSO-led models identified in the Open Networks Project (see Table 4), presumably Option 4 or 6 as they claim the DSO-led models 'will result in the most efficient whole system outcome'. Either of those options should be beneficial to LEMs as these both have a wide role for the operation of DER. There may be market conflicts though in Option 6 with the role of the DSO as a commercial aggregator, which need to be assessed. WPD recognise that data sharing with the TSO will be critical to optimising the network.
DSO visibility of the network	DNOs currently only have limited visibility down to 33kV asset level with no visibility below this. They also have no real understanding of the amount of DER operational on the network at the street / household level.	WPD have signaled that they will primarily deploy supporting infrastructure on the EHV network down to the 33kV asset level before increasing visibility at LV levels. UoE have responded to WPD that they don't agree with this stance as DER and DSR will continue to develop across all levels of the network. Even if it is not realistic to upgrade the whole network at the moment then it would make sense to take one part of the network (like Cornwall with current high constraints) and upgrade the visibility and control across all voltage levels early on in the DSO process to provide some vital learning for later stages of the transformation (Bray *et al.*, 2017).

Balancing / Forecasting	Enhanced sensing with active technical and commercial mechanisms is required.	WPD will develop a platform (Project EFFS) to provide visibility, warn of critical peak price periods and take offers of flexibility services.
Market services	There is uncertainty over how many services the DSOs will be procuring from distribution markets and how many services they can operate themselves.	WPD have indicated that these are likely to be reserve services for real power and voltage control (such as Flexible Power) rather than fast acting products such as frequency response. WPD have signaled that secondary trading markets such as the P2P market may be created for DER providers. WPD have stated that they will use a mixture of tenders and market based arrangements for procurement of services. However, there is still uncertainty over how much flexibility WPD will procure at this stage.
NWA	DSOs should be encouraged to seek NWAs where this can be achieved at lower cost than reinforcement. RIIO helps in this effect, with a shift to RAV from totex rather than capex.	More acknowledgement needed of the value of network savings that could be achieved through deferment of network upgrades and potential recompense to those providing these NWA solutions. WPD have signaled that they **will** seek NWA from DSR and flexibility providers where issues can be solved for a lower total cost than reinforcing the network. Decisions will be taken in 'investment decision timescales' to reduce, defer or negate conventional build. These timescales will presumably correspond to RIIO timescales. DNOs should include in their Business Plans how they will include NWAs and the types of suitable projects which will be considered along with timescales for implementation.
Connections	Alternative connections such as ANM, Timed, Soft-Intertrip and Export Limited in CMZ are enabling more connections to be made to the network, but these come with penalties (such as LIFO) which undermine the operational capacity and financial viability of DER.	One solution used by DNOs is active network management (ANM) in Constraint Managed Zones (CMZ) which allows a new generator to connect within the zone for a quicker connection with a lower connection fee, in exchange for the DNO being able to curtail generation at times of system stress. This is a financially competitive solution for the DNOs as they still receive a connection fee and they can avoid network reinforcement costs by curtailing generation instead of upgrading the network. However, it incurs financial risk and uncertainty to the generator as the

	WPD are extending these products to all WPD areas and will include demand and storage connections.	DNOs can curtail generation themselves, rather than procure market solutions for flexibility, thus undermining the value in market-based flexibility services. Curtailment also often means that it is the renewable generation which is turned off first in the LIFO queue, undermining national targets and causing higher power prices. Therefore ANM is not a good long-term solution to achieving a smart and flexible energy market at the distribution level. The issue of connections is being raised through the Charging Futures work (see Section 5) which could either have a positive or negative effect on future connection arrangements depending on the model chosen. In addition, WPD have committed to creating a localised visibility platform (which will be publicly available) to demonstrate where there is congestion / capacity on the network.
Stacking of services	Stacking of revenues needed across DSO services and ancillary services to ensure viability.	WPD have signaled that they will be open to stacking of services in order to allow customers to participate in transmission and distribution level markets.
RIIO	RIIO still gives network operators the ability to 'game' the system in setting their revenues and innovation projects have to date been seen as add-ons rather than BAU.	The move to totex is welcomed but innovative solutions need to be seen as business as usual, not interesting add-ons with no long-term benefits to customers. RIIO-2 should therefore provide price controls which encourage active participation in the DSO transition and seek flexible solutions to network management. Clarification needs to be made as to whether the DSO transition costs will come out of RIIO-2 revenues (and therefore paid for by customers through network charging) or whether there should be a separate pot to fund this. The way in which the networks set their revenues has a huge implication on network charging as discussed in Section 5 which will have an impact on consumer behaviour.

Network Charges	WPD acknowledge that stronger locational signals for distribution network charges will have an effect on the siting of additional DER providers.	Network charges are currently being reviewed through the Charging Futures work being undertaken by Ofgem (see Section 5).
Storage	Ambiguities over whether DNOS should own / operate storage – which would be uncompetitive to flexibility providers.	Ofgem signaled that DNOs shouldn't own / operate storage as it is uncompetitive to the market. UKPN and Northern Powergrid however have argued against this. WPDs position is that storage owned / operated by DNOs should only be used as a 'last resort' if the market fails to deliver.

Source: (WPD, 2017b)

SECTION SUMMARY

As more power is connected at the distribution level this will have a major impact on the current and future roles of the TSO and the DNOs (WPD, 2017b), with the DNOs potentially becoming major operators in procurement of services and system balancing in future (Nolan, 2015) rather than the TSO as happens currently.

The TSO and the DNOs are therefore in the process of realigning their core businesses to better engage with this more distributed energy future. This is a positive step, but it will entail a period of uncertainty whilst their new roles and responsibilities are established. Therefore, communication between the system operators will be essential to outline rights and responsibilities of all actors involved in maintaining system balance (Ramos *et al.*, 2016). To this effect the ENAs work on the Open Networks Project will prove invaluable, not least because it brings all system operators together under one forum to discuss the issues involved.

However, BEIS are under no obligation to implement the outcomes from the Open Networks Project and could wish to implement a completely different model, such as that advocated by Dieter Helm. And whilst BEIS is currently stating that it wants a smart and flexible energy system (BEIS and Ofgem, 2017a), it is not stating how it wants that to happen and by when (Bray *et al.*, 2017). Instead it seems to be leaving these difficult decisions to be determined by the actors themselves.

The coordination scheme which is eventually chosen will not only determine the responsibilities of the system operators towards each other but will also determine their responsibilities towards third parties (i.e. suppliers, aggregators, DER providers etc.) (Hancher and Winters, 2017). The new roles, and the new services that will be procured by system operators, therefore will have a major impact on the scale, role and viability of local energy markets and so it should be questioned whether the ENA is the correct body to be leading on this scheme. Much can be learnt through 'trying by doing' and industry have a role to play here as well as the network operators in shaping future outcomes.

RIIO has been helpful in the move from capex to totex in defining the asset value of networks. RIIO-2 should go further though in incentivising DNOs to complete their DSO transitions and to seek cheaper market solutions to network capacity issues. There is a need for networks to engage fully in this process and to actively seek to support flexibility markets within their network areas.

WPD are forging ahead with their ambition to be market ready by 2023. This is welcomed but there is still much to be determined, learnt and overcome within the next few years.

5. CHANGES TO NETWORK CHARGES AND ACCESS RIGHTS

SECTION OVERVIEW

At present all users of the GB electricity networks pay to use them in some way. Generators use the networks to transport their electricity to where it is needed whilst demand users use the networks to consume electricity when they need it.

However, Ofgem are now considering whether the current system of network charging is still appropriate and 'fair' to all users given higher volumes of generation connected at the distribution level; behind the meter technologies and opportunities for prosumers to reduce their network usage (thus their network charges) whilst still having the reliability of the networks available at all times.

Ofgem are also looking at connection and access rights as part of these reviews, which are all bannered under the 'Charging Futures Forum' work.

Several proposals have been put forward by Ofgem regarding a way forward, but these haven't been subject to impact assessment at this stage. The models identified have varying incentives / disincentives for DER and flexibility providers as well as prosumers.

CURRENT CHARGING REGIME

Users of the networks pay for use of the distribution and transmission networks through four charges:

- Connection charge
- Transmission Network Use of System charge (TNUoS)
- Distribution Use of System charge (DUoS)
- Balancing Services Use of System charge (BSUoS)

Charges are calculated according to the charging methodology in two industry codes:

- TNUoS, BSUoS and transmission connection charging methodology can be found in the Connection and Use of System code (CUSC).
- DUoS and distribution connection charging methodology can be found in the Distribution Connection Use of System Agreement (DCUSA).

System charges include **'forward-looking'** charges and **'residual'** charges which are top-up charges set to ensure that total allowed revenues are recovered: -

- **Forward-looking charges** reflect current and forward-looking costs associated with generating or consuming energy. For some users these can vary by location on the network, or by time of use. These charges reflect the marginal cost of the networks in the long run (the cost of adding each additional unit of capacity on the networks)

- **Residual charges** don't cover specific things, but are broadly used to recover sunk or fixed costs. These costs don't vary with network usage, and largely relate to costs that have already been incurred, such as past investments. Residual charges represent around 80% of revenues at transmission level and around 50% at distribution level (CMS, 2017) and (Ofgem, 2017n). In addition, Balancing System Use of System (BSUoS) charges are currently a form of cost-recovery charge, so are similar to residual charges (Ofgem, 2017p).

RESIDUAL CHARGES

Ofgem launched a Targeted Charging Review - Significant Code Review in August 2017 (Ofgem, 2017p) to review the current charging regime of **residual charges** to ensure that all consumers who use the networks pay an appropriate share.

Ofgem explained that the current residual charging regime was designed for a system with passive demand and large-scale, centrally-dispatched power stations; while today's power systems are becoming more decentralised and responsive. The increased availability of smaller scale generation, private wire networks, and storage means that some consumers may more easily reduce net demand or peak net demand (by using generation and storage behind the meter). Therefore, users who don't have these technologies will bear a higher burden of the residual charges. This has been termed the 'death spiral' effect -as more customers go off grid, the network costs for those remaining will rise – increasing the incentive for others to leave as well (Lacey, 2014) (Nolan, 2015).

Ofgem then published a working paper on **residual charges** in November 2017 (Ofgem, 2017o). The document outlines seven different mechanisms for setting residual charges, but then discounts several of them as inappropriate; leaving proposals for fixed charges (per user), ex-ante capacity demand, ex-post capacity demand and gross consumption charges (business customers only). Of these the only ones which would reward prosumers for their actions are the ex-ante and ex-post capacity demand charges as shown in Table 5.

Ofgem will be conducting a draft impact assessment on the proposed charging arrangements in early 2018 with the findings due to be published in the second quarter of 2018. But BEIS / Ofgem need to consider what type of customer behaviour they are wanting to incentivise / disincentivise through adopting any new methodology.

Table 5 Residual Charging Mechanism Proposals

Option / Mechanism	Carried Forward	Thoughts
Net at meter volumetric charges	No	Current system – discounted by Ofgem as the way forward as likely to result in inefficient network use. Concerns are that customers with BTM technologies can have the back-up reliability of the network but pay little towards overall network costs.
Fixed demand charge (per user)	Yes	This would be a fixed charge per user based on different user profile classes. This option is the simplest proposal to be carried forward but is likely to be viewed as 'unfair' from a prosumer view as it doesn't relate to actual access of the network and could lead to more prosumers disconnecting from the network. Fixed charges provide more revenue certainty for networks, but can lead to overcharging of all consumers and does nothing to incentivise consumer behaviour.

Ex-ante capacity demand charges	Yes	Charge would be based on a user's agreed or connected capacity, with possibly an initial 'capacity block' charge at a lower rate with any additional capacity charged at a higher rate. This could lead to more efficient network planning as capacity requirements would be known in advance, and would disincentivise customers from exceeding their capacity limit. However, this could be unfair to heat pump and EV customers who have chosen electric over fossil fuel alternatives but who will therefore have a higher usage.
Ex-post capacity demand charges	Yes	This would be based on peak use, charged based on *user's own* highest usage half-hours over a defined period (not on system peaks). This mechanism would incentivise consumer behaviour in the same way as triad avoidance.
Gross volumetric consumption charges	Partially	Ofgem have discounted this as a route for domestic customers, but are analysing the option for business customers.
Net volumetric import ***and*** export charges	No	Ofgem have discounted this option as they propose that residual costs should be on final demand, not on generation (export) but state that this may be more appropriate for forward-looking charges.
Max peak import ***or*** export capacity charges	No	This option would charge users for the maximum import or export capacity requirement. Ofgem have discounted this option as they propose that residual costs should be on final demand, not on generation (export) and because it would disincentivise prosumers to have any export capacity.

Source: (Ofgem, 2017o)

EMBEDDED BENEFITS

Ofgem also believe that the current network charging regime has distorted the playing field between generation that connects to the transmission network and generation that connects to the distribution network - with distribution level generation given a competitive advantage (Ofgem, 2017m p.52). As a result, Ofgem also took the decision to cut the amount of embedded benefits paid to DER providers through two changes to the CUSC, Modification Proposals CMP264 and 265.

Embedded benefits (EB) are payments that are made to generators attached to the distribution network, as opposed to the transmission network, so called because these generators are 'embedded' further down the system closer to sources of electricity demand. EB are based on the contribution made by embedded generators to reducing demands on the transmission network, especially during the three half-hours with highest demand in the year (the Triad).

Ofgem approved a large cut in the residual element of EB as part of the Significant Code Review on residual charging, effectively taking EB from a current value of £47.30 per kW of capacity to less than £2 per kW over a three-year phase-in period from April 2018. Ofgem faced a judicial review on this decision in January 2018, which was brought jointly by eight small generating companies, which Ofgem successfully overcame.

Cornwall Insights remarked that 'this is one of the worst decisions we have seen from the regulator' and went on to explain that in their view Ofgem had underestimated the impact of this change on the economic viability of certain embedded units in its modelling assessment at the risk of triggering capital flight from certain parts of this market (Cornwall, 2017).

The decision to uphold CUSC Modification Proposals 264 and 265 provides a strong incentive to invest in DSR, at the expense of local generation, or alternatively to site generation behind the meter – albeit even BTM is under threat from the TCR.

FORWARD-LOOKING CHARGES AND ACCESS RIGHTS

During the TCR process it was argued that Ofgem should review the whole of network charging holistically instead of reviewing residual charges in isolation. This led to Ofgem publishing a working paper on ***forward-looking charges*** and ***access rights*** in November 2017 (Ofgem, 2017k). Whilst it makes sense to look at network charges as a whole, these two consultations are still being developed separately (albeit under a joint Charging Futures Forum banner), which makes the overall assumption that there will still be a split between forward looking charges and residual charges rather than adopting a new, more holistic approach.

The '*Reform of electricity network access and forward-looking charges*' paper (Ofgem, 2017k) looks at future access rights to network connections and considers how to make more choice in gaining access rights, rather than relying on a first come first served basis which can lead to long queues in gaining connections – options include being able to buy access for a specified length of time, or the right to be able to trade only within a specified local area, or being able to trade connection agreements between parties. Another option is to introduce auctions for access rights.

There are almost no examples given within the document of these differing scenarios and it is very unclear what the individual proposals would constitute and what their implications would be. It will therefore be imperative to keep track on progression throughout 2018 and to provide Ofgem with consideration as to how local arrangements like the LEM can help to overcome network constraints within a geographical area by optimising trading to overcome traditional barriers. Ofgem have also discounted the option of Locational Marginal Pricing in the review which could also aid in optimising trading to overcome network constraints (see Section 6.6).

LESSONS FROM AUSTRALIA

How to develop and pay for networks in an energy world of increasing proportions of onsite electricity generation has already become a central challenge in Australia. However their approach to dealing with this challenge has been markedly different to Ofgem's.

A report from the Massachusetts Institute of Technology (MIT, 2016) highlighted the possibility and consequences of 'grid defection', caused either by physical conditions such as the ability to install embedded generation within a residence or business, or by economic considerations such as the desire to avoid network costs:

> Regulators and policy-makers must carefully monitor for conditions that could lead to a serious threat of inefficient grid defection. If these conditions arise, regulators and policymakers must reconsider the costs that are included in the tariff as well as other measures to prevent substantial cross-subsidization among consumers and a potential massive grid defection with unforeseen consequences (MIT, 2016).

This is the 'death spiral' effect mentioned above. The Australian Energy Market Commission (AEMC) recognised the need for adjustments to network tariffs due to the high risk of grid defection (AEMC, 2016a) which was followed by changes to the National Electricity Rules. The AEMC embraced the need for the energy market to 'evolve' and devised key enablers to incentivise the uptake of DER within the distribution network (AEMC, 2016b) including:

- Cost-reflective distribution network tariffs: developing prices that better reflect the costs of network services
- Network support payments: embedded generators are eligible for payments from networks in recognition of the benefits provided by delaying or avoiding investment in the network
- Regulatory investment tests for distribution/transmission: require networks to consider the costs and benefits of all credible network and non-network solutions
- Distribution network planning and expansion framework: annually plan and report on activities that are expected to have a material impact on the network in a distribution annual planning report, and to publish a demand-side engagement strategy
- The capital expenditure sharing scheme and the efficiency benefit sharing scheme
- The demand management incentive scheme and allowance to provide incentives and funding to invest in non-network solutions

The AEMC consider the implementation of these network pricing reforms to be 'the essential foundation to support energy market transformation' (AEMC, 2018) and are conducting annual reviews as of 2017 into the effectiveness of the policy (2017 review information not available until March 2018).

The difference to the GB approach to reviewing network charging is vast. Whilst the AEMC embraced the need for the market to evolve and actively sought to incentivise the uptake of DER, Ofgem have taken a far more precautionary approach; treating the issue of network charges as a self-contained issue without, apparently, considering the wider consequences on the energy market.

SECTION SUMMARY

The Charging Futures Forum consultations are still ongoing, and so no final verdict on its effectiveness can be drawn at this stage. However, there is much cause for concern.

Ofgem have said that they are taking an 'agnostic' approach to network charges, believing that the cost of the network is separate from 'policy aims'[11] but this can be seen as a short sighted approach which has the potential to harm the ambitions of the Smart Systems and Flexibility Plan (discussed in Section 6) and the Clean Growth Strategy (BEIS, 2017) through limiting the uptake of DER.

Ofgem's decision to maintain the separation between future costs and residual costs from the beginning is also disappointing. Network charging is a complex, iterative and dynamic process which is all the more important at this time of energy technology, system operation and economic change and as such, maintaining the 'old' two-tier system of network charging, while so much else changes, is a wasted opportunity to create a system which rewards customers for their behaviour change, such as has been created in Australia.

Whatever system of network charging is finally decided upon will have a large impact on the way in which network operators recover their income and as such should be fully thought through and costed before the next round of RIIO funding is finalised.

Table 6 Changes to Network Charging

Barrier	Possible Solution
Targeted Charging Review – residual charges Any changes to the existing charging regime will have a potential impact on how prosumers will use the network in future. Whilst it may be sensible to make these customers pay a fair charge for their ability to rely on the network this should be done in a way which still incentivises prosumers for their positive actions.	BEIS / Ofgem need to need to consider what type of customer behaviour they are wanting to incentivise / disincentivise through adopting any new methodology. Currently only the ex-ante and ex-post capacity demand charges option reward prosumers for their behaviour. Keep a watching brief on developments on this in 2018 and engage in consultation events.
Forward looking charges and access rights Details are very sketchy at the moment but could have widespread implications for connections	Keep a watching brief on developments on this in 2018 and engage in consultation events.
Embedded Benefits – the slashing of EB will have a major negative effect on the revenue of small scale generators	This retrograde decision has already been made and will implemented from April 2018, despite Ofgem facing a judicial review in January 2018.

[11] Advice from a Charging Futures Panel member

Part 2 POSSIBLE MARKET CHANGES

6. OPENING UP NEW FLEXIBILITY MARKETS

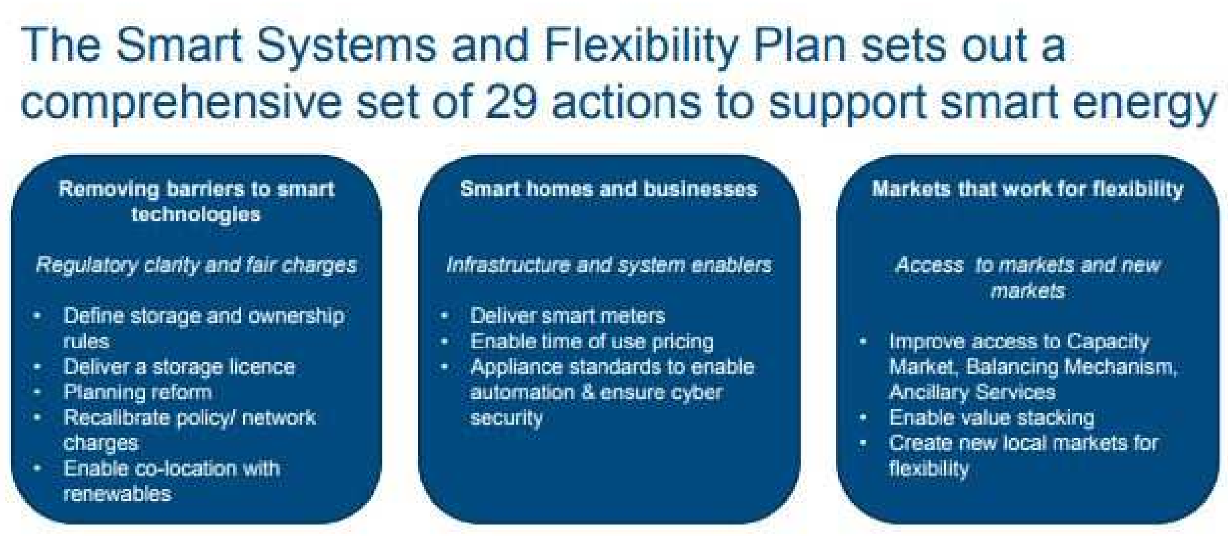
SECTION OVERVIEW

Since privatisation at the end of the 1980s the GB electricity system has been a large, centralised system dominated by incumbents (Mitchell, 2014) with power flowing one-way from centralised generation through the transmission and distribution networks through to end consumers. However, this traditional system, is now in the midst of transformation to a much more decentralised system with two-way power flows from distributed energy resources (DER) and renewable technologies (Ramos *et al.*, 2016).

As system flexibility will be the key enabler in delivering this transformation (Shakoor *et al.*, 2017) Government need to ensure that flexibility markets are made more accessible for small energy providers, by removing regulatory barriers, and ensuring value for flexibility.

BEIS has recognised the importance of flexibility in the electricity system and following on from their Call for Evidence (CfE) in late 2016 (BEIS and Ofgem, 2016), BEIS and Ofgem published the Smart Systems and Flexibility Plan in July 2017 (BEIS and Ofgem, 2017a). The plan identified 29 actions for removing regulatory barriers to existing markets and opening up new flexibility markets, as summarised in Figure 5. Most of these actions are identified in this section, whilst the remaining actions (regarding access to existing markets) have already been discussed in Section 3.

Figure 5 The Smart Systems and Flexibility Plan Actions



Source: (BEIS and Ofgem, 2017a)

The main technologies for unlocking flexibility at the local level will be the implementation of demand side response (DSR) and energy storage utilised in conjunction with DER; as well as developments in smart metering, IT platforms and data sharing. Their establishment is vital to the development of new local flexibility markets, such as the LEM and enable more DER providers to connect to the network.

6.1 THE ROLE OF SMART METERS

The rollout of smart meters to domestic properties and smaller businesses could provide a platform for energy system transformation (Connor *et al.*, 2014) and will be an essential requirement for LEM customers in being able to trade their electricity, as smart meters are crucial for the accurate measurement of consumption patterns (Vallés *et al.*, 2016) and for setting a baseline between the buyer and the seller in order to establish a proper valuation of transactions (Good *et al.*, 2017).

The EU's Smart Meter Rollout Directive (2009/72/EC) mandates that all member states should achieve at least an 80% rollout of smart metering by 2020. The UKs smart meter rollout programme should bring the UK into compliance with this directive (Warren, 2014) and (Connor *et al.*, 2014), although there have been delays, ICT, communications and installation issues to date (Shakoor *et al.*, 2017) as shown in Table 7 which will cause an ongoing risk to the wider establishment of LEMs until they have been resolved.

Table 7 Issues with Smart Meter Rollout Programme

Programme delays – the delay in rollout has reduced the economic benefits by over £1,013 million in comparison to the expectations made in 2014
Lack of interoperability of first generation SMETS1 meters – causing a risk of stranded assets and negative impact on customer engagement
Cost of installation – between 10-15% of properties may require more than one visit, potentially pushing up the cost by £1 billion
Communications issues – with SMETS2 meters, prepay meters and meters in multiple occupancy dwellings is having a knock-on effect with their deployment
Cost burden to suppliers of the roll-out programme – is potentially squeezing resources for innovation products such as ToU tariffs and integrated home services

Source:(Shakoor *et al.*, 2017)

Other benefits of smart meters include the utilisation of 'smart' automated appliances, many new tariffs, including Time of Use Tariffs and Real Time Pricing, and half hourly settlement. Since April 2017, all medium and large businesses must be settled on their half-hourly electricity use under code modification P272; and from July 2017, suppliers ***who want to***, are able to settle their small business and domestic consumers using half-hourly data. However, in July 2017 Ofgem published their launch statement on the Electricity Settlement Reform Significant Code Review which seeks to introduce ***mandatory*** half-hourly settlement (HHS) for domestic and smaller non-domestic customers (Ofgem, 2017j). HHS will be a key enabler for these customers to engage in flexibility markets such as the LEM.

6.2 THE ROLE OF DEMAND SIDE RESPONSE

OVERVIEW

Demand side response (DSR) could involve LEM customers (commercial and domestic) increasing, decreasing, or shifting the time of their electricity usage in response to a signal. This could be to aid balancing of the local network, or to overcome a particular network constraint or to provide ancillary services to the System Operator or the DNO. In return for their flexibility, customers could receive financial incentives such as cheaper half-hourly tariffs or they could be paid directly for their actions (i.e. when participating in ancillary service markets). The large increase in flexibility requirements will result in significant growth of the overall value of such services in the future GB system (Shakoor *et al.*, 2017).

BENEFITS OF DSR

DSR can deliver value to the electricity system in a range of ways including: -

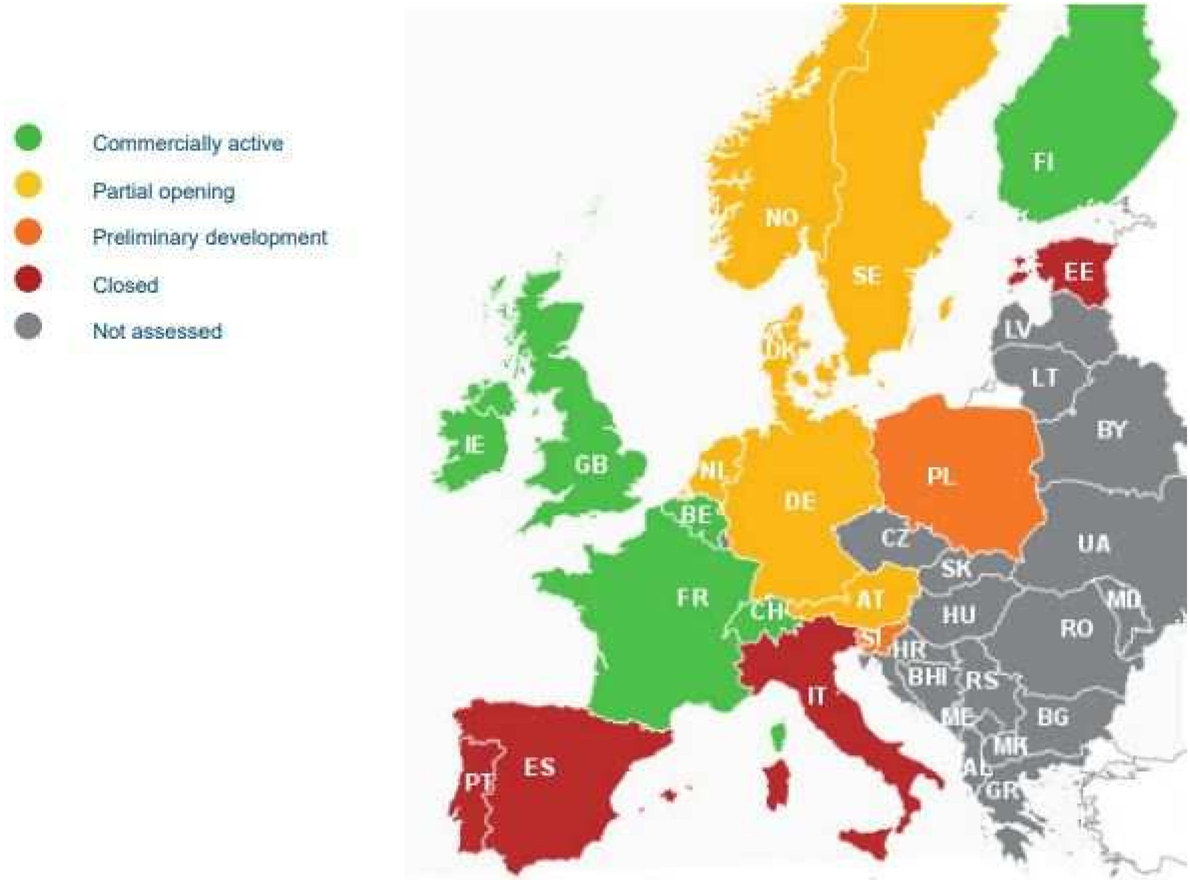
- **Operational network balancing** – DSR can allow demand to be turned up or turned down to help balance networks; helping avoid outages at times of system stress. Currently this occurs only on higher voltage networks but there is great potential for use at domestic level networks also.
- **Provision of capacity** – lowering demand can free up capacity for other areas of the network.
- **Benefits to networks** – can avoid the need for reinforcement of the network; support cheaper and quicker connections; contribute to avoided investment.
- **Supplier / consumer usage reduction at times of high prices** – enables consumers to receive lower bills
- **Maximise the use of DERs -** reducing the need for new peaking plant capacity and investment (PA Consulting Group, 2016).

There has been renewed interest in DSR globally as a result of climate change and energy security issues coming to the forefront of the political agenda (Warren, 2014). Many utilities in the US are obliged by regulatory or legislative requirements to consider DSR in their resource planning, while the Energy Efficiency Directive of the EU states that the planning process should consider the peak shaving effects of DSR (Paterakis, Erdinç and Catalão, 2017).

Making demand response happen is also an essential part of the European Union policy strategy reflected in The Third Energy Package (Vallés *et al.*, 2016). GB is moving ahead with integrating DSR into its ancillary services (see Section 3.2), but there are still questions to be addressed to facilitate wider participation in the electricity sector, which the EU 'Winter Energy Package' (European Commission, 2016b) is currently attempting to deal with. Questions include efficiency and competition to achieve the wider system benefits of DSR and industry requirements to remain compliant with the EU internal energy market (Edwards, 2017).

A study by the Smart Energy Demand Coalition mapped the ability of DSR to access markets across the European member states in 2014 and then updated this again in 2017 (as shown in Figure 6). They found that improvements had been made in almost all European countries, but that this had been gradual. They assessed that the launch of the Winter Package marked the start of the large-scale unlocking of DSR potential in Europe, with current DSR activity standing at around 20GW out of a potential value of 100GW, rising to 160GW in 2030 (SEDC, 2017).

Figure 6 Explicit DSR in Europe (2017)



Source: (SEDC, 2017)

REGULATORY AND MARKET BARRIERS

DSR in GB has to date been mainly provided by large scale industrial and commercial (I&C) companies only (CGI, 2017) due to these customers having access to metering requirements, HHS and smart tariffs which have enabled this. However a survey by Ofgem in 2016 (Ofgem, 2016) found that 71% of companies in the industrial, commercial and public sectors do not participate in DSR due to a number of barriers, including concern over business performance and a difficulty in understanding the products and channels available.

As shown in Table 1 GB Markets & Technologies in Section 3.1, DSR has been able to access the Capacity Market (CM) and several ancillary service markets to date, albeit the percentage share in these markets has been low. However given the expected changes to the ancillary services market (Section 3.2), the announcement that stacking will be allowed across these markets (BEIS and Ofgem, 2017a) and recognition of the role of independent aggregators (Section 6.3) this percentage share could rise in future.

Domestic and smaller non-domestic customers have to date had limited participation with DSR (due to the above metering arrangements not being in place to allow for their participation). However, with these improvements, DSR could become a future market for those customers as well.

Most of the discussion of DSR potential concentrates on 'active' demand-side participation but acknowledgment should also be made that not all domestic and small commercial consumers may want to actively participate, due to the potential time and commitment involved, and therefore may prefer to act 'passively' (Warren, 2014) and (Balta-ozkan *et al.*, 2014). Local energy markets should therefore ensure that involvement can be automated and as hassle-free as possible for these customers. Automated operation may prove more popular than approaches that require consumer involvement, even where the latter offers greater systemic benefits or is more economically efficient.

BEIS and Ofgem identified multiple barriers for customers in participating in DSR markets in the 'Smart Systems and Flexibility Plan' (BEIS and Ofgem, 2017a) as shown in Table 8. In addition, National Grid are facilitating Power Responsive to stimulate increased participation in DSR by 2020, which from 2018 onwards will include domestic and small non-domestic customers as well as I&C customers, which it has concentrated on to date. The TSO has an ambition to procure 30-50% of its balancing services by 2020 through demand side measures (BEIS and Ofgem, 2016), which to-date stands at just 6% (PA Consulting Group, 2016).

Table 8 Barriers to DSR

Barrier	Possible Solution
Access to ancillary services	Rationalisation of services to simplify process and align timescales for tendering. National Grid will also trial auctions from late 2018.
Restrictions on the ability to stack revenues from ancillary services alongside Capacity Market (CM)	Allow stacking of revenues between the CM and ancillary services. Review exclusivity clauses.
Access to Balancing Market	Provide for participation from independent aggregators.
Baselining & settlement	Clarify the role of aggregators in regard to relationship with suppliers / set a code of conduct. Should aggregators be balancing responsible parties i.e. exposed to imbalance pricing?
Aggregators can't change the portfolio of DSR participants which make up a CM unit. Therefore, if one participant withdraws the whole contract is nullified.	Enable asset reallocation by DSR providers.
Technical issues	Simplify metering requirements. Improve forward-looking signals for network usage to encourage price flexibility related DSR.

Structure of network charges	Being reviewed through the Embedded Benefits Review / TCR / forward looking charges review.
Limited awareness of DSR & financial benefits of DSR	Power Responsive project launched by National Grid to raise awareness and engage with businesses.
Limited access to DSR market for domestic and smaller non-domestic customers due mainly to smart meter rollout not being complete	Smart meter rollout should be complete by 2020.
Limited availability of smart tariffs, smart appliances	Half hourly settlement – introduce mandatory HHS for domestic and smaller non-domestic customers. Encourage smart tariffs. Set standards for smart appliances. Domestic energy storage. EV charge points & Vehicle to Grid technologies.
Cyber security	Study commissioned to assess magnitude of cyber security risk up to 2030.

Sources: (BEIS and Ofgem, 2016) and (BEIS and Ofgem, 2017a)

DER PLANNING

An essential step in transforming to a flexible local energy market and realising the potential of DSR is to encourage the building of distributed energy resources (DER) for both supply and demand (Mitchell, 2017).

The UK Government commissioned an international study in 2016 (Future Power System Architecture) which compared the GB energy system with a number of other countries facing similar system challenges (California, New York, Texas, Germany and Ireland). International experts consulted in the study expressed the need for greater system wide planning and found that the value that DERs can bring is being accepted internationally. Indeed, policies in all of the countries reviewed are aimed at promoting and encouraging the adoption of DERs (IET, 2016).

Through the Renewable Energy Planning Database BEIS track all renewable energy planning applications submitted (over 1MW) on a monthly basis to forecast trends in RES generation as part of monitoring progress against the UKs renewable energy targets (BEIS, 2018). Although this gives a national overview of installations to monitor uptake, it is limited by size and does not assign any value to how these installations can assist in network planning and operations.

IGov[12] have argued for some time that Ofgem should require DNOs to formulate DER Plans for each DNO area to enable all stakeholders to know what DER are available within the network (Mitchell,

[12] Innovation and Governance for a Sustainable Economy 2012-2016 and Innovation and Governance for Future Energy Systems 2012-2019, part of the Energy Policy Group at the University of Exeter

2017) and to consider these when network planning. This is already happening in New York and California as shown below. The value of a DER Plan is to: -

- Begin the process of moving towards a fuller integration of DER into DNOs network planning, operations and investment
- Determine optimal locations for the deployment of DER
- Support efficient DER deployment through market arrangements
- Remove barriers to DER deployment

  (adapted from CPUC, 2014)

The extent to which DER have been assessed and valued; the extent to which those DER values can be captured within markets and from system operation payments; and the degree to which non-wire alternatives (NWA) can be incorporated into system operation have major implications on how networks could be charged; how they could be regulated and the type of tariffs which would complement a DER system (Poulter, Mitchell and Hoggett, 2017) and (Mitchell, 2017).

Additionally, data, communications networks and information flows are increasingly being viewed as part of the energy system. As the energy market transition unfolds these are likely to become critical components of distribution system planning and facilitating integration of distributed energy resources. The task of converting data to information has been highlighted as a new capability required within the sector, and this is only likely to become more complex as more devices connect to and become part of the energy systems (IET, 2016).

DSR LESSONS FROM NEW YORK AND CALIFORNIA

Both New York State and California have instituted a regulated process to reveal their DER resource and value. In both cases, they have required distribution utilities to undertake distribution resource plans, and have given them a couple of years to complete them. In New York this is called a distribution system implementation plan (DSIP) and in California it is called a distribution resource plan (DRP). The process of developing them opens up access to data and involves all interested stakeholders (Mitchell, 2017).

However, even with policy support there are still perceived barriers to the implementation of DSR in these States which can provide insight to the emerging GB market (see Table 9). This table has been created by taking the issues identified in New York and California and then applying them to the GB market. Not all of the issues directly translate to the GB situation due to different market arrangements between the US and GB, but each issue can provide insight to the barriers which have been uncovered throughout this report; particularly regarding conflicts and co-ordination between the TSO and the DNOs, and the stacking of contracts between different market services.

Table 9 DSR Lessons from New York and California

Issue	Why is this an issue?	GB Lesson	Where Discussed in Report
Forecasting – Improving Forecasting Methodologies to Predict System Needs	Utilities[13] need to adequately forecast DER impacts as the prevalence of DER increase. Inclusion of energy efficiency and solar PV in load forecasts reveals that consumption is declining or growing more slowly than previously forecast. Stakeholders need to understand how investments in energy efficiency and local energy resources contribute to a more cost-effective grid over time.	DNOs need a methodology for anticipating the effect of intermittent generation on the networks (i.e. DER Plans). This will help inform decisions on future investments. Energy efficiency and impacts of DERs should also be taken into account when forecasting requirements for balancing, ancillary services and the Capacity Market. However, whilst energy efficiency and onsite generation will reduce overall load, this needs to be balanced against the anticipated rise in electricity needed for the electrification of heat and EVs.	4.2 3.2, 3.4 & 3.5
Local dispatchability	Conflicts between wholesale balancing, area and sub-area balancing.	Applicable to ENA Open Networks project on models for DER. Conflicts can arise when procuring / dispatching DSR at both SO and DNO level.	4.2
Lack of a coherent vision for DSR services	There are different and competing visions of DSR due to historical DSR being mainly utilised for peak shaving and emergency response only and anticipated future services around frequent availability and frequent dispatch. There is also no discussion around providing incentives and value to customers in participating in DSR.	Overarching DSR strategy / direction needed from BEIS / Ofgem. Link to SO work with Power Responsive.	3.2 & 6.2
Short advance notification	More value to DER if capable of dispatch within 30 mins, instead of day-ahead, but short notification for DER	Coordination needed between SO and DNO. Which market will be most lucrative to DER?	4.2

[13] Utility companies in NY currently include the distribution and supply arm of the electricity system

	requires more coordination with customers and shorter windows reduces the pool of eligible customers.	Some products / customers may be more suited to long-term markets (day / weeks in advance) rather than short-term markets (minutes in advance).	
Outages	If DSR providers have other commitments they are usually unable to help in times of outages. Yet, the inability to utilise a significant number of DER during an outage is identified as a failure of the resource.	Potential conflicts between ancillary services (such as frequency response) and other contracted commitments.	3.2 & 4.2
Lack of procurement target	Unlike storage which has a specific target to be met by a specific timescale, DSR has a 'soft' target going back to 2003 which has already been met. This has resulted in capacity remaining flat or declining in terms of growth as there is little encouragement to procure over other resources.	National Grid has a target to achieve 30-50% DSR in ancillary services by 2020 through the Power Responsive campaign. DNOs could also incorporate a target within their DSO strategies.	3.2
DSR is required to be cost effective relative to other resources	The things that are stated as future values for DSR: increased availability, frequent dispatch and short notification times, are not reflected as significant values in the cost effectiveness methodology.	DSR currently only offered 1-year contracts in the Capacity Market - would longer contracts ensure more market confidence? Stacking between the CM, ancillary services and DNO services should enable access to more revenues.	3.2, 3.5 & 4.2
DER Plans & Mapping	Greater emphasis on providing up-to-date information is needed considering the importance of this data for DG developers and other third-party DER providers.	DNOs should develop regular DER Plans with up-to-date information and use this information to inform their operational and investment decisions. DER Plans should then be made publicly available to inform DER providers of optimal locations and market arrangements for the deployment of DER.	4.2 & 6.2
Planning for Non-Wires Alternatives (NWAs)	As the energy grid becomes more dynamic and DER levels increase, some traditional projects may be deferred or cancelled by NWAs that may	More acknowledgement needed of the value of network savings that could be achieved through deferment of network	4.2

	be more cost-effective than utility solutions. Future DSIPs should provide updated assessments of the types of projects suitable for NWAs. They should also describe how utilities are making efforts to reduce the lead-time required for NWA implementation. The long lead-time should decrease as the process becomes more standardized and utilities are more familiar with implementing NWA projects.	upgrades and potential recompense to those providing these NWA solutions. At present, one solution used by DNOs is active network management (ANM) in Constraint Managed Zones (CMZ) which allows a new generator to connect within the zone for a quicker connection with a lower connection fee, in exchange for the DNO being able to curtail generation at times of system stress. This is a very competitive solution for the DNO as they still receive a connection fee AND they can avoid network reinforcement costs by curtailing generation instead of upgrading the network. This is financially beneficial to the DNO, but, it incurs financial risk and uncertainty to the generator as the DNOs are able to curtail generation instead of procuring market solutions for flexibility, thus undermining the value in market-based flexibility services. DNOs should include in their Business Plans (or future DER Plans) how they will include NWAs and the types of suitable projects which will be considered along with timescales for implementation.	
Data	A large obstacle to achieving a resilient, DER-integrated energy grid is how little data utilities can gather and share regarding the operation of the grid.	BEIS & Ofgem should provide regulatory clarity over data – in particular encourage data sharing between the SO, DNOs, suppliers and platforms such as the LEM at the greatest possible granularity. This can include data regarding network constraints and the availability of DER on the network. Also, decisions needed on availability of meter data. Data protection regulations, including European General Data Protection Regulation potentially make it difficult to access suitably granular meter data. ELEXON are working with Ofgem on potential approaches to meet the GDPR requirements as part of the Half Hourly Settlement design work (Elexon, 2017a).	4.1 & 4.2

EV Infrastructure	More detailed plans needed on how to engage in the development of the EV market, enable EV infrastructure deployment, and engage with customers.	Need to understand impacts on the network, demand and variation by locality. EV infrastructure has huge potential for delivering flexibility services in the future with V2G technologies.	4.2
Distributed System Platform Investment	The utilities need to invest in systems and technologies that provide information that enables new entrants to participate in a networked and responsive grid.	Integrated system platforms will be key to providing a local energy market / P2P trading / local balancing. Consider models put forward by the ENA Open Networks project.	4.2

Sources: (Greentech Leadership Group, 2014) (California Energy Commission, 2017) and (Acadia Center, 2017)

6.3 THE ROLE OF INDEPENDENT AGGREGATORS

OVERVIEW

Aggregators provide an important route to market for DSR providers. Aggregation can be defined as the act of grouping different customers within the power system (i.e. consumers, producers, prosumers) to act as a single entity when engaging in electricity markets or selling services to the TSO or DNO (Burger *et al.*, 2017). Through aggregation the value of DSR can be enhanced by bringing together providers who would be too small to participate in the markets individually. In addition aggregators have detailed knowledge of these markets which many small DSR providers might lack. Aggregation can also increase the reliability of DSR by bringing together resources from across different industries and geographies (CRA, 2017a).

REGULATORY AND MARKET BARRIERS TO INDEPENDENT AGGREGATORS

As independent aggregation is a relatively new concept in GB there is as yet no legally defined role for these actors. Article 17.3 of the EU 'Winter Package' (European Commission, 2016a) requires member states to define frameworks for independent aggregators along principles that enable full participation in the market. However, currently in GB, aggregators can only access some markets directly, whilst other markets can only be accessed through the supplier (i.e. the Wholesale Market and the Balancing Market).

The ability of aggregators to access markets varies across Europe. For example, in Germany, aggregators require agreement with the supplier before they can access the flexibility of the consumer, though this may be changing. In France, on the other hand, pre-determined arrangements allow aggregators to access all markets without negotiating first with a supplier (PA Consulting Group, 2016).

One of the key debates about the development of an aggregation component in the electricity market is the impact that aggregators might have on suppliers, particularly in relation to a supplier's demand position in the market (De Heer, 2015). Independent aggregators are currently independent of the supplier of the customer providing the DSR and as such are not responsible for the customer's metered supply. This means that independent aggregators are not currently able to register Balancing Mechanism Units (BMUs) and thereby participate in the Balancing Market (BM) (CRA, 2017a).

The 'Winter Package' states that aggregators should have the right to enter the market without consent from other market participants, and should not be required to pay compensation to suppliers or generators (European Commission, 2016a). This effectively means aggregators are not "Balancing Responsible Parties"[14] (BRPs) and can control their customer load without being exposed to imbalance pricing. It also means suppliers may not be able to fully invoice the difference between the consumers metered volumes and their full electricity procurement cost (Edwards, 2017).

[14] A balancing responsible party is a market role in power systems that is specifically defined to settle differences between the scheduled and actual values of consumption, generation and trade

Eurelectric argues that aggregators should be made BRPs and be financially responsible for keeping their positions balanced as this is consistent with electricity market principles. They can do this either through mandating aggregators' trade energy with suppliers or through ex-post correction of imbalance volumes (Eurelectric, 2017). Article 17.4 of the Winter Package goes on to state that aggregators should pay compensation under 'specific circumstances', but Eurelectric argue this does not clarify the situation (Edwards, 2017).

Whilst aggregation might be a relatively new option in the EU, in the US independent aggregators are highly active and market rules in New York (NYPDS, 2014) and California (California ISO, 2015) are designed to ensure that they flourish; whereas in Europe it can be argued that debate to date has been focussed around the value or disvalue of superimposing third party aggregators over retailers (Burger *et al.*, 2017).

BEIS & Ofgem have already identified some of the issues facing aggregators in the 'Smart Systems and Flexibility Plan' (BEIS and Ofgem, 2017a). Additionally, Ofgem adds further detail and affirms that balancing responsibility should rest with the party which created them, and that the bulk energy issue is most efficiently dealt with in the contractual arrangements between the supplier and consumer (Ofgem, 2017g).

Alongside its view Ofgem published a report by CRA on the economic value of DSR participation in the BM, estimating benefits in the range of £110mn to £400mn by 2020 (CRA, 2017a). The introduction of Modifications P344 and P355 intended to implement changes to the BM, (as discussed in Section 3.4) would enable smaller generators to access the BM through aggregating themselves into a larger BMU; which could be through the use of an independent aggregator if aggregators are considered alongside P355.

These issues and BEIS/Ofgem's proposed actions are summarised in Table 10.

Table 10 Barriers for Aggregators

Barrier	Possible Solution
No legally defined role for independent aggregators	To enable independent aggregators to enter the market at scale, it is critical that their role and responsibilities are clarified. In particular, it is important that the relationships between suppliers, balancing responsible parties (BRPs), and independent aggregators are clear, fair, and allow for fair competition (SEDC, 2017)
Balancing Mechanism – no current route to access BM	Create a new route for independent aggregators to access the BM. Will need code modifications.
Capacity Market	Simplify metering requirements. Stack revenue streams across markets.

Aggregators can't change the portfolio of DSR participants which make up a CM unit. Therefore, if one participant withdraws the whole contract is nullified.	Enable asset reallocation.
Other markets	Ensure a level playing field for access to additional energy markets where aggregators can be accommodated efficiently. Improve signals for network usage.
Measurement - Potential for gaming	Measure DSR volumes and ensure that baseline gaming opportunities are mitigated.
Cost reflective pricing	Allow for payments to cover the cost of energy sold on by the aggregator, which was initially sourced by the supplier to help ensure a more cost-reflective supply curve at a system level and a level playing field between different technologies.
Balancing responsibility and delivery risk	Both balancing costs and delivery risks should be borne by the parties that created them.

Sources: (BEIS and Ofgem, 2016) (BEIS and Ofgem, 2017a) (Ofgem, 2017g)

6.4 THE ROLE OF STORAGE

OVERVIEW

Storage will be a key component of the LEM due to its flexibility and diversity of uses. It can be deployed at distribution, commercial and domestic level providing a wide range of revenue streams for LEM participants.

The utilisation of storage in constrained areas of the network can provide cheaper NWA solutions to DNOs through the optimising of supply and demand and can help generators overcome issues with curtailment at times of network stress.

BEIS and Ofgem are supportive of enabling the storage market to develop in GB and have identified a number of regulatory changes which could encourage more storage in the 'Smart Systems and Flexibility Plan' (BEIS and Ofgem, 2017a).

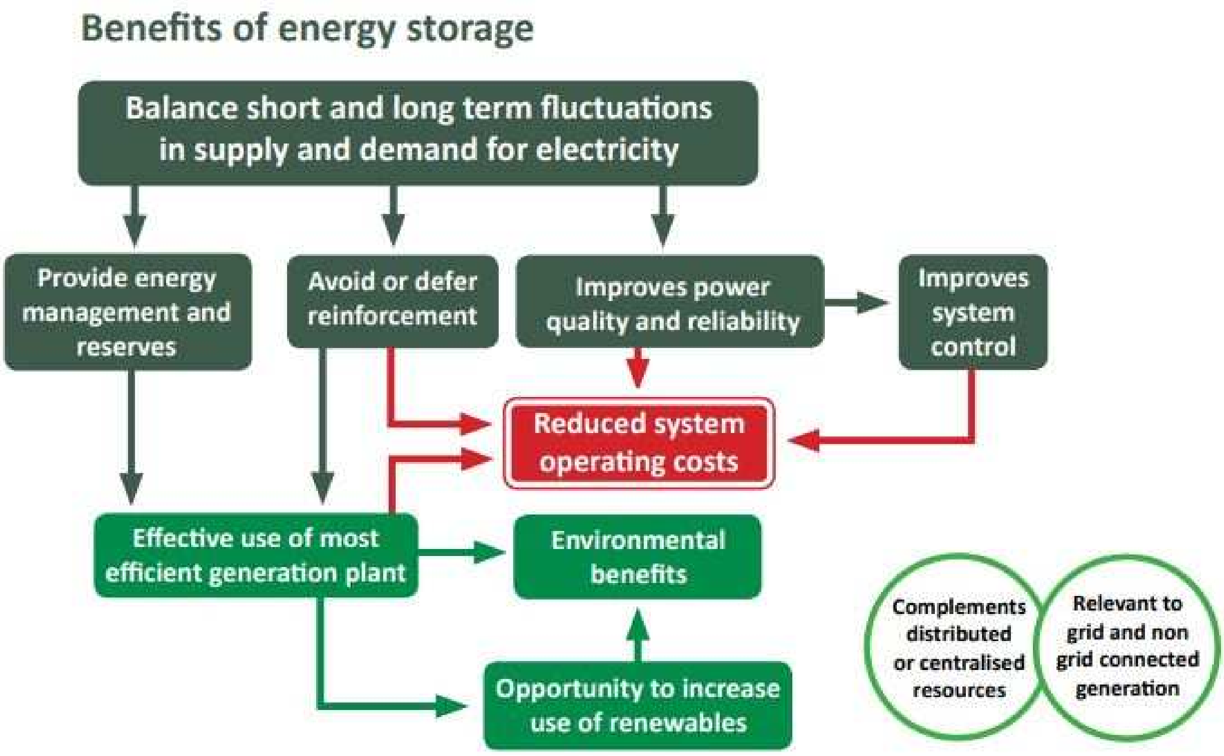
BENEFITS OF STORAGE

Storage technologies can contribute to electricity system operation, and can in particular alleviate some of the issues associated with variable renewable generation and may enhance the economics of household generation. Its potential benefits include:

- Provision of ancillary services to the System Operator and DNOs
- Supplying electricity during outages, enhancing system stability and resilience
- Storing power produced by renewable sources when output is high, and exporting the power when generation is low (or prices are high)
- Storing power during times of network stress or to overcome a network constraint
- Reducing peak loads

Depending on siting, storage can reduce losses on transmission or distribution lines, as well as reducing the need for network upgrades or reinforcement by optimising supply and demand at specific locations. The Electricity Storage Network consider that in the long-term, storage could be one of the most important tools to reducing the overall system operating cost by optimising generation, transmission, generation and supply (Electricity Storage Network, 2014)

Figure 7 Benefits of energy storage



Source: (Electricity Storage Network, 2014)

There are many different types of storage which fall under six main categories:

1. Solid State Batteries - a range of electrochemical storage solutions, including advanced chemistry batteries and capacitors
2. Flow Batteries - batteries where the energy is stored directly in the electrolyte solution
3. Flywheels - mechanical devices that harness rotational energy to deliver instantaneous electricity
4. Compressed Air Energy Storage - utilising compressed air to create a potent energy reserve
5. Thermal - capturing heat and cold to create energy on demand
6. Pumped Hydro-Power - creating large-scale reservoirs of energy with water
   (Source: Energy Storage Association website)

Storage can be extremely flexible in terms of scale – large installations can be connected to transmission networks, while smaller scale storage can be deployed at distribution, commercial and even household level. This flexibility, however, contributes to the difficulties of drawing up policies and regulations designed to encourage the greater use of storage technology, as a 'one size fits all' approach will not reflect the diversity of services that the technology can offer at different scales.

Storage can either be installed in-front of or behind-the-meter. Most storage at the moment is utility scale 'in-front of the meter' storage (85% of all storage in the USA in 2016) (Maloney, 2017) with pumped hydro storage representing around 95% of total global storage capacity. In the UK in 2016 there were 39 installed stand-alone energy storage projects (REA and Energy Storage UK, 2016).

However the behind-the-meter storage market is due to grow considerably in GB over the next few years due in part to the benefits that can be gained with combining battery storage with solar PV and also with the introduction of half hourly domestic settlement (REA and Energy Storage UK, 2016). Behind-the-meter means that the storage is installed on a customer's property and on the customer's side of the electricity meter. Being able to store excess generation behind-the-meter will enable customers to utilise more of their own generation, thus reducing the need to purchase additional electricity from a supplier. Currently this would also mean avoiding network charge costs as electricity generated and consumed on site behind-the-meter is exempt from these costs. However, this position could change through the current Targeted Charging Review taking place (see Section 5) which seeks to re-evaluate who should pay for what in network charging.

Battery storage had agreements awarded for the first time in the 2016 T-4 Capacity Market auction (see Section 3.5) and has been performing in various ancillary services. National Grid introduced the Enhanced Frequency Response (EFR) service in 2016 aimed predominantly at battery storage assets providing frequency response in one second or less. The tender to secure 200MW of capacity attracted interest from over 70 projects with a cumulative capacity in excess of 1.3GW, highlighting the interest from storage developers. This was the first signal in GB of a specific revenue stream for battery storage that has triggered such interest (Papadopoulos *et al.*, 2016). However, in the 'Product Roadmap' published by National Grid in December 2017 this service has now been removed in line with the rationalisation of products (see Section 3.2). This isn't necessarily a problem for storage however, as the new products have already seen significant interest from storage providers (Pratt, 2017) and they should be easier to access for the reasons set out in Section 3.2. Indeed National Grid expects electricity storage capacity to grow rapidly over the next few years, nearing 6 GW by 2020 (CRA, 2017b).

Battery storage currently has access to several revenue streams as identified in Figure 8 and discussed previously in Section 3. The ability to stack revenues across these different streams will be important for the financial viability of storage providers.

Figure 8 Current Battery Revenue Streams

Source: (CRA, 2017b)

* System services are referred to as 'ancillary' services throughout this document

REGULATORY AND MARKET BARRIERS

BEIS and Ofgem are supportive of enabling the storage market to develop in GB as can be shown by their 'Call for Evidence' (BEIS and Ofgem, 2016) and the 'Smart Systems and Flexibility Plan' (BEIS and Ofgem, 2017a). In those documents, they identified a number of areas where policy or regulation could contribute to encouraging more storage, and proposed a number of solutions to enhance the environment for more storage (see Table 11). They have also followed up on these solutions by issuing consultation documents later in 2017 on 'Clarifying the regulatory framework for electricity storage: licensing' (Ofgem, 2017a) and 'Draft Guidance for Generators' (Ofgem, 2017b).

Table 11 Barriers to Storage

Theme	Barrier	Possible Solution
Network connections	Limited understanding of the complexity surrounding the need for both import and export capacity, and the differing uses, sizes and locations of connections can result in lengthy and expensive connections.	Ofgem will work with industry and DNOs to improve the connection process, for example by introducing flexible connections which will be cheaper and quicker. However, flexible connections (i.e. ANM) can have a detrimental financial impact on distribution connected storage in that batteries could be prevented from

		discharging at optimal times due to DNO contractual limitations. Cross reference with Section 4.2.
Network charging	Distribution connected storage currently pays both import and export network charges as it 'uses the network for both'.	The Targeted Charging Review (Ofgem, 2017o) considers the current system of network residual charges to ensure storage doesn't pay the 'demand residual' element of network charges at T & D level. However, see Section 5 as the TCR has wider implications.
Regulatory clarity	Different definitions of storage are used for different regulatory purposes, including licensing and the capacity market. Need to develop a common definition for use across different policy areas.	Ofgem consulted on the regulatory framework for electricity storage in Sept 17 (Ofgem, 2017a) and affirmed that the Electricity Act 1989 will be amended to include a definition of storage as a distinct subset of the generation asset class. Storage is also being defined in the Grid Code (GC096).
Final consumption levies	Several levy costs are applied twice to storage (once on charging and once on supply), including the costs of the Renewables Obligation, Feed-in Tariff, Capacity Market and the Climate Change Levy. This results in double counting of supply to the consumer on the same electricity.	Storage should be exempted from final consumption levies. Ofgem are therefore proposing a new licence condition 'Condition E1' to provide clarity that 'The licensee shall not have self-consumption as the primary function when operating its storage facility' (Ofgem, 2017a) to overcome the double counting issue.
Planning	As storage is yet to be classified or defined, it is unclear how storage fits within the planning framework. Storage is currently defined in planning as an 'electricity generating station' causing uncertainties over whether it should be in national guidance or dealt with at the local planning level.	A review of planning legislation will assess whether guidance can be simplified i.e. by including a national planning threshold for storage and associated planning guidance. However, there is no timescale set for amending this.

Co-location	Lack of clarity how storage might interact with renewable installations receiving support under the RO, CFD or FIT regimes	Ofgem produced Draft Guidance Dec 17 (Ofgem, 2017b) to provide clarity on when storage can co-locate alongside renewable generation without risking agreements. Ofgem consider that where the scheme requirements are being met, storage can be deployed without risk to accreditation, although decisions would be made on a case-by-case basis.
Ownership	The EU 'Winter Package' states that DSOs should not be allowed to own, develop, manage or operate storage in order to promote market competition.	BEIS & Ofgem announced that DNOs should not own or operate storage to allow market competition. This should be beneficial to the LEM but some DNO's have argued against this,[15] although WPD have signaled that their position is that DNO owned / operated storage should only be used as a 'last resort' if the market fails to deliver.

Sources: (BEIS and Ofgem, 2016) (BEIS and Ofgem, 2017a) (Ofgem, 2017a)

While these measures will go some way to addressing the current regulatory ambiguity surrounding storage in GB, other issues have also been identified by GB stakeholders, including:

- Domestic HHS to encourage domestic take-up of storage combined with PV
- Storage to be acknowledged by BEIS as an essential part of the energy mix, with targets for adoption set out in a Storage Strategy (either as a % target or a MW target)
- Renewable subsidies should be provided for storage to incentivise take-up
- Financial support needs to be given for R&D projects
- An analysis of the network savings that could be achieved through deferment of network upgrades should be undertaken (with financial remuneration available to storage providers for providing these savings)
- Flexible connections controlled by the DNOs can limit output periods
- An agreed definition for electricity storage that allows for incremental revisions as technologies mature
- Education and dissemination of lessons learnt to industry and to policy makers
- Development of local energy markets utilising storage as part of local supply.

Sources: (Electricity Storage Network, 2017) (REA and Energy Storage UK, 2016)

As with any new technology, adopting a strategy for technology development and deployment can contribute to the rate and scale of dissemination, in part because such an approach can contribute to

[15] https://www.cleanenergynews.co.uk/news/storage/dnos-should-own-and-operate-battery-storage-funded-by-grid-services-norther

investor confidence. A strategy for storage would not be straightforward, given that it is so flexible in terms of scale. Its potential to interact with other sectors also needs to be taken into account, especially given the interaction between storage (battery) technologies and the anticipated increase in uptake of Electric Vehicles (EVs). The strategy would therefore have to be multi-scale and multi-sector, with a long term vision of the development of electricity networks (IRENA, 2015).

This is a considerable task. As an interim measure, the REA suggests a short term 'quick fix' (REA, 2017) announcement from BEIS to give the market confidence that progress will be made, and to unlock some deployment, before the longer-term solution to amending primary legislation is made. It is worth pointing out that such a quick fix approach might be desirable in the short term, but measures put in place should not result in conflicts with any longer term strategic approach.

In time, cost reductions associated with battery storage should drive down the costs of EVs and make storage increasingly attractive for a range of customers. New storage markets could also emerge, such as the car industry selling older batteries from EVs into the domestic and I&C markets, making it a more affordable option for customers to adopt.

LESSONS FROM CALIFORNIA

Californian market rules did not until recently support the ability of energy storage resources to stack more than one service. The California Public Utilities Commission recognised this as a market failing which reduced the economic value of storage to the electricity system. The Commission therefore approved eleven new market rules in January 2018 (CPUC, 2018) aimed at enabling resources to stack value and revenue streams through the delivery of multiple services to the wholesale market, distribution grid, transmission system and other venues.

The Commission identified five 'service domains' for provision of services (customer, distribution, transmission, wholesale market and resource adequacy) with a pyramid hierarchy of operability i.e. the customer domain can trade in all markets; the distribution domain can trade in all markets except the customer market and the transmission domain can trade in all markets except the distribution and customer market. The objective being to enable storage systems to stack value by being able to deliver multiple services to multiple markets.

These services were then divided into 'reliability services' and 'non-reliability services', with the former always having priority in dispatch.

The Commission clarified that these rules are interim and may change in time due to lessons learnt through their implementation:

> "we are cognizant that these rules will need to evolve over time as market prices, penalties, and services continue to evolve, and that allowing some flexibility for storage resources to provide multiple reliability services in the near term may provide important learning opportunities to inform future policymaking (CPUC, 2018)."

The Commission's commitment to act swiftly to remove the economic barriers to storage and then keep a watching brief as the policies unfold should be applauded. This decision is reminiscent of the REA's call for BEIS to issue a quick fix to ensure market confidence, but with the caveat that any measures adopted should not conflict with longer term strategic goals. This approach also fits with the 'plan, monitor and manage' approach which is inherent in the UK planning system.

6.5 THE ROLE OF PEER-TO-PEER TRADING

OVERVIEW

Peer-to-Peer (P2P) energy trading can be defined as local energy trading between participants, where the excess energy, or demand reduction, from many small-scale DERs is traded amongst local individuals and organisations. Essentially, allowing households to become small energy providers (adapted from Murkin *et al.*, 2016) and (Long *et al.*, 2017).

P2P trading would appear to be one of the fundamental values of a LEM; offering the ability to trade electricity locally, within a defined area and between defined participants without the need for a third party licensed supplier (TPLS). However P2P trading in GB currently faces several regulatory and financial hurdles as will be discussed, the main one being that the model represents a fundamental shift from the supplier hub model.

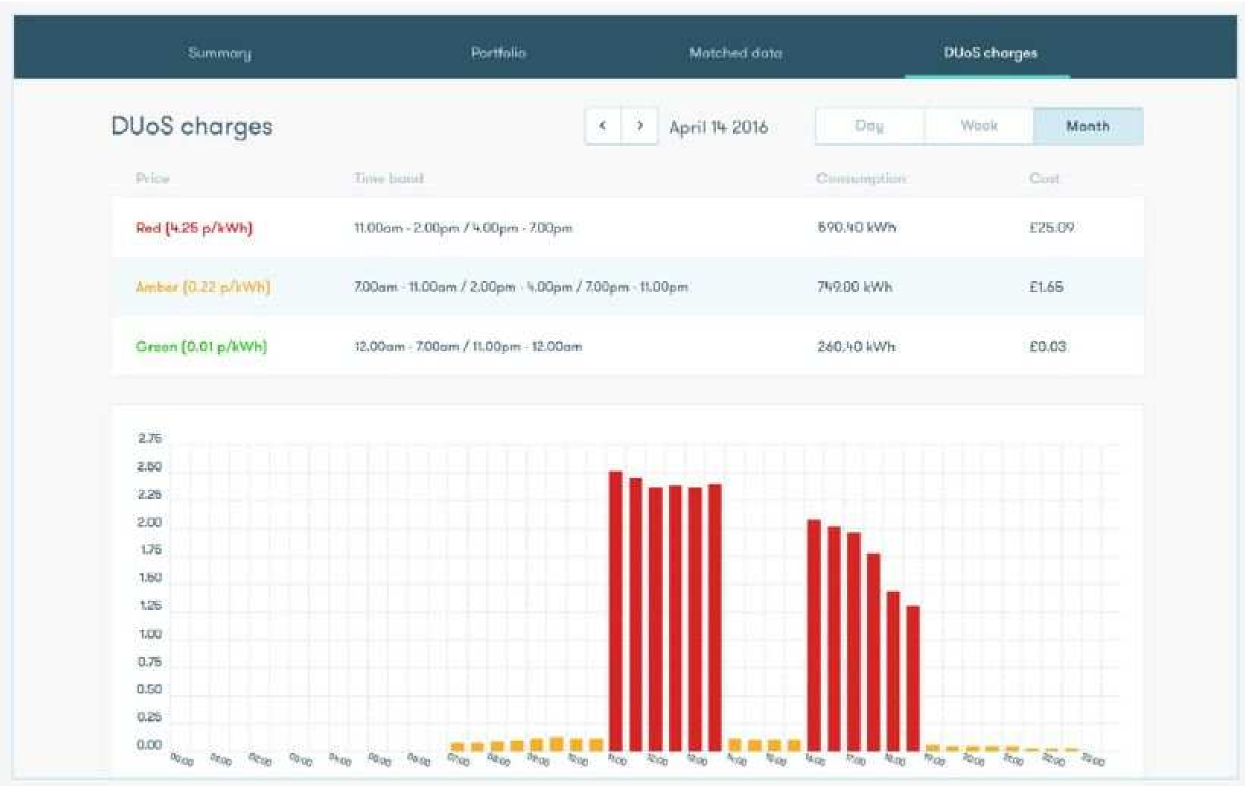
PICLO

One of the closest examples of P2P that's commercially operating in GB at present is the Piclo model developed by Open Utility and partnered with supplier Good Energy. However, Piclo is not as yet a true P2P trader, due to the need to partner with a TPLS.

The Piclo model provides a platform to match renewable energy generators with local customers, based on current supply and demand from measured smart meter data. The platform gives customers the option to select where their energy comes from and from what source i.e. wind, hydro or solar. This can result in a better Power Purchase Agreement (PPA) deal for generators (Hall and Roelich, 2016). However, the model requires the software platform operator to partner with a TPLS, in this case Good Energy, for the billing and balancing functions (*ibid*) in compliance with current GB regulations which necessitate that at present all electricity trading must be via a licensed supplier (Ofgem, 2017e).

Piclo provides visualisation of customers DUoS charges (see Section 5) to incentivise consumers to shift and reduce their electricity usage during peak times (Open Utility, 2016). Based on a time-of-use calculation for half-hourly metered import customers, the charges are split into red, amber and green time periods as shown in Figure 9.

Figure 9 Piclo Visualisation



Source: (Open Utility, 2016)

Piclo is not however currently able to achieve reduced DUoS charges for consumers based on consumers purchasing locally generated electricity. Open Utility have held discussions with DNOs and Ofgem, arguing that if it can be demonstrated that only a few kilometres of the network are utilised between generator and customer, then there should be potential to reduce the system charge. Trial data from the Eden Project indicates that local generation matching could reduce their annual DUoS charge by up to 39% or £20,000 (Coyne, 2017).

Piclo commenced trading in October 2015 but is currently limited to I&C customers only (due to the necessity of having half hourly settlement), although it is hoped to extend the model to a residential trial in Scotland as the next step. Piclo also recently won two international contracts partnering with supplier ERG in Italy (June 2017) and with Essent in the Netherlands (September 2017).

The Piclo model is not currently bounded by geography, with generators and consumers in different network areas able to trade on the Piclo software exchange (Hall and Roelich, 2016). Therefore, this model does not as yet provide a solution to issues to do with local balancing, overcoming network constraints and curtailment and does not provide participants with financial rewards (in the form of lower network charges) for doing so. And although it allows renewable generators to match with demand customers it does not allow for Customer A to trade their excess on-site generation to Customer B.

REGULATORY AND MARKET BARRIERS

A true P2P market would allow anyone to be able to sell their excess generation or demand reduction to whomever they choose within their locality, including from domestic customer to domestic customer. However, the current electricity trading regulations do not allow for this to happen due to several regulatory and market barriers as described below.

One major regulatory barrier to be overcome is that currently all transactions must be made through a licensed supplier and customers can only have ***one*** licensed supplier (as with Piclo). It is therefore not a possibility for a domestic prosumer (say with solar PV) to ***sell*** any excess generation to anyone else – it currently either has to be stored on site, or sold to the grid via the supplier. On the reverse side, it is also not possible for a customer to ***buy*** electricity from anyone other than their sole contracted supplier. In a world where households can purchase many different products from many different companies, this 'supplier hub' model is frustrating.

Ofgem have recognised this as a barrier to establishing a local P2P market, which they include in their 'Future supply market arrangements – call for evidence' launched in November 2017 (Ofgem, 2017e). The CfE seeks views on whether the current supplier hub arrangements are fit for purpose and where any future regulatory change should be focused and why. Although Ofgem are careful not to make any promise of regulatory change at this stage, they have stated that initial views on the way forward will be published in Spring 2018 (see Section 2.1).

The next major regulatory barrier (interlinked with that above) is with billing and settlement. At present, all electricity that passes through a customer's meter is purchased from a single licensed supplier who bills the customer based on total volume consumed. There is no mechanism to determine whether that electricity came from a different provider (such as in a P2P transaction) leading to the customer potentially paying twice on the P2P volume consumed. The amount paid to the licensed supplier would also include all relevant network charges and environmental policy surcharges.

On the reverse side to this, whilst the supplier would on the one hand receive monies for electricity they hadn't provided; they could also be charged imbalance fees if the volume of electricity consumed was larger than those contracted by the supplier via the market.

There are also wider technological issues regarding metering. As stated above, Piclo is only available to I&C customers at present due to the need to have HHS. However even with the completion of the smart meter rollout and domestic HHS (see Section 6.1) there could still be problems regarding metering. For instance, if regulations are adapted to accommodate P2P transactions, and customers are able to buy from more than one supplier at a time, it is unknown how this will be managed by participants with the current metering infrastructure. Advice from one industry expert[16] was that it is unknown whether the new SMETS2 meters would be able to handle more than one supplier per meter point. One solution might be via Blockchain technology (discussed later in this section) or via innovative software developed by a P2P marketplace, such as Piclo. However this still leaves issues relating to which supplier would hold the balance of power, which supplier would be responsible for balancing obligations, security obligations and environmental policy obligations such as FiT payments?

[16] Interview with industry expert 4 on 08/01/18

As shown above Piclo have not been able to achieve reduced network charges for participants. This aspect should be reviewed during the current Targeted Charging Review (Ofgem, 2017o) and the electricity network access project (Ofgem, 2017k) (see Section 5). Current thoughts at Ofgem though[17] are that charges should be fair for all users of the system; which in theory could lead to a charge per transaction in a P2P market to ensure that system costs are covered.

Another issue to be explored regarding selling excess generation in a P2P transaction relates to Feed in Tariff (FiT) payments. At present accredited small-scale renewable technologies receive both generation and export FiT payments from participating licensed suppliers. Export payments are calculated as 50% of the electricity generated, and are currently valued at 5.03p per kWh (Ofgem, 2018a). However, if exported generation was sold privately in a P2P transaction there would presumably need to be a mechanism which recognised that fact, relieving the supplier of the obligation to pay. Alternatively, the generating customer could opt out of all export payments to simplify the issue. Either way, the loss of the FiT export payment would reduce the profitability of any generation sold.

Due to the above issues it is difficult to see how any monetary profit can be made by participants through P2P trading in the current regulatory environment. However, there are wider system and environmental benefits to be captured given the correct impetus.

Local P2P trading could be beneficial to network management if all transactions occur within defined GSPs. This would reduce network constraints, if trading occurred below the constraint area or bottleneck. This in turn could reduce the likelihood of curtailment for existing renewable generators and allow for additional network connections to be made for currently stalled projects.

Ofgem have recently received expressions of interest in P2P trading through their 'Regulatory Sandbox' trials (Ofgem, 2017h). The trials allow developers to test their products without meeting all of the usual regulatory requirements. P2P trials currently at the agreement stage through the Sandbox include:

- A consortium led by EDF – trialling a P2P local energy trading platform enabled by Blockchain which allows residents in urban areas to source their energy from local renewables and trade that energy with their neighbours.
- Empowered – trialling a local P2P energy trading scheme aimed at enabling consumers to trade electricity directly with each other to yield benefits for the local community and the wider electricity system.

BLOCKCHAIN

Blockchain could be an important enabler to unlocking the P2P market (hence its use within the EDF trial outlined above). Due to the ability for all parties within the blockchain to transact with each other, without the need for an external verifier, this could allow prosumers to sell to their neighbours without the verification of a TPLS (Hoggett, 2017) if regulatory barriers are removed.

Blockchain is described by its developers as a distributed ledger that enables individuals to transact with each other without the need of a trusted third party, like a bank. The ledger has now evolved into a

[17] Interview with industry expert 4 on 08/01/18

variety of models that can be applied to different business problems and dramatically improve the sharing of information (Hancock and Vaizey, 2016). These blocks are verified, and cannot be altered or removed without changing every transaction within them (Lempriere, 2017). The consensus is, that whilst the work behind blockchain was for financial transactions, blockchain has far wider potential, and is already being introduced into other sectors, including the energy sector (Hoggett, 2017).

As well as providing confidence for potential P2P transactions, blockchain can give individuals more control over their personal data, which could become increasingly valuable and important in the distributed energy system. It does this by enabling people to own and maintain their data and make decisions on who can and can't have access to it within the blockchain. Blockchain therefore can provide new ways for people to participate within markets (Hoggett, 2017).

However there are issues around data privacy and consumer trust with blockchain which need to be clarified and in this respect Ofgem is already holding roundtable discussions with industry to try and identify potential pitfalls for implementing blockchain in the GB energy system (Ofgem, 2017l). Issues discussed so far include the trustworthiness of blockchain, participants' dispute resolution and who should underwrite transactions.

INTERNATIONAL P2P EXAMPLES

P2P trading has been receiving much attention across the world with several innovators currently undertaking trials in different settings.

The best-known example of P2P trading is the Brooklyn Microgrid in New York which was the first ever pilot micro-grid project developed using blockchain technology (Brooklyn Microgrid, 2017). The microgrid, known as the TransActive Grid, was created in 2016 by LO3 Energy in conjunction with Siemens.

LO3 Energy uses Ethereum Blockchain software linked to PayPal to provide the means for members to settle transactions (Burger, 2016). LO3 Energy first started testing the concept in just one street but they are now expanding into the surrounding neighbourhood. Residents with solar PV can sell their excess energy to their neighbours, in P2P transactions (Lempriere, 2017). However, the system is not linked to settlement and is currently more expensive than buying electricity from the utility company.

Similarly, Shanghai-based Energo Labs is using Qtum Blockchain technology to trial P2P transactions in microgrids in the Philippines. Participants can buy and sell electricity via the Energo phone app and all data is quantified by Energo smart meters (Domingo, 2017).

P2P trials are also taking place elsewhere internationally, such as Vandebron in the Netherlands (Vandebron, 2017); SonnenCommunity in Germany, which enables community members to share their excess solar PV electricity via sonnenBatteries in a virtual pool system (Sonnen, 2017) and in Perth Australia, supplier Power Ledger is running a trial which involves 10 households in a gated community trading their excess solar energy between each other (Vorrath, 2016).

Table 12 Barriers to P2P Trading

Theme	Barrier	Possible Solution
Licensed Supplier Issue	Customers cannot trade electricity between themselves without a TPLS. The supplier undertakes all the supplier obligations - mitigating the imbalance risk, paying use of system charges etc. In addition, customers can only have one licensed supplier per property. However, if customers were able to have more than one supplier this would in turn raise issues regarding the balance of power, which supplier would be responsible for balancing obligations, security obligations and environmental policy obligations etc.	'Future supply market arrangements – call for evidence' launched in November 2017. Initial way forward expected Spring 2018. Regulatory Sandbox trials commencing in conjunction with Ofgem to assess barriers.
Billing and Settlement	Billing and settlement also has to be through one licensed supplier – which could potentially lead to double counting if issue not addressed.	As above.
Metering	Unknown whether SMETS2 meters would be able to handle more than one supplier per meter point. Smart meter rollout is not anticipated to be finalised until 2020. HH settlement is currently an option for domestic and small business customers but is not as yet mandatory. Issues with accessing smart meter data – DNOs and P2P platform providers cannot see customers smart meter data due to data protection issues.	Need sophisticated metering to determine what volume is being sold P2P. HH settlement would be needed in order to participate. Resolution needed on who can access smart meter data.
Data	DNOs currently only have limited visibility down to 33kV asset level with no visibility below this. They also have no real understanding of the amount of DER operational on the network at the street / household level. A more granular level of detail will be needed in order to establish what is happening at the customer / connection level.	Granular data and sophisticated IT solutions are required at the DNO level. WPD have signaled that they anticipate this to be in place (for their own network areas) by the end of RIIO-1 (2023). This data should be publicly accessible in order to facilitate P2P exchanges. BEIS & Ofgem should provide regulatory clarity over data – in particular encourage data sharing between the SO, DNOs and suppliers at the lowest possible granularity. This can include data regarding network constraints and the availability of DER on the network.

Blockchain	Blockchain is being hailed as a revolutionary mechanism for trading energy but the blockchain process itself is hugely energy resourceful (Proof of Work – quantum computer cracking cryptography) or determined by those with the most financial claim (Proof of Stake) and transactions are not financially regulated.	Ofgem are considering questions around security, customer acceptance, dispute resolution and underwriting in blockchain scenarios.
Network Charging	Reduced DUoS charges are not currently available without a derogation.	All of network charging will be reviewed through the Charging Futures work on residual and forward-looking charges. Current thoughts at Ofgem are that network charges should be fair for all users and so there could potentially be a charge per transaction on all P2P trading.
FiT	Unknown how P2P will affect FiT payments – if export tariff has to be forfeited this reduces profitability.	FiT export tariffs currently based on 50% of generation total – and paid by the supplier. Customers could either forfeit export payments or sophisticated metering could establish what has actually been purchased elsewhere.
Financial Reward	It is not easy to see a financial benefit to P2P trading due to the above issues and if customers can receive higher payments from alternative markets they will probably seek those first.	Although there appears to be little financial reward at present due to regulatory issues more profit could be realised through reduced network charges and the removal of trading through a TPLS. There could also be a more profitable solution in demand generation coupling i.e. if a generator could offer DTU to a local business in order to overcome curtailment this could lead to a cheaper electricity deal for the business whilst the generator could export when they would otherwise have been curtailed.
Customer engagement	Domestic customers may like the idea of being able to trade with their local community but they may require a high level of automation in order to participate. For example, the Wadebridge Sunshine Tariff ToU trial saw more demand shifting when processes were automated (Regen, 2017).	P2P platforms should offer automated solutions for domestic customers who would prefer this.

6.6 THE ROLE OF LOCATIONAL MARGINAL PRICING

OVERVIEW

The underlying principle of locational marginal pricing (LMP) is that the energy price varies from one location to another location in the presence of congestion and loss in the system (NPTEL, 2017). Therefore, in a LMP market there is not a single wholesale energy price but potentially many different nodal prices. These are established by using an algorithm which takes into account losses and network constraints (Ofgem, 2017k). Currently there is no differential made in the GB wholesale market price of electricity which reflects these different nodal prices, but if they were recognised and valued at the distribution level, LMP could incentivise the development of DER at more optimal locations within the network and help relieve network constraints.

BENEFITS OF LMP

A study by the University of Cambridge Energy Policy Research Group in 2017 highlighted that the scope for LMP in GB has increased recently with improvements in computing and smart metering. They claim that a move towards more granular electricity prices could help improve location decisions for future generation investment and enhance the value of greater system decentralisation (Newbery *et al.*, 2017). For instance, with LMP excessive siting of RES in a particular area could depress local power prices and thus signal the need to locate subsequent RES installations elsewhere on the network (*ibid*).

The advantages to LMP at the distribution level would be that prosumers could get a better reflection of the value of their power when selling any surplus at high value locations; and that the DNO could see more assets being provided at optimal locations on the network for managing local distribution network congestion. LMP therefore has the potential to reduce network congestion through increasing generation / demand at high value locations and flattening the load in constrained areas.

REGULATORY AND MARKET BARRIERS TO LMP

A report by the Massachusetts Institute of Technology (MIT) explains that in many international power systems, the spatial differentiation of prices due to network losses and constraints is ignored, with LMP occurring mainly at transmission level in North and South America and Australia (MIT, 2016). However, to their knowledge, LMP is not currently used at the **distribution** level in any power system internationally.

LMP is an untried system in GB, and indeed anywhere globally at the distribution level. Ofgem have signaled that they believe LMP to be highly complex and that it has unclear potential in its application at distribution level. They consider that it is also 'very difficult to see how LMP could be implemented in a way consistent with the current self-dispatch model' (Ofgem, 2017k). Ofgem have therefore discounted LMP as a concept in their recent consultation on the Reform of electricity network access and forward-looking charges; however, they do state that LMP is a key area where signals need to be better (*ibid*).

Cambridge's Energy Policy Research Group agree that LMP is difficult to implement in self-dispatch power exchanges and is usually managed in central dispatch markets internationally. However, in GB, there have been arguments made that balancing charges should be nodal, so that generators face the right prices for marginal output decisions (Newbery *et al.*, 2017) .

However the main barrier to LMP in GB is likely to be that it is discriminatory to customers based on their location. Whilst some customers would achieve a reduction in wholesale prices, others would see much higher prices being applied. This would be politically difficult to implement and Ofgem, in their role as regulator, are likely to discount LMP for domestic customers at least on those grounds.

Table 13 Barriers to LMP

Barrier	Potential Solution
It is likely that Ofgem will consider LMP to be discriminatory, as customers in one location would pay higher wholesale prices than customers living elsewhere on the network; thus making LMP politically infeasible. Ofgem are not considering LMP during the current network charging reform.	In Ofgem's role as regulator they will want to evaluate whether LMP is discriminatory to customers. However they may wish to consider whether there is a different case to be made for I&C customers rather than domestic customers.
Distribution level LMP is not used in any international energy market.	LMP is completely untried at the distribution level.
LMP is not suited to the self-dispatch wholesale market model.	LMP is better suited to power markets with central dispatch, where LMP can achieve a more efficient dispatch to avoid congestion. However in self-dispatch power markets, with liquidity of pricing, LMP isn't a consideration at present and its effectiveness has been questioned (Singh *et al*., 1998). In GB, arguments have been made for balancing charges to be nodal, so that generators face the right prices for marginal output decisions (Newbery *et al.*, 2017).
Data Gap - this model requires the DNO to have data on the real-time power flow on the network and an understanding of what's happening both behind and in front of any network constraint.	This data is not at present available although WPD have set out timescales within their DSO Transition Programme for delivering new data and IT products. These are expected to be delivered by the end of ED-1 in line with WPDs stance of being 'market ready' by 2023.
Data sharing.	Once these data systems are available at the DNO level clarification will be needed regarding data sharing between the DNO and third parties.

SECTION SUMMARY

The 29 actions identified in the Smart Systems and Flexibility Plan are a good building block towards removing regulatory barriers for flexibility providers. In addition, research initiatives through the Sandbox trials and round tables are welcomed. Ofgem should now begin to seriously consider alternative market models and trading initiatives, in order to establish whether these regulatory improvements will actually provide the correct mechanisms to unlock future flexibility markets.

Indeed, it is known that there are still regulatory and market barriers to be overcome as discussed throughout this section and further decisions to be made. Lessons could also be learnt from other international arenas, especially California and New York, which are several years ahead of GB in their market transformation. They have already begun to identify and tackle their own barriers and acknowledgement of these by GB could assist a swifter implementation of market change.

7. CONCLUSION

The requirement to decarbonise the GB electricity system, alongside the falling costs of renewable technologies and developments in IT capabilities, provides GB with an opportunity for systemic change. However, in order for this change to be realised, BEIS and Ofgem need to provide the correct regulatory impetus to ensure a coherent market transformation. This has not happened to date, leading to a situation where renewable technologies are viewed by DNOs as system interrupters and the primary cause of network balancing and constraint issues.

Indeed, DNOs have been slow in acknowledging the system benefits which DER can offer if managed intelligently, leading to a situation where much of the change occurring at the network and market levels at present is reactionary. Change is therefore taking place in a disjointed piecemeal fashion, instead of being part of a coordinated effort to transform to a smart, flexible energy system, despite the stated intention of BEIS and Ofgem. This is in direct contrast to the energy system transformation occurring in New York and California, where Commissioners have seized the initiative and told distribution utility companies what needs to happen and by when to realise the potential of DER at scale.

This report has highlighted a range of regulatory and policy barriers to one particular innovative market model approach, the local energy market approach. The regulatory barriers faced by local energy markets could seriously hamper their operation in the short-term and inhibit them from being adopted more widely.

The transition from DNOs to DSOs should be the biggest game changer for enabling local energy markets. A fully functioning energy market at the distribution level would enable a wide range of services, adding value to the system through more intelligent management of renewables; thus enabling more renewable connections to be made. However, as shown, BEIS and Ofgem have left all transition decisions to be made by the network operators themselves, rather than setting a long-term strategic vision for future network development and operation. This has allowed the DNOs to set their own timescales and to decide for themselves what can and can't be achieved on individual networks.

The recent consultations held by Ofgem regarding network charging have also been disappointing. Ofgem's viewpoint that the mechanism for charging will be 'policy agnostic' is extremely short-sighted. How to charge for using the networks in future is a major decision which cannot be determined without first assessing how we want the networks to be used. If Ofgem want to enable DSO activities and localised energy market services such as P2P trading, then the network costs will be different to the traditional one-way passive energy flow costs. If Ofgem want to incentivise customer behaviour changes to increase the uptake of DER then the way in which we pay for networks should also be different. The mechanism and the policy intent should therefore be complementary, with the mechanism designed specifically to achieve the desired policy outcome as is happening in Australia. There the desired policy intent is to incentivise the uptake of DER and the charging mechanism complements this through support payments for NWA and a range of network tariffs and benefit sharing schemes related to customer behaviours.

In GB, whilst BEIS and Ofgem claim they want a 'smart, flexible energy system' they are taking a very inactive approach to achieving one. Although the proposed policy changes to storage requirements, access to markets and value stacking outlined in the Smart Systems and Sustainability Plan are welcomed, these can be seen to be the easy 'quick win' answers; whilst the more difficult questions remain unanswered. These include questions surrounding the enablement of DSR and independent aggregators to access the wholesale and balancing markets. Should independent aggregators be made Balancing Responsible Parties? How should the relationship between aggregators and suppliers be formalised? Providing solutions to these barriers would help unlock DSRs potential. However, due to poor policy development and design choices, that opportunity has not yet been realised (SEDC, 2017).

The Centrica LEM project is meanwhile attempting to navigate through this uncertain regulatory environment, aiming to enable new localised services which maximise the use of DER and which alleviate balancing and network constraints through the offer of intelligent solutions. However, initially, only use cases linking with existing markets (or not otherwise in breach of regulations) can be trialled. More innovative use cases will likely require derogations or simulated trials. This is disappointing for the current operation of the LEM, but there is still much to be learnt through the simulation process; as this will reveal a fuller extent of the regulatory and market barriers faced by LEMs, which in turn should inform future policy discussions to assist decision makers in enabling the smart, flexible energy system to emerge.

We therefore propose 6 interim drivers for change based on what we know now, and we will reconsider these drivers again at the end of the LEM project in 2020 when we have been able to analyse the actual impact of policy barriers on the LEM and its participants. At that stage we will have the qualitative data to show whether the barriers identified in this report are still considered to be the main barriers to a LEM; or whether there are additional barriers which haven't yet been revealed; or whether solutions to these barriers have been found in the meantime:

1. DSO TRANSITION – BEIS need to provide clarity on the DSO role and function as well as provide a strategic view of what needs to happen and by when in order to enable new innovative market solutions to emerge at the DSO level. We suggest that this should be before the end of ED-1 with an aim for all current DNOs to be offering DSO services during ED-2. DSOs also need to be incentivised though RIIO to undertake DER Plans of their networks to identify the value of DER down to the low voltage level which should enable domestic DSR and P2P trading. DSOs should also allow value stacking across markets in order for DER providers to realise the economic potential of their assets.

2. NETWORK CHARGING – during the current Charging Futures programme BEIS and Ofgem need to consider that in order for the market to become smart and flexible they need to incentivise the take-up of DER rather than penalizing participants. We agree that the networks need to be paid for, but until we have agreed on how we want the networks to be used in future we cannot agree on how much they will cost and how this should be paid. BEIS and Ofgem need to think holistically or face unintended consequences of uncoordinated decisions which will impede the speed of market transformation.

3. ACCESS RIGHTS – the Charging Futures programme is also currently debating new models for access rights to the network. Again a narrow viewpoint should not be maintained, with priority given to the model which best realises the potential for multiple small-scale DER to connect to the networks in a timely, cost-effective manner and which ends the current LIFO arrangements which undermine financial viability. This could include benefits to siting non-

domestic plant at lesser congested parts of the network. Barriers should not be introduced for domestic DER to connect to the network.

4. SUPPLIER HUB MODEL – the current model stifles P2P trading and the ability of small scale generators to access markets. The supplier hub model therefore has to change in order to allow innovative local market solutions to emerge. However, any new model will need to be able to address balance of power issues, metering, settlement and billing, whilst still protecting customers' rights.

5. ACCESS TO THE WHOLESALE AND BALANCING MARKETS – barriers to DSR and independent aggregators need to be removed in order for DSR to participate in these markets. Although the relationship between independent aggregators and suppliers need to be formalized, this cannot happen in advance of any changes made to the role of suppliers. Indeed, if the supplier role changes dramatically this relationship aspect may no longer be a barrier to DSRs participation in these markets.

6. DATA – BEIS & Ofgem should provide regulatory clarity over data which should be seen as a public good and shared as appropriate. In particular they should encourage data sharing between the TSO, DNOs, suppliers and platforms such as the LEM at the lowest possible granularity. This should include data regarding network constraints and the availability of DER on the network. It is acknowledged that the General Data Protection Regulation potentially make it difficult to access suitably granular meter data but this should also be explored.

Action in line with these six drivers would alleviate many of the barriers discussed within this report, opening up access for local participants to engage in generation, supply and balancing at the distribution network level. We therefore propose that if GB is serious about wanting to transform its energy system; is serious about meeting its decarbonisation targets; and is serious about creating markets that work for flexibility; that BEIS and Ofgem need to respond accordingly in order for this potential to be realised.

8. APPENDIX 1 - TABLE OF REGULATORY AND MARKET BARRIERS

Table 14 shows a summary of all the barriers to the development of local distributed energy markets identified throughout this report. As the electricity system is a multi-dimensional system the barriers identified in one area also have impacts on other areas throughout this report.

Table 14 Regulatory and Market Barriers

	Barrier	Possible Solutions
	SUPPLIER HUB MODEL	
1.	The supplier hub model provides a barrier for new trading arrangements.	Changes are needed to the supplier hub model to enable innovative local trading initiatives such as the LEM to fully participate in providing market solutions.
	ANCILLARY SERVICES	
2.	Difficult for smaller generators, DSR and storage to access.	Rationalisation of services to simplify process and align timescales for tendering. National Grid will also trial auctions from late 2018.
3.	Too many products.	Product rationalisation taking place currently.
4.	Multiple timelines for procurement.	Timelines to become aligned.
5.	Stacking of contracts.	National Grid have stated that stacking across products will be possible, which will increase financial viability for small generators / DSR providers.
	WHOLESALE MARKET	
6.	Difficult for small generators to access.	The clip size in the Power UK Continuous Market was reduced to 0.1 MW to assist with smaller generators accessing the wholesale market. However, the costs, regulations and licensing requirements are prohibitive to many small generators. If they choose the SVA route then they can only trade with one licensed supplier. This may be overcome through any changes to the Supplier Hub model. Additionally Modification P355 (see BM section) may be helpful in overcoming access to the BM requirement.

7.	No provision for explicit DSR in the wholesale market.	DSR currently can only be provided by the *supplier* of the DSR-provider as there is no mechanism for making bids and offers for a customer's potential demand, since there is no baselining of a customer's demand against which such bids/offers may be assessed. However Modification P344 to the BSC could be helpful.
8.	Lack of access for aggregators.	Create a new route for independent aggregators to access the BM. Will need modifications to the BSC as per BM below.
	BALANCING MARKET	
9.	Difficult for smaller generators to access the BM.	Modifications P344 & P355 'Introduction of a BM Lite Balancing Mechanism' should be helpful in this respect.
10.	Lack of access for Aggregators & DSR.	Modification P344 brings the BSC in line with Project TERRE requirements which states that DSR should have a level playing field with other forms of generation in accessing the BM. Also, aggregators should be considered alongside P355 (although they are currently excluded).
	CAPACITY MARKET	
11.	Access to the CM for RES.	RES receiving RO or CfD payments are ineligible to bid into the CM – which automatically rules out the majority of RES generation.
12.	Access to the CM for both DSR and Storage.	Although DSR and storage are accessing CM their respective share percentages are still very low. Decision to be made over whether their share % should be increased, or whether it is better to use these resources for real-time balancing of the system.
13.	Restrictions on the ability to stack revenues from ancillary services alongside CM.	Allow stacking of revenues between the CM and ancillary services. Review exclusivity clauses.
14.	Aggregators can't change the portfolio of DSR participants which make up a CM unit. Therefore, if one participant withdraws the whole contract is nullified.	Enable asset reallocation by DSR providers.

15.	By determining a strict reliability standard in advance this can lead to over-contracting of capacity, thereby limiting the scope for ancillary services (Reserve) to provide peak demand.	Reduce reliability standard and / or allow flexibility to provide real-time balancing.
16.	The CM is keeping old plant in operation which will prove direct competition for local assets.	BEIS / Ofgem need to consider what types of generation they are trying to encourage. With many contracts being awarded to existing fossil fueled plants they are prolonging the life of these generators to the detriment of flexibility providers. The CM Rules need to be amended to discourage this.
17.	The recent falling clearing prices of CM contracts (2018 auctions) is proving unattractive for storage providers.	As above – review CM Rules regarding old 'dirty' plant.
18.	By relying on the CM to manage future perceived problems it stifles investment and development of other low carbon solutions to the problem such as DSR, storage and demand reduction.	As above – review CM Rules regarding old 'dirty' plant.
	NETWORKS	
19.	There is no set timescale for DNOs to transition to becoming DSOs. Not all DNOs appear to want to change or feel the need to change their operations.	WPD are actively working towards transition to DSO status. WPD have committed to establishing their DSO role by the end of ED-1 (2023) but this is not the case for all DNOs. And indeed, WPDs position is to be 'market ready' by 2023, anticipating that most of the DSO functions will come online during RIIO-2 (2023-2031). WPD will undertake an over-arching 'DSO Transition Programme' to lead this work. BEIS / Ofgem should set a timescale for all DNOs to commit to.
20.	Ambiguities as set out in the Open Networks Project about who should lead and coordinate on procurement of balancing services in future as distributed generation grows.	WPD would prefer to move to one of the DSO-led models identified in the Open Networks Project (Table 4), presumably Option 4 or 6 as they claim the DSO-led models 'will result in the most efficient whole system outcome'. Either of those options should be beneficial to LEMs as these both have a wide role for the operation of DER. There may

		be market conflicts though in Option 6 with the role of the DSO as a commercial aggregator, which need to be assessed. WPD recognise that data sharing with the TSO will be critical to optimising the network.
21.	DNOs currently only have limited visibility down to 33kV asset level with no visibility below this. They also have no real understanding of the amount of DER operational on the network at the street / household level.	WPD have signaled that they will primarily deploy supporting infrastructure on the EHV network down to the 33kV asset level before increasing visibility at LV levels. UoE have responded to WPD that they don't agree with this stance as DER and DSR will continue to develop across all levels of the network. Even if it is not realistic to upgrade the whole network at the moment then it would make sense to take one part of the network (like Cornwall with current high constraints) and upgrade the visibility and control across all voltage levels early on in the DSO process to provide some vital learning for later stages of the transformation (Bray *et al.*, 2017).
22.	Enhanced sensing with active technical and commercial mechanisms is required.	WPD will develop a platform (Project EFFS) to provide visibility, warn of critical peak price periods and take offers of DSR service.
23.	There is uncertainty over how many services the DSOs will be procuring from distribution markets and how many services they can operate themselves.	WPD have indicated that these are likely to be reserve services for real power and voltage control (such as Flexible Power) rather than fast acting products such as frequency response. WPD have signaled that secondary trading markets such as the P2P market may be created for DER providers. WPD have stated that they will use a mixture of tenders and market based arrangements for procurement of services. However, there is still uncertainty over how much flexibility WPD will procure at this stage.
24.	DSOs should be encouraged to seek NWAs where this can be achieved at lower cost than reinforcement. RIIO helps in this effect, with a shift to RAV from totex rather than capex.	More acknowledgement needed of the value of network savings that could be achieved through deferment of network upgrades and potential recompense to those providing these NWA solutions. WPD have signaled that they **will** seek NWA from DSR and flexibility providers where issues can be solved for a lower total cost than reinforcing the network.

		Decisions will be taken in 'investment decision timescales' to reduce, defer or negate conventional build. These timescales will presumably correspond to RIIO timescales. DNOs should include in their Business Plans how they will include NWAs and the types of suitable projects which will be considered along with timescales for implementation.
25.	Alternative connections such as ANM, Timed, Soft-Intertrip and Export Limited in CMZ are enabling more connections to be made to the network, but these come with penalties (such as LIFO) which undermine the operational capacity and financial viability of DER. WPD are extending these products to all WPD areas and will include demand and storage connections.	One solution used by DNOs is active network management (ANM) in Constraint Managed Zones (CMZ) which allows a new generator to connect within the zone for a quicker connection with a lower connection fee, in exchange for the DNO being able to curtail generation at times of system stress. This is a financially competitive solution for the DNOs as they still receive a connection fee and they can avoid network reinforcement costs by curtailing generation instead of upgrading the network. However, it incurs financial risk and uncertainty to the generator as the DNOs can curtail generation themselves, rather than procure market solutions for flexibility, thus undermining the value in market-based flexibility services. Curtailment also often means that it is the renewable generation which is turned off first in the LIFO queue, undermining national targets and causing higher power prices. Therefore ANM is not a good long-term solution to achieving a smart and flexible energy market at the distribution level. The issue of connections is being raised through the Charging Futures work (see Section 5) which could either have a positive or negative effect on future connection arrangements depending on the model chosen. In addition, WPD have committed to creating a localised visibility platform (which will be publicly available) to demonstrate where there is congestion / capacity on the network.
26.	Stacking of revenues needed across DSO services and ancillary services to ensure viability.	WPD have signaled that they will be open to stacking of services in order to allow customers to participate in transmission and distribution level markets.
27.	RIIO still gives network operators the ability to 'game' the system in setting their revenues and innovation projects have to date been seen as add-ons rather than BAU.	The move to totex is welcomed but innovative solutions need to be seen as business as usual, not interesting add-ons with no long-term benefits to customers. RIIO-2 should therefore provide price controls which encourage active participation in the DSO transition and seek flexible solutions to network management. Clarification

		needs to be made as to whether the DSO transition costs will come out of RIIO-2 revenues (and therefore paid for by customers through network charging) or whether there should be a separate pot to fund this. The way in which the networks set their revenues has a huge implication on network charging as discussed in Section 5 which will have an impact on consumer behaviour.
28.	WPD acknowledge that stronger locational signals for distribution network charges will have an effect on the siting of additional DER providers.	Network charges are currently being reviewed through the Charging Futures work being undertaken by Ofgem (see Section 5).
29.	Ambiguities over whether DNOS should own / operate storage – which would be uncompetitive to flexibility providers.	Ofgem signaled that DNOs shouldn't own / operate storage as it is uncompetitive to the market. UKPN and Northern Powergrid however have argued against this. WPDs position is that storage owned / operated by DNOs should only be used as a 'last resort' if the market fails to deliver.
	NETWORK CHARGING	
30.	Targeted Charging Review – residual charges Any changes to the existing charging regime will have a potential impact on how prosumers will use the network in future. Whilst it may be sensible to make these customers pay a fair charge for their ability to rely on the network this should be done in a way which still incentivises prosumers for their positive actions.	BEIS / Ofgem need to need to consider what type of customer behaviour they are wanting to incentivise / disincentivise through adopting any new methodology. Currently only the ex-ante and ex-post capacity demand charges option reward prosumers for their behaviour. Keep a watching brief on developments on this in 2018 and engage in consultation events.
31.	Forward looking charges and access rights Details are very sketchy at the moment but could have widespread implications for connections.	Keep a watching brief on developments on this in 2018 and engage in consultation events.
32.	Embedded Benefits – the slashing of EB will have a major negative effect on the revenue of small scale generators.	This retrograde decision has already been made and will implemented from April 2018, despite Ofgem facing a judicial review in January 2018.

	DSR	
33.	Access to ancillary services.	Rationalisation of services to simplify process and align timescales for tendering. National Grid will also trial auctions from late 2018.
34.	Restrictions on the ability to stack revenues from ancillary services alongside CM.	Allow stacking of revenues between the CM and ancillary services. Review exclusivity clauses.
35.	Access to Balancing Market.	Provide for participation from independent aggregators.
36.	Baselining & settlement.	Clarify the role of aggregators in regard to relationship with suppliers / set a code of conduct. Should aggregators be balancing responsible parties i.e. exposed to imbalance pricing?
37.	Aggregators can't change the portfolio of DSR participants which make up a CM unit. Therefore, if one participant withdraws the whole contract is nullified.	Enable asset reallocation by DSR providers.
38.	Technical issues.	Simplify metering requirements. Improve forward-looking signals for network usage to encourage price flexibility related DSR.
39.	Structure of network charges.	Being reviewed through the Embedded Benefits Review / TCR / forward looking charges review.
40.	Limited awareness of DSR & financial benefits of DSR.	Power Responsive project launched by National Grid to raise awareness and engage with businesses.
41.	Limited access to DSR market for domestic and smaller non-domestic customers due mainly to smart meter rollout not being complete.	Smart meter rollout should be complete by 2020.
42.	Limited availability of smart tariffs, smart appliances.	Half hourly settlement – introduce mandatory HHS for domestic and smaller non-domestic customers. Encourage smart tariffs.

		Set standards for smart appliances. Domestic energy storage. EV charge points & Vehicle to Grid technologies.
43.	Cyber security.	Study commissioned to assess magnitude of cyber security risk up to 2030.
	AGGREGATORS	
44.	No legally defined role for independent aggregators.	To enable independent aggregators to enter the market at scale, it is critical that their role and responsibilities are clarified. In particular, it is important that the relationships between suppliers, balancing responsible parties (BRPs), and independent aggregators are clear, fair, and allow for fair competition (SEDC, 2017).
45.	Balancing Mechanism – no current route to access BM.	Create a new route for independent aggregators to access the BM. Will need code modifications.
46.	Capacity Market - Aggregators can't change the portfolio of DSR participants which make up a CM unit. Therefore, if one participant withdraws the whole contract is nullified.	Simplify metering requirements. Stack revenue streams across markets. Enable asset reallocation.
47.	Other markets.	Ensure a level playing field for access to additional energy markets where aggregators can be accommodated efficiently. Improve signals for network usage.
48.	Measurement - Potential for gaming.	Measure DSR volumes and ensure that baseline gaming opportunities are mitigated.
49.	Cost reflective pricing.	Allow for payments to cover the cost of energy sold on by the aggregator, which was initially sourced by the supplier to help ensure a more cost-reflective supply curve at a system level and a level playing field between different technologies.
50.	Balancing responsibility and delivery risk.	Both balancing costs and delivery risks should be borne by the parties that created them.

	STORAGE	
51.	Limited understanding of the complexity surrounding the need for both import and export capacity, and the differing uses, sizes and locations of connections can result in lengthy and expensive connections.	Ofgem will work with industry and DNOs to improve the connection process, for example by introducing flexible connections which will be cheaper and quicker. However, flexible connections (i.e. ANM) can have a detrimental financial impact on distribution connected storage in that batteries could be prevented from discharging at optimal times due to DNO contractual limitations.
52.	Distribution connected storage currently pays both import and export network charges as it 'uses the network for both'.	The Targeted Charging Review (Ofgem, 2017o) considers the current system of network residual charges to ensure storage doesn't pay the 'demand residual' element of network charges at T & D level.
53.	Different definitions of storage are used for different regulatory purposes, including licensing and the capacity market. Need to develop a common definition for use across different policy areas.	Ofgem consulted on the regulatory framework for electricity storage in Sept 17 (Ofgem, 2017a) and affirmed that the Electricity Act 1989 will be amended to include a definition of storage as a distinct subset of the generation asset class. Storage is also being defined in the Grid Code (GC096).
54.	Several levy costs are applied twice to storage (once on charging and once on supply), including the costs of the Renewables Obligation, Feed-in Tariff, Capacity Market and the Climate Change Levy. This results in double counting of supply to the consumer on the same electricity.	Storage should be exempted from final consumption levies. Ofgem are therefore proposing a new licence condition 'Condition E1' to provide clarity that 'The licensee shall not have self-consumption as the primary function when operating its storage facility' (Ofgem, 2017a) to overcome the double counting issue.
55.	As storage is yet to be classified or defined, it is unclear how storage fits within the planning framework. Storage is currently defined in planning as an 'electricity generating station' causing uncertainties over whether it should be in national guidance or dealt with at the local planning level.	A review of planning legislation will assess whether guidance can be simplified i.e. by including a national planning threshold for storage and associated planning guidance. However, there is no timescale set for amending this.
56.	Lack of clarity how storage might interact with renewable installations receiving support under the RO, CFD or FIT regimes	Ofgem produced Draft Guidance Dec 17 (Ofgem, 2017b) to provide clarity on when storage can co-locate alongside renewable generation without risking agreements. Ofgem consider that where the scheme requirements are being

		met, storage can be deployed without risk to accreditation, although decisions would be made on a case-by-case basis.
57.	The EU 'Winter Package' states that DSOs should not be allowed to own, develop, manage or operate storage in order to promote market competition.	BEIS & Ofgem announced that DNOs should not own or operate storage to allow market competition. This should be beneficial to the LEM but some DNO's have argued against this.
	P2P TRADING	
58.	Customers cannot trade electricity between themselves without a TPLS. The supplier undertakes all the supplier obligations - mitigating the imbalance risk, paying use of system charges etc. In addition, customers can only have one licensed supplier per property. However, if customers were able to have more than one supplier this would in turn raise issues regarding the balance of power, which supplier would be responsible for balancing obligations, security obligations and environmental policy obligations etc.	'Future supply market arrangements – call for evidence' launched in November 2017. Initial way forward expected Spring 2018. Regulatory Sandbox trials commencing in conjunction with Ofgem to assess barriers.
59.	Billing and settlement also has to be through one licensed supplier – which could potentially lead to double counting if issue not addressed.	As above.
60.	Unknown whether SMETS2 meters would be able to handle more than one supplier per meter point. Smart meter rollout is not anticipated to be finalised until 2020. HH settlement is currently an option for domestic and small business customers but is not as yet mandatory. Issues with accessing smart meter data – DNOs and P2P platform providers cannot see customers smart meter data due to data protection issues.	Need sophisticated metering to determine what volume is being sold P2P. HH settlement would be needed in order to participate. Resolution needed on who can access smart meter data.
61.	DNOs currently only have limited visibility down to 33kV asset level with no visibility below this. They also have no real understanding of the amount of DER	Granular data and sophisticated IT solutions are required at the DNO level. WPD have signaled that they anticipate this

	operational on the network at the street / household level. A more granular level of detail will be needed in order to establish what is happening at the customer / connection level.	to be in place (for their own network areas) by the end of RIIO-1 (2023). This data should be publicly accessible in order to facilitate P2P exchanges. BEIS & Ofgem should provide regulatory clarity over data – in particular encourage data sharing between the SO, DNOs and suppliers at the lowest possible granularity. This can include data regarding network constraints and the availability of DER on the network.
62.	Blockchain is being hailed as a revolutionary mechanism for trading energy but the blockchain process itself is hugely energy resourceful (Proof of Work – quantum computer cracking cryptography) or determined by those with the most financial claim (Proof of Stake) and transactions are not financially regulated.	Ofgem are considering questions around security, customer acceptance, dispute resolution and underwriting in blockchain scenarios.
63.	Reduced DUoS charges are not currently available without a derogation.	All of network charging will be reviewed through the Charging Futures work on residual and forward-looking charges. Current thoughts at Ofgem are that network charges should be fair for all users and so there could potentially be a charge per transaction on all P2P trading.
64.	Unknown how P2P will affect FiT payments – if export tariff has to be forfeited this reduces profitability.	FiT export tariffs currently based on 50% of generation total – and paid by the supplier. Customers could either forfeit export payments or sophisticated metering could establish what has actually been purchased elsewhere.
65.	It is not easy to see a financial benefit to P2P trading due to the above issues and if customers can receive higher payments from alternative markets they will probably seek those first.	Although there appears to be little financial reward at present due to regulatory issues more profit could be realised through reduced network charges and the removal of trading through a TPLS. There could also be a more profitable solution in demand generation coupling i.e. if a generator could offer DTU to a local business in order to overcome curtailment this could lead to a cheaper electricity deal for the business whilst the generator could export when they would otherwise have been curtailed.
66.	Domestic customers may like the idea of being able to trade with their local	P2P platforms should offer automated solutions for domestic customers who would prefer this.

	community but they may require a high level of automation in order to participate. For example, the Wadebridge Sunshine Tariff ToU trial saw more demand shifting when processes were automated (Regen, 2017).	
	LOCATIONAL MARGINAL PRICING	
67.	It is likely that Ofgem will consider LMP to be discriminatory, as customers in one location would pay higher wholesale prices than customers living elsewhere on the network; thus making LMP politically infeasible. Ofgem are not considering LMP during the current network charging reform.	In Ofgem's role as regulator they will want to evaluate whether LMP is discriminatory to customers. However they may wish to consider whether there is a different case to be made for I&C customers rather than domestic customers.
68.	Distribution level LMP is not used in any international energy market.	LMP is completely untried at the distribution level.
69.	LMP is not suited to the self-dispatch wholesale market model.	LMP is better suited to power markets with central dispatch, where LMP can achieve a more efficient dispatch to avoid congestion. However in self-dispatch power markets, with liquidity of pricing, LMP isn't a consideration at present and its effectiveness has been questioned (Singh *et al.*, 1998). In GB, arguments have been made for balancing charges to be nodal, so that generators face the right prices for marginal output decisions (Newbery *et al.*, 2017).
70.	Data Gap - this model requires the DNO to have data on the real-time power flow on the network and an understanding of what's happening both behind and in front of any network constraint.	This data is not at present available although WPD have set out timescales within their DSO Transition Programme for delivering new data and IT products. These are expected to be delivered by the end of ED-1 in line with WPDs stance of being 'market ready' by 2023.
71.	Data sharing.	Once these data systems are available at the DNO level clarification will be needed regarding data sharing between the DNO and third parties.

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10. ACRONYMS

ANM	active network management
BAU	business as usual
BETTA	British Electricity Trading and Transmission Arrangements
Big 6	British Gas, EDF Energy, npower, E.ON UK, Scottish Power & SSE
BM	Balancing Market
BMUs	Balancing Mechanism Units
BRP	balancing responsible party
BSC	Balancing and Settlement Code
BSUoS	Balancing System use of System (charge)
BTM	behind the meter
CfD	contract for difference
CfE	Call for Evidence
CHP	combined heat and power
CM	Capacity Market
CMZ	constraint managed zone
CUSC	Charging and Use of Services Code
CVA	central volume allocation
DCUSA	Distribution Charging and Use of Services Agreement
DER	distributed energy resources
DNO	Distribution Network Operator
DSO	Distribution Service Operator
DSP	Distribution Service Providers (New York model)
DSR	demand side response
DTU	demand turn up
DUoS	Distribution Use of Service (charges)

EB	embedded benefits
EFR	enhanced frequency response
EG	embedded generators
EHV	extra high voltage
ENA	Energy Networks Association
EPG	Energy Policy Group at the University of Exeter
FFR	firm frequency response
FiT	feed-in tariff
GB	Great Britain
GSP	grid supply point
GW	gigawatt
HHS	half hourly settlement
IGov	Innovation and Governance Team, Energy Policy Group, UoE
kV	kilovolt
kW	kilowatt
kWh	kilowatt hour
LCT	low carbon technologies
LEM	local energy market
LMP	locational marginal pricing
LV	low voltage
MW	megawatt
NG	National Grid
NIA	network innovation allowance
NIC	network innovation competition
NWA	non-wire alternative
NY REV	New York State's Reforming the Energy Vision
Ofgem	Office of Gas and Electricity Markets
P2P	Peer-to-Peer (trading)

PPA	Power Purchase Agreement
RAV	Regulatory Asset Value (networks)
RES	renewable energy systems
RIIO	Regulation = Incentives + Innovation + Outputs
RO	renewables obligation
SEC	Smart Energy Code
SCR	settlement code review
SME	small and medium sized enterprises
SMETS1	smart metering equipment technical specifications: first version
SMETS2	smart metering equipment technical specifications: second version
SO	System Operator
STOR	Short-term Operating Reserve
SVA	supplier volume allocation
TERRE	Trans European Replacement Reserves Exchange
TNUoS	Transmission Network Use of Service (charges)
ToU	time of use (tariff)
TPLS	third party licensed supplier
TSO	Transmission System Operator (National Grid)
UoE	University of Exeter
UK	United Kingdom
UKPN	UK Power Networks (DNO)
WPD	Western Power Distribution (DNO)