Network Innovation Allowance (NIA) study: A market-based approach to delivering efficient network constraint management

CLIENT: UK Power Networks

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Executive Summary

Conventional connection of distributed generation

The conventional approach to new connections on the distribution network begins with a customer requesting a connection at a particular point on the network for a given capacity. The Distribution Network Operator (DNO) then determines the work required to accommodate that new capacity, and makes a connection offer on that basis. If the connecting customer accepts that offer, the work will be carried out, and the customer will pay for a significant proportion of the costs incurred. In turn, provided the network is operating normally, they will gain access to the network up to the agreed capacity at all times in the future.

In recent years, there has been a significant rise in distributed generation (DG) in Great Britain. As a result, the prevalence of export constraints on the distribution network has increased, meaning that additional exporting Distributed Energy Resources, such as DG and batteries, cannot be connected without first reinforcing the distribution network. The reinforcement may only be required to cover periods of high generation and low demand that could only occur for a few hours each year. The delay and cost associated with these reinforcement works can in some cases be prohibitive for new DER.

Flexible Connections

As an alternative to reinforcing the network the concept of Flexible Connections has been developed and implemented by a number of DNOs. This allows DG to avoid some of the reinforcement costs by instead accepting a degree of curtailment during periods of network constraints. 'Principles of access' define under what circumstances they can export onto the distribution network – typically a function of the size of the constraint, the number of other Constrained DER (CDER) in the area, and the relative priority that each DER is given.

The primary limitation of the principles of access adopted to date is that the priority is not given to DER that can be curtailed at least cost, nor the DER that is best placed to alleviate the constraint. Instead, curtailment has either been shared uniformly between DER ('pro rata') or based on the order in which DER connected ('Last In First Off'). Another important limitation of these approaches is that they have tended to be limited to DG, and do not easily enable other DER to participate. There may be pre-existing DG that are better placed to alleviate a constraint, or new technologies (e.g. batteries) or services (e.g. Demand Side Response) that can avoid the need to curtail altogether. The final key limitation is that existing approaches provide little indication of whether and when a network should be reinforced to alleviate a constraint, and provides no mechanism to fund any eventual reinforcement.

Market-based Flexible Connections

This paper explores the use of market-based Flexible Connections. These can take a number of forms, including:

- **Auctioning and trading capacity rights:** instead of allocating network capacity to DER through their connection agreement, available capacity is auctioned. Successful bidder secure access to the network for a given period of time, or can trade their capacity rights to other participants;
- **Local energy trading:** A localised constraint creates a local energy market, which allows a generator that otherwise be curtailed under a Flexible Connection to increase its output by trading its energy directly with a local consumer;
- **Traded curtailment obligations:** Where a network is constrained, CDER are given Flexible Connections as per existing arrangements. A Local Flexibility Market (LFM) then allows them to trade their curtailment obligations with each other, or to other participants on the local network.

This report focuses on traded curtailment obligations, but the approaches described and the issues identified can be read across into both local energy trading and the auctioning and trading of capacity rights.

Under the approach explored in this report, CDER trade their curtailment obligations with each other and with FDERs connected to the same part of the network. This enables DER for whom exporting onto the grid is more valuable (e.g. those with high subsidies or those providing high-value system services) to reduce or avoid curtailment. They can do this by transferring the curtailment obligation (along with an agreed fee) to a DER that places a lower value on grid access, or allowing a DER such as a battery or DSR site to consume the excess energy locally, effectively providing them with reduced energy costs.

In meshed (i.e. non-radial) networks, the extent to which a DER can alleviate a given constraint can vary considerably. Some DER may be close to the constraint, in which case a 1MW change in DER export may translate into 1MW of constraint alleviation. However, others can be much further from a constraint, with most of their power being exported via a different route, meaning that a 1MW change at the DER may only result in, say, a 0.2MW change at the constraint.

Market-based Flexible Connections can be designed to account for this 'sensitivity', meaning that all other things being equal more sensitive DER will tend to be curtailed before less sensitive DER. As a result, the overall level of curtailment required to alleviate a constraint can be significantly reduced (against conventional principles of access). This reduces the overall cost of constraint management, but also tends to result in higher utilisation of low-carbon sources of generation. This in turn should lead to the connection of more flexible resources more cheaply and quickly, whilst avoiding unnecessary reinforcement, ultimately leading to cost savings for end consumers.

This report outlines two such market-based arrangements, both of which are based on variants of a LFM through which DER, with both firm and flexible connections, can make 'curtailment offers'. Alternatives to curtailment, such as demand side response providers and battery storage, are encouraged to make similar offers where they can relieve the constraint more efficiently. The LFM adjusts these offers to take into account each DER's sensitivity to the constraint in order to produce an 'effective offer' stack, which defines an efficient order of curtailment. In order to alleviate a constraint, the DNO (or its Active Network Management system) will curtail the DER by stack order (from lowest- to highest- effective offer price).

The key difference between the arrangements for trading curtailment obligations explored in this report concerns the way in which curtailment offers are funded:

1. Under the first approach, the offer prices are met by using a fund shared amongst the CDER behind the constraint. The CDER are obliged to pay into the fund to ensure that curtailment offers can be met.
2. Under the second approach, in parallel with the curtailment offers being made by all participating DER, curtailment bids are made by CDER (indicating their willingness to pay to avoid curtailment). Offers and prices are matched either until the constraint is alleviated or until the offers exceed the bids (in which case the remaining constraint is managed using the default principles of access).

One advantage of a market based constraint management is it provides the DNO with an indication of the total cost of curtailment faced by CDER. When the total cost of curtailment is less than the annuitised cost of reinforcement, this indicates that reinforcement is a lower-cost strategy for managing the local constraint. This can therefore be used as a trigger for the DNO to propose a reinforcement option to the CDER. In addition, the costs that CDER face to fund the local constraint curtailment each year could be used as the basis for sharing the cost of reinforcement, presenting a fair way of apportioning costs. Under existing non-market-based arrangements, the incentives for reinforcement can vary considerably amongst CDER.

This report presents a number of options for the specific design of the LFM. Where appropriate, recommendations for the best option are made. These options require refinement through further engagement with the regulator, other DNOs, and DER customers, before a final decision is made. Further work is required to establish the benefits of each option. A Cost Benefit Analysis will be carried out to inform the business case for the DNO and other network stakeholders. This would then be followed by trials of the preferred approach.

Contents

Figures

Tables

1 Introduction

1.1 Background

The conventional approach to new connections on the distribution network begins with a customer requesting a connection at a particular point on the network for a given capacity. The Distribution Network Operator (DNO) then determines the work required to accommodate that new capacity, and makes a connection offer on that basis. If the connecting customer accepts that offer, the work will be carried out, and the customer will pay for a significant proportion of the costs incurred[1]. In turn, provided the network is operating normally, they will gain access to the network up to the agreed capacity at all times in the future.

In recent years, there has been a significant rise in distributed generation (DG) in Great Britain. As a result, the prevalence of export constraints on the distribution network has increased, meaning that additional DG and storage requiring the option to export to the network cannot be connected without first reinforcing the distribution network. The reinforcement may only be required to cover periods of high generation and low demand that could only occur for a few hours each year. The delay and cost associated with these reinforcement works can in some cases be prohibitive for new DER, and has been a barrier to deployment of more renewables and flexible storage.

As an alternative to reinforcing the network to accommodate these infrequent constraints, the concept of Flexible Connections has been developed and implemented by a number of DNOs[2].

Comparing Transmission and Distribution connections

National Grid Electricity Transmission (NGET), in its role as the GB System Operator (GBSO), commonly manages transmission level constraints by procuring generation curtailment or Demand Side Response (DSR) services. The GBSO is able to recover the cost of these constraint management services by socialising the costs amongst transmission system customers through balancing services use of service (BSUoS) charges. BSUoS charges recover the cost of day to day operation of the transmission system, and are calculated as a flat tariff across all users.

When a customer requests a connection to the transmission system, the GBSO takes a 'connect and manage' approach to their connection. Under this approach the connecting customer is not responsible for any network works required to accommodate them, beyond their own connection to main grid. If a connection would result in a constraint, the GBSO can either action the required reinforcement or the constraint can be managed through constraint management services.

By contrast, on the distribution network, connecting customers are responsible for the impact their connection may have on the wider network, up to two voltage levels above their connection point. Therefore, connections to constrained parts of the distribution network can require costly network reinforcements needed to relieve the constraint.

[1] "Generally the connecting customer will only pay for reinforcement at the voltage level it is connecting to and one voltage level above" Ofgem (2014) *A guide to electricity distribution connections policy*
[2] See, for example, UK Power Networks' Flexible Plug and Play project, or SSEN's Orkney Smart Grid

1.2 Existing approaches to Flexible Connections

Under Flexible Connections, exporting DER can avoid some of the reinforcement costs that would be associated with an unconstrained connection, but instead have to accept a degree of curtailment during periods in which the network is constrained. Connecting DER may be provided with forecasts of constrained periods, but there is inherent uncertainty as to the timing and frequency of such events. The subsequent connection of additional exporting DER or a decrease in local demand will typically increase the likelihood and magnitude of export constraints, whereas an export reduction or a demand increase will tend to alleviate such constraints.

When a constraint occurs, it is not typically necessary to curtail all Constrained DER[3] (CDER) to the maximum extent. The rules by which curtailment is applied has a significant impact on the curtailment risk that each CDER faces. To date, these rules, or 'principles of access' have tended to take one of two forms:

- **Last In First Off (LIFO):** during periods of network constraint, curtailment is applied in reverse order of connection, thereby minimising the risk for those developers connecting early;
- **Pro-rata:** curtailment is shared by all those participating within the scheme, with new connections therefore increasing the expected level of curtailment for all parties, usually with a cap imposed on the total volume of flexible connections allowed in a particular actively managed zone in order to limit the risk for existing generators.

Such schemes, as they have been enacted to date, have tended to have three key limitations:

1. **Inefficient curtailment:** By opting either to curtail in order of connection or by sharing curtailment evenly across parties, these schemes do not deliver the least-cost approach (for the system as a whole) to managing a given constraint. Revenue streams differ between CDER due to varying offtaker terms and system services being provided, subsidy levels, and variable operating costs. This means that there is a range of opportunity costs of curtailment across CDER units. Furthermore, on meshed networks, some units are much better placed to alleviate a constraint than others. Taking account of these differentials could enable the management of network constraints at a significantly lower overall cost.
2. **Failure to accommodate alternatives to curtailment:** It can be significantly cheaper to manage an export constraint by increasing demand rather than reducing generation. Demand Side Response[4] (DSR) and storage can both be used to increase local demand in this way. Some Flexible Connection schemes (e.g. Orkney Energy Storage Park) have explored the use of battery-based constraint management contracts, but have not allowed batteries to participate directly under the flexible connection arrangements.
3. **No triggering and funding of future reinforcement:** If a network continues to receive requests for new connections, or if the curtailment faced by existing CDER escalates for whatever reason, it may be economically efficient eventually to trigger reinforcement. LIFO

[3] The term Constrained DER refers to any resource that requires an export connection (e.g. DG and storage) but that has accepted some curtailment obligation under a Flexible Connection agreement

[4] This refers to a change in a customer's electricity consumption in response to a signal from a supplier, network operator, system operator or some other network actor, in order to provide system or network services.

and pro rata schemes limit the escalation of curtailment, but do not provide a clear trigger for instigating reinforcement. Furthermore, the schemes adopted to date do not include a mechanism for recovering the costs that would be associated with that reinforcement, and the incentive to fund reinforcement can vary by participant, particularly under LIFO (since the earlier connectees who experience limited curtailment will see little value from the reinforcement).

1.3 Potential for more efficient curtailment

This paper explores the use of market-based Flexible Connections. These can take a number of forms, including:

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Market-based Flexible Connections can be designed to account for this ‘sensitivity’, meaning that all other things being equal more sensitive DER will tend to be curtailed before less sensitive DER. As a result, the overall level of curtailment required to alleviate a constraint can be significantly reduced (against conventional principles of access). This reduces the overall cost of constraint management, but also tends to result in higher utilisation of low-carbon sources of generation.

The use of market-based approaches should have the potential to reduce substantially the cost of constraint management, and the level of curtailment needed to manage distribution constraints. This in turn should lead to the connection of more flexible resources more cheaply and quickly, whilst avoiding unnecessary reinforcement, ultimately leading to cost savings for end consumers.[5]

[5] Whilst DER developers would be the direct beneficiary of more efficient curtailment, end consumers should benefit in two ways. First, the costs of connection-related reinforcement more than two voltage levels above the point of connection are socialised. So to the extent that market-based Flexible Connections reduce the need for conventional reinforcement, this should reduce consumer bills. Second, it can be expected that a reduced connection cost will make developers of new assets more competitive in the Capacity Market, Balancing Services tenders, and/or in auctions for low carbon electricity generation.

2 Market Design

2.1 Market design principles

The market-based constraint management approach described in this report is designed to take into account the cost a DER incurs when it is curtailed, and its effectiveness ("sensitivity") in alleviating a constraint. The intention of this study is to develop the design of a Local Flexibility Market (LFM) that would:

- Allocate curtailment efficiently amongst CDERs
- Provide an economic signal to DERs that can provide alternatives to curtailing generation (e.g. batteries and demand side response);
- Provide a signal as to how much revenue is forgone via curtailment, and therefore indicate when network reinforcement is preferable to continuing curtailment.

There are numerous possible market designs that would meet these criteria. In order to evaluate the options, we have followed some **key principles**:

1. **Cost borne by beneficiaries** – Ultimately, the cost of curtailment needs to be borne by those DERs opting for flexible connections, rather than being socialised across the wider DNO customer base (although this might change in the future);
2. **Technology agnostic** – Where possible, the market design should be technology agnostic, opening the market to alternatives to curtailment, thereby increasing competition and driving technical and economic efficiency;
3. **Improvement for participants** – The market design needs to present an opportunity for all potential market participants to improve their situation relative to the non-market-based connection agreement, particularly if market participation is voluntary;
4. **Efficient Curtailment** – The market should incentivise the participation of low-cost and optimally-sited generators allowing constraints to be relieved in the most efficient manner;
5. **Fair** – It should discourage behaviour that would be seen as "gaming" the system, particularly if it results in some network users paying more than they would under current arrangements.

2.2 Approach overview

2.2.1 Curtailment offers

The fundamental principle being proposed in this report is that, instead of using mechanistic principles of access (e.g. pro rata or LIFO), curtailment is carried out based on curtailment offers[6]

[6] For the purpose of this report, we treat the LFM as a curtailment market, rather than an energy market. As such, participants "offer" to curtail, meaning that they will reduce their output for a price. Correspondingly, participants "bid" for curtailment, meaning that they will pay to be able to increase their output against a curtailment baseline.

made by local participating DERs. All CDER would post these curtailment offers but, in addition, any Flexible DER (FDER) that is able to alleviate a constraint can also participate.[7]

In order to alleviate a constraint, the DNO curtails (or applies demand turn-up) to those participating DERs posting offers with the lowest price (after accounting for sensitivity), only using higher-priced offers as required. This means that the overall curtailment cost is typically lower than it would have been under pro rata or LIFO arrangements.

One significant advantage of the LFM is that it allows any DER that is able to adjust its output (or consumption) to participate. This widens the pool of flexibility providers, typically resulting in lower-cost or reduced curtailment. Whilst the approach to making offers will differ by technology, by location and by time of day, it may be useful to consider some of the factors that will inform a DER's curtailment offer:

- Renewable DG, such as wind and solar, would lose the wholesale price, subsidy and embedded benefits that would otherwise have been paid via their offtaker, so would be expected to post relatively large offers.
- Thermal DG, such as CHP and diesel, would similarly lose their offtaker payment (which would be lower than for renewables if the subsidy was lower or nil) but would also avoid fuel (and carbon) costs, so their offer would likely be lower than for wind and solar.
- Battery offers would depend on whether the battery is simultaneously participating in other markets:
    - If a battery were sitting idle, waiting for a low-price period to charge, it could post a low offer indicating its willingness to charge to alleviate the distribution constraint;
    - If it were exporting to perform energy arbitrage (extracting value from the daily spread in wholesale prices) it might wish to post a higher offer to reflect the reduction in value captured from the wholesale market;
    - In periods where it was providing high-value exports (e.g. providing balancing services to the System Operator), it could post very high offers to reflect the lost revenue or penalties that it would incur if it were curtailed.[8]
- DSR providers will need to consider the cost of consuming additional energy. Offers will vary depending on the nature of the load, reflecting, for example, the cost of running a cooling system more intensively than the dwelling or commercial process requires, or producing more of an electricity-intensive product than would otherwise have been optimal. Some DSR provision may actually come from DG (or batteries) behind the meter. As with batteries, a DSR's offer may also be affected by its participation in other flexibility markets.

[7] For the purpose of this report, 'Constrained DER' (CDER) refers to DER with curtailment obligations under Flexible Connections, 'Flexible DER' (FDER) refers exclusively to those DER that choose to post curtailment offers, and 'participating DER' or simply 'DER' includes both CDER and FDER.

[8] Note that rules surrounding participation in some SO services may preclude a battery from simultaneously participating in a constraint management service, or indeed from accepting a Flexible Connection. The market-based solutions described in this report do not resolve the issue of service conflicts, but may provide a mechanism by which the risk of conflicts is reduced.

The creation of the offer stack is an effective approach to managing constraints in the least-cost way. It enables the reduction in curtailment of high-value (and often low-carbon) exports in favour of cheaper forms of curtailment, allows novel technologies and service providers to participate, and increases the overall level of competition for providing that curtailment.

2.2.2 Funding curtailment offer payments

One key issue associated with market-based constraint management is the funding of those curtailment offers. Under current arrangements, CDER accept curtailment when network constraints are active in return for avoiding the most of the cost of network reinforcement. These customers are therefore the main beneficiary if constraint management can be achieved more efficiently.

We assume, therefore, that these CDER should fund the LFM, rather than it being socialised across all network customers. We do not rule out the possibility, however, that this changes in the future, perhaps to bring it in line with the "connect and manage" rules on the transmission network, under which the cost of connection-related reinforcement is passed to the wider consumer rather than the connecting party.

We consider two main mechanisms of apportioning the cost of local curtailment services:

1. Under the first approach, the participating DER offer prices are met by using a fund shared amongst the CDER behind the constraint.[9] The CDER are obliged to pay into the fund to ensure that curtailment offers can be met.
2. Under the second approach, in parallel with the curtailment offers being made by participating DER, curtailment bids (indicating their willingness to pay to avoid curtailment) are made only by CDER. Offers and prices are matched either until the constraint is alleviated or until the offers exceed the bids (in which case the remaining constraint is managed using the default principles of access).

These two approaches are discussed in the following section.

2.3 Approach 1: DER offers funded by FDG customers

2.3.1 Overview

Under this approach, participating DERs post curtailment offers, which the DNO converts into 'effective offers' to account for the sensitivity of the DER to the constraint. This forms the basis of an 'effective offer' stack, which the DNO uses to determine the order of curtailment to be applied when the constraint is binding, and to determine the level of payment made to each DER.

The participating DER are paid out of a fund, to which CDER must contribute. Whilst the fund must be large enough to cover the curtailment offer payments, the relative contribution required from each CDER can be calculated in a number of ways. This may depend on whether there is a pre-existing

[9] Note that all CDER will also be FDER since they must post curtailment offers. However, it may be that not all FDER are CDER since the LFM is open to DERs with conventional connection agreements.

principle of access (e.g. pro rata or LIFO), and whether there is a decision to socialise some of the constraint management costs amongst the CDER or the wider DNO customer base.

2.3.2 Offer stack creation

All participating DER submit an offer price, which reflects their willingness to be curtailed. The offer volume is by default equal to the capacity of the participating DER to reduce generation (or increase demand) from their current output (or demand) level. Any underlying curtailment obligation (e.g. under pro rata or LIFO) is not factored into this calculation.

FDERs will have the option to offer less than their maximum curtailment potential if, for example, they wish to ensure a minimum level of generation. This is illustrated in Figure 1.

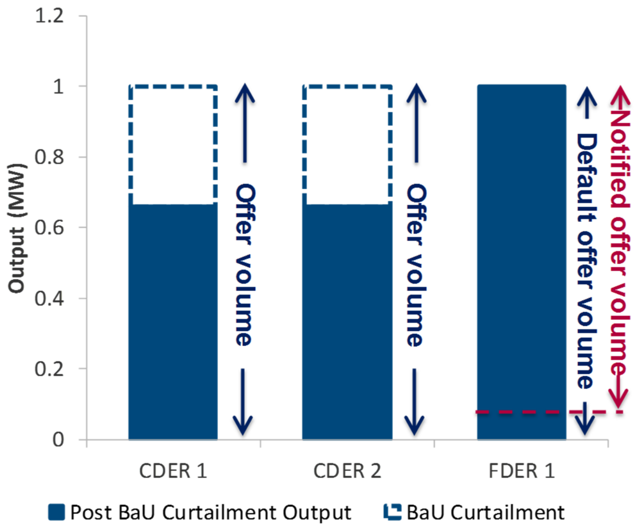

Figure 1 - Illustrative curtailment offer volumes under Approach 1

The DNO calculates sensitivity factors for each DER, based on current network operating conditions with respect to the constraint in question. The DNO then weights the offer prices and volumes by the corresponding sensitivity factors to calculate the effective offers at the constraint.

Effective offers are ordered by ascending price. When a constraint is active, the DNO accepts the lowest cost curtailment options to relieve the constraint, as illustrated in Figure 2.

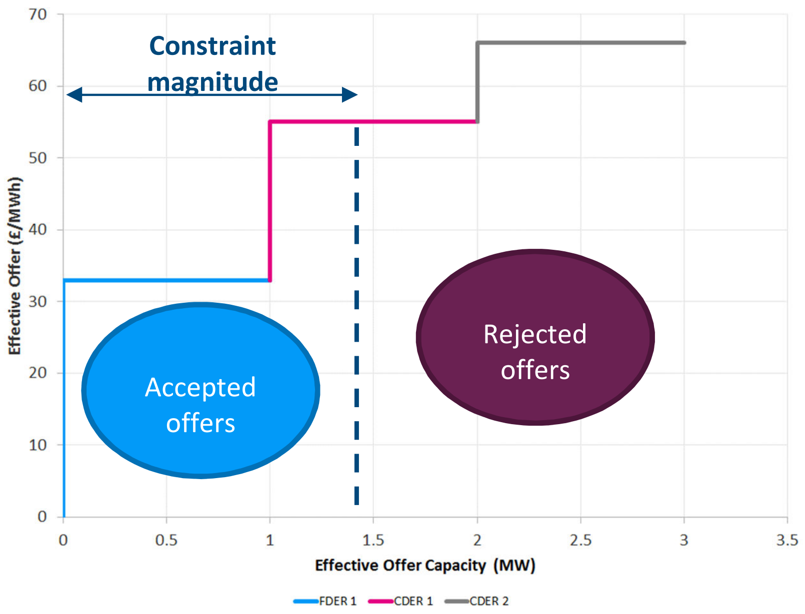

Figure 2 - Illustrative effective offer stack under Approach 1

It is proposed that payments be made on a 'pay-as-offered' basis, meaning that DER receive payments equal to the offers they make multiplied by the volume they are curtailed (or the volume of demand turn-up they deliver). This is consistent with the approach taken for most services procured by the GBSO. A possible alternative is to use a 'pay-as-clear' approach, in which case DER would be paid at a price set by the marginal DER dispatched in a particular period.[10]

Under existing Flexible Connections, an ANM system will typically curtail DER based on their output immediately before the constraint becomes binding, regardless of what would have otherwise happened to that DER during the period for which the constraint persists. Under the LFM, a similar method needs to be established to determine the level of curtailment that each DER is being subjected to, and hence on what basis they will be paid. This question of 'baselining' a DER's output is discussed further in Section 2.6.

2.3.3 Cost Recovery

The cost associated with paying accepted offers needs to be recovered. There are a number of options for doing this but, as discussed in Section 2.2, our assumption is that the scheme will need to be funded by its beneficiaries, which is to say the CDER themselves.

Note that under Approach 1, the level of curtailment that each CDER would have faced under their connection agreement (absent the LFM), hereafter the 'Business as Usual (BaU) curtailment', has no bearing on the constraint management logic under the LFM. It may be appropriate, however, to use this BaU curtailment as the basis of allocating costs to CDER.

[10] A pay-as-clear approach would require that a specific time granularity be set (e.g. 15 minute windows), in order to establish a clearing price. Current UKPN ANM system response times are within minutes.

The DNO, via the ANM system, would keep a record of the share of curtailment that each CDER would have faced under their default principles of access, and use those same proportions when calculating the payment required to cover the accepted curtailment offers in that same period. For example, if CDER 1 would have faced 80% of the curtailment volume in a period, and CDER 2 would have faced 20%, CDER 1 would pay 80% of the offers accepted during that period, and CDER 2 would pay 20%.

Such an approach presents two issues that warrant further exploration:

- The first is that by apportioning curtailment cost recovery on a simple volume-weighted basis, newly-connecting FDG are not incentivised to connect to locations that are less sensitive to the constraint. Connecting 'close' to a constraint drives up the cost of curtailment, but this burden is shared across all CDER so the impact on the connecting party can be significantly muted. This reflects the situation on the transmission network where, under connect and manage, generators are not fully exposed to the constraint management costs they impose since this cost is socialised through the Balancing Services Use of System charging mechanism.

- The second issue is that CDER with low opportunity cost can, under some circumstances, end up worse off than they would through a more simple curtailment regime such as 'pro rata'. Such a situation can arise in two ways:

  - **Low opportunity cost CDER:** A constraint is large enough to need the curtailment of more than one DER unit. Once this occurs, depending on the sensitivity factors, the CDER with the lowest offer price could be facing curtailment charges higher than its opportunity cost. Effectively, the low-cost CDER is paying to avoid further curtailment in the zone when it is already itself been fully curtailed;

  - **Low sensitivity CDER paying for high cost but high sensitivity FDER:** if a CDER has high opportunity cost but high sensitivity, its effective bid can still be lower than all other participating DER. In such circumstances, a local curtailment cost contribution for those cheaper, less sensitive CDER can be higher than their opportunity cost.

It may be that the reduction in overall curtailment (brought about by targeting well-placed FDERs that include DSR and batteries) may make all CDER better off under all circumstances, but this cannot be guaranteed. In order to alleviate this concern, it is possible to impose a cap on the level of local curtailment cost recovery that each CDER can be obliged to contribute. This cap could be set at their implied opportunity cost (£/MWh offer multiplied by their BaU curtailment level). If this cap were to be reached, there would be three options:

a) Remove the capped CDER from the market, curtailing it directly (as if it were under its BaU curtailment regime), leaving the remaining participating DER to operate in the market as normal;

b) Leave all participants in the market, but reduce the curtailment offer payments to account for the shortfall, or;

c) Increase the curtailment cost recovery contributions from the remaining CDER to make up the shortfall.

Under option a) this could result in one or more CDER being taken out of the market quite frequently, and the resulting curtailment would not be economically efficient. The main issue with option b) is that it could result in compensating DERs at a level below their opportunity cost of curtailment, thereby undermining the incentive to participate, particularly for FDER. Adopting option c) would mean that for periods with larger constraints (requiring more than one DER to manage them), those CDERs with higher offers would contribute more to the LFM fund.

By capping the local curtailment cost payments of some lower cost parties, this pushes up the costs for those CDERs with higher opportunity costs. This should be a rare occurrence, and should still leave those higher-cost parties no worse off than they would have been under a mechanistic scheme such as pro rata. Only CDER offering above their opportunity cost run the (small) risk of incurring above-cost curtailment recovery charges, so this should serve to discourage excessive bidding levels.

2.3.4 Process summary

These steps, from bidding to settlement, are laid out in Figure 3.

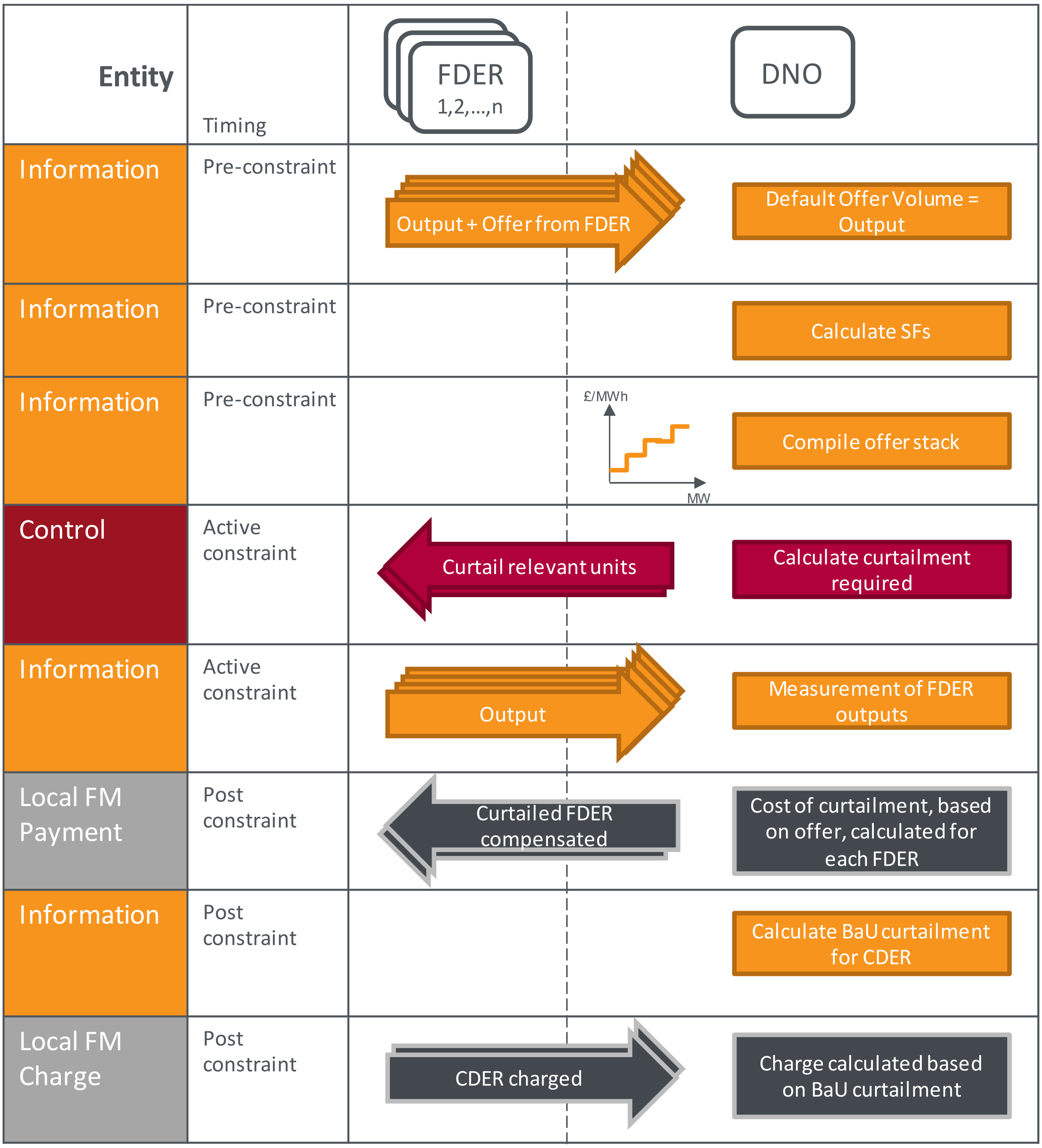

Figure 3 - Approach 1 Steps

2.4 Approach 2: DER offers matched to FDG bids

2.4.1 Overview

Under this approach, all participating DERs post curtailment offers as they did under Approach 1. However, CDERs also post curtailment bids. The DNO then applies the sensitivity calculations to each bid and offer, and creates both an 'effective bid' and an 'effective offer' stack. Where offers exceed bids, the offering DER parties are curtailed, and are paid the clearing price, determined by the intersection of the bid and offer stacks, by the successful bidders.

2.4.2 Bid-offer stack creation

Under this approach, all participating DERs submit a curtailment offer price, which reflects their willingness to be curtailed. In addition, CDER participants submit a curtailment bid price, which reflects their willingness to pay to avoid curtailment.[11] The DNO calculates the sensitivity factors, based on current network operating conditions, between DER and the local constraint for all market participants.

Bid and offer volumes are calculated based on both the CDER's actual output and the BaU Curtailment level calculated by the DNO. Effectively, the CDER is bidding to avoid a curtailment action that would otherwise be applied. FDERs, which have conventional connections, cannot therefore bid, but can offer curtailment volumes up to their current output level[12].

An example of this is shown in Figure 4, where two CDER are connected behind a local constraint, along with a FDER with a conventional connection. Under a pro-rata flexible connection agreement the two CDER would be curtailed equally in order to relieve the constraint, while the FDER has no curtailment obligation.

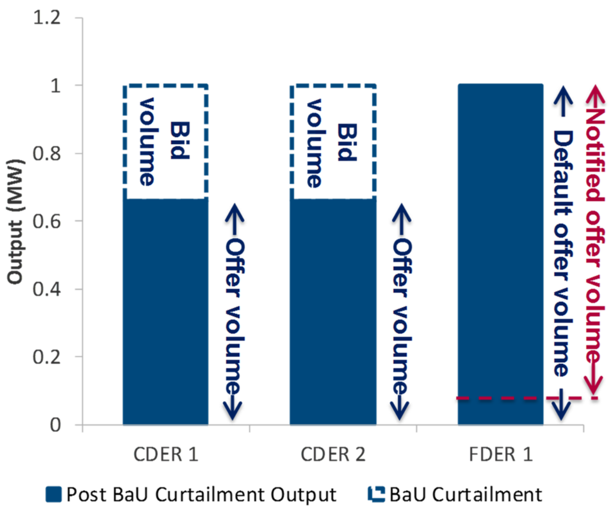

Figure 4 - BaU curtailment

Bid and offer prices and volumes are then weighted by sensitivity factors to calculate the effective bids and offers at the constraint. The effective offers are ordered by descending 'effective offer' price, and effective bids are ordered by ascending 'effective bid' price, as shown in Figure 5.

[11] As with energy markets such as the Balancing Mechanism, it is expected that a CDER's curtailment bid price will be less than their curtailment offer price.

[12] Note that in the case of a battery with a conventional connection, it can offer their charging capacity plus their current export level. A DSR unit can offer the volume of demand turn-up that they can achieve relative to their baseline output (as defined in the baseline methodology discussed in Section 2.6).

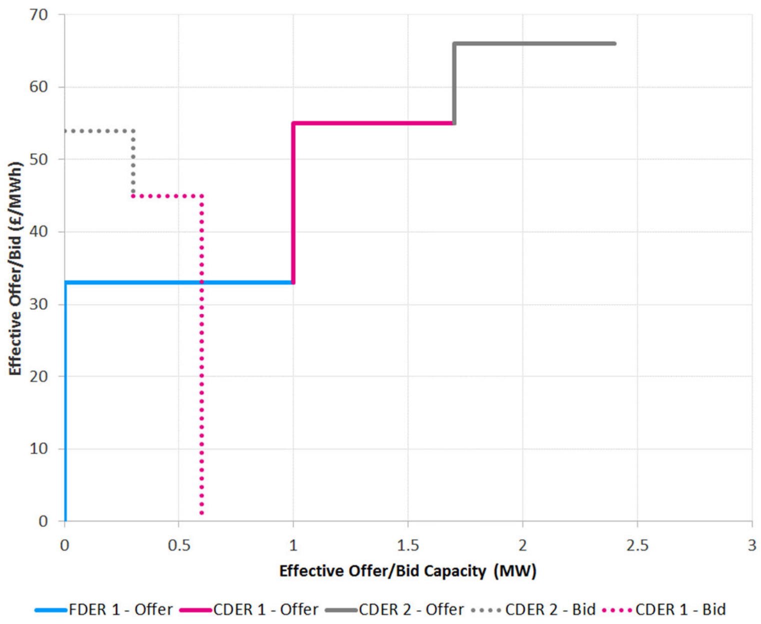

Figure 5 - Illustrative effective bid and offer stack under Approach 2

The DNO clears the market according to some predefined time window (e.g. 15 minutes), accepting descending offers and ascending bids up until the next offer price is lower than the next bid price. CDER left with unaccepted bids are curtailed based on their underlying flexible connection agreements. It is assumed that successful DER would be compensated on a 'pay-as-clear' basis, determined by the intersection of the effective bid and the effective offer stack. However, it would also be possible to operate on a 'pay-as-offered' basis.

Once the market has cleared, FDER with accepted offers (and CDER with unaccepted bids if applicable) are then dispatched by the DNO to manage the constraint. As with Approach 1, there is a need to determine the 'baseline' level of output for each FDER to ensure that the basis on which payments are made is fair (see Section 2.6).

2.4.3 Process summary

These steps, from bidding to settlement, are laid out in Figure 6.

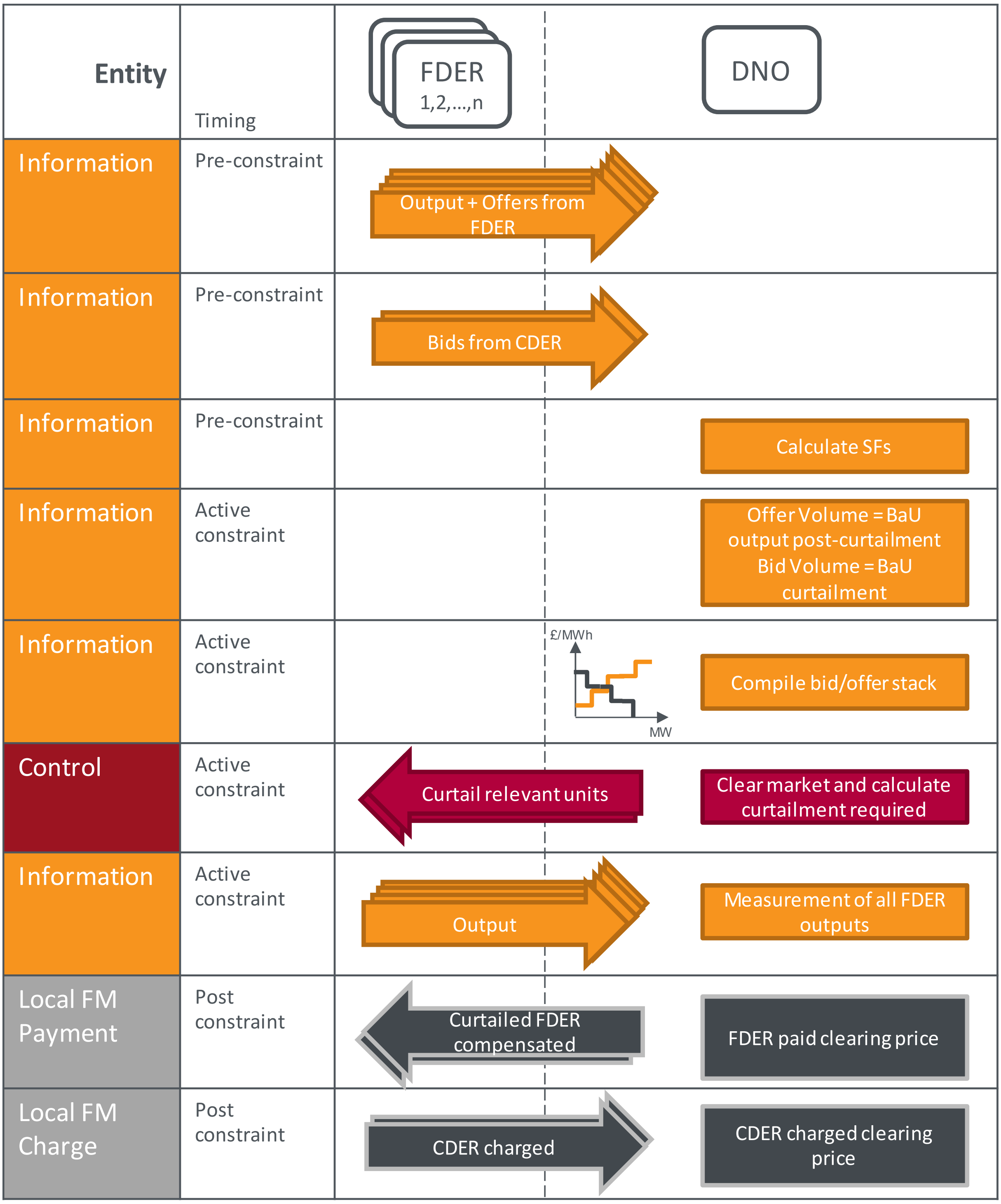

Figure 6 - Approach 2 Steps

2.5 DER pricing strategy

Whilst the underlying cost of curtailment might be the most significant component of a DER's chosen offer, it is not necessary for a DER to offer at its short run marginal cost. For example, if a battery operator chooses to connect to a region with an existing LFM and to participate in that LFM, it may attempt to cover some of its long-run costs by offering above its short run marginal costs or bidding above them.

As part of any implementation of a market-based scheme, it is important to be explicit about what bidding behaviours are allowed, and to monitor the bidding behaviour by participants. In such small markets there is a risk that strategic bidding can evolve into anti-competitive behaviour.

There may be ways to design the market that reduce the risk of anti-competitive behaviour, including:

- **Explicitly forcing participants to align their prices to their opportunity cost:** This would be administratively onerous, and would likely discourage the participation of DERs, such as batteries, seeking to extract value from the LFM as part of a project business case;
- **Ensuring a minimum level of DER participation before activating the LFM:** This might ensure there was sufficient competitive pressure in the local market but, again, could introduce risk for a developer seeking to offer flexibility services into a LFM;
- **Restricting the rate at which DER can change their bids:** This would make it less likely that a DER could exploit a short-lived period of reduced competition (i.e. scarcity pricing), but would not necessarily resolve a more prolonged period of low competition.
- **Aligning DER offers to a wider market:** In the long term, the curtailment offers made into a LFM could be used for providing wider system services (for example, under the Power Potential framework being trialled by UK Power Networks and National Grid). This would encourage a DER to price competitively, since it could then be used more frequently for providing Balancing Services.

2.6 Baselining

The LFM pays DER for decreasing their output (or increasing their consumption) when called to do so, in order to alleviate export constraints. In order to determine the level of service that has actually been provided, a method for 'baselining' the output needs to be determined. This is intended to estimate what the DER would have been doing had it not been dispatched via the LFM. The same process is adopted for a number of the GBSO's service tenders, and the methods used are varied. The approaches used typically attempt to achieve two primary outcomes:

1. The estimated counterfactual level of export/import reflects the "true" counterfactual with a low random error ('noise') and systematic error ('bias') ;
2. There is limited opportunity for DERs to 'game' the baselining calculation by implying a counterfactual behaviour that would not, in fact, have occurred.

Some options for baselining are summarised in Table 1.

Table 1 - Options for baselining

Baselining method	Description	Measurement error	Gaming risk
Historic average	Use the average demand/generation from recent history (e.g. prior similar days)	Can be low for DERs with regular usage (e.g. loads, e.g. baseload generators). High for flexible assets like batteries.	Low
Self-reported forecast	Invite DERs to submit expected demand/generation for the next day	Medium since DERs well-placed to forecast behaviour but cannot predict future.	High
Economically rational	Infer demand/generation based on what is deemed to be economically efficient (e.g. reflecting wholesale price shape)	Medium. Not appropriate for non-dispatchable generators. May work for thermal generation but more challenging for complex assets such as batteries, particularly if it has multiple contracts.	Low
Last Observation Carried Forward (LOCF)	Use the demand/generation immediately prior to calling on LFM as the baseline for the duration of the action	Medium. Does not rely on long-range forecasts but does not account for changes during the curtailment event.	Medium. DERs could anticipate constraint to increase pay-out.
Enhanced LOCF	As above, but use knowledge of the asset itself (e.g. battery load state), historic profiles, economic data or meteorological data to add shape	Low. Combining most recent data with contextual information provides more robust estimation of counterfactual.	Medium

One other consideration when choosing a baselining approach is the complexity with carrying out the measurement and calculation. A fully-fledged ANM system may be able to perform quite complex baseline estimations, whereas a more manual process may be restricted to fairly simplistic calculations.

We propose two baselining approaches for this market, with the caveat that these should be reviewed prior to any trial or roll-out to account for their practicality and to reflect any subsequent thinking emerging from related National Grid schemes such as Demand Turn Up.

- **Historic average:** This might only be used for DSR, and would follow the rules already set out for NGET's Demand Turn Up:
  - *"The baseline will be calculated using the average demand from the previous four entries for that day and time. For example, if you were instructed for Demand Turn Up on a Wednesday afternoon, the baseline would be calculated using the demand*

on the previous four Wednesday afternoons. If a Demand Turn Up instruction had also been issued on one of the four baseline Wednesdays, that day would be disregarded and the calculation would go back a week further."[13]

- **Enhanced LOCF:** This could be used for all other DERs, although the details would need to differ by technology:
  - **Non-dispatchable assets**, such as wind and solar, would be measured immediately before curtailment (or their metered output would be recorded after the fact), and would then be adjusted to account for weather changes (wind speed, insolation) assuming data availability and the technology power curve;
  - **Dispatchable thermal assets**, such as diesel generation and CHP would be measured immediately before curtailment and assumed to continue at that level for the duration of the constraint. An additional check of economic rationality could be applied *post hoc* to check for gaming behaviour;
  - **Batteries** have finite capacity meaning they cannot continue discharging (or charging) indefinitely. As a result, the baseline would initially be based on their output (or consumption) then profiled based on the initial charge state and capacity of the battery. Again, an economic rationality test could be applied *post hoc* to mitigate the risk of gaming.

In the event that a DER is called in the LFM, payments (or penalties) will depend on the behaviour of the DER against the baseline. The range of possible outcomes is that the DER:

- **Delivers the output reduction for which it was called:** It is paid based on its LFM offer;
- **Over-delivers on curtailment:** It is paid only for the volume for which it was called;
- **Under-delivers or fails to deliver on curtailment:** Is paid for any volume it delivers, and may be penalised for the shortfall;
- **Increases output:** Any DER that increases its output (or decreases its demand) during a constrained period increases the need for curtailment from other DERs. The penalty (or otherwise) will depend on the DER type:
  - **Conventionally-connected DER:** Any DER with a conventional connection, whether participating in the LFM or not, has the right to increase its output regardless of whether there is a binding constraint;
  - **Demand and CDER batteries in a charging state:** Loads connected to export-constrained networks have firm connections, and so have the right to change their consumption during a constrained period. Similarly, batteries under Flexible Connections are given the right to change their charging behaviour with no penalty, provided they do not discharge into a constraint.
  - **Flexible DG and batteries in a discharge state:** Any CDER that increases its output against a baseline during an active constraint needs to pay for the cost that this imposes on the system. It is proposed that non-punitive charges be applied at the

[13] NGET Demand Turn Up FAQs: http://www2.nationalgrid.com/UK/Services/Balancing-services/Reserve-services/Demand-Turn-Up/

end of the month to reflect the additional curtailment cost that has been imposed on the system.

Any additional constraint management costs that are not directly attributable to the over-generation of CDER will be recovered from CDER as per the logic already defined.

2.7 Evaluation of approaches against design principles

Principle	Approach 1: DER offers funded by CDER customers	Approach 2: DER offers matched to CDER bids
Cost borne by beneficiaries	Costs are borne by CDER customers, rather than wider DUoS customers, so this is consistent with the principle. Without a cap on CDER payments, CDER with low opportunity cost could be over-burdened at the expense of higher-cost CDER. With a cap, more expensive CDER, who benefit more from the market, would pay more.	Costs are borne by CDER customer rather than wider DUoS customers, so this is consistent. If the market clears, the cost is shared across bidders, but un-cleared volume results in curtailment via the underlying connection agreements.
Technology agnostic	Both approaches can be made applicable to existing or new DER, and across a wide range of technologies, provided that a suitable baselining approach can be found.	
Improvement for participants	Without caps there is a risk that low-cost CDER might not always be better off (especially for larger constraints), but the cap offers protection.	Because all parties are in control of their bids and offers they can ensure that they are no worse off under this scheme, and they can fall back onto their underlying connection agreement.
Efficient curtailment	Without caps, this approach manages the full constraint in the most cost-effective way. The use of caps, which may be needed to avoid penalising low-cost CDER, could result in some CDER falling back on their underlying connection agreement, which would reduce the efficiency.	By design, the least-cost solution is only found if the market clears. This will occur if there is a large enough volume of low-cost flexibility (e.g. under unconstrained connections) but this is not guaranteed.
Fair	Both approaches allow lower cost, or more sensitive, DERs to increase their offer prices if the LFM will bear it. This allows new entrants to secure a revenue stream, but there is a risk that such small markets result in uncompetitive behaviour. This would need to be monitored as part of any implementation.	

2.8 Procuring additional curtailment

One advantage of both of the above approaches is that they produce large amounts of information regarding offer volumes and prices. This indicates the amount of generation turn-down or demand turn-up that is available, and the price at which each participant is willing to take the required action. Whilst not the primary focus of this report, it is worth noting that in many instances the full flexibility of DERs will not be utilised to manage local network constraints.

It is conceivable, therefore, that a third party such as an aggregator or the GBSO could interact with the scheme to procure additional flexibility. To illustrate this point, consider a case in which there is a local constraint that has been alleviated under Approach 2, with the market clearing to allow the full constraint to be alleviated. With that action completed, there is now information regarding the uncalled curtailment offers on that local network. The GBSO could in principle use this system to procure additional generation curtailment or demand turn-up. Because the local network is export-constrained, taking a demand turn-up action should further alleviate rather than exacerbate the thermal constraint.

As distribution networks become increasingly constrained, and ANM schemes become more widely used, such an interaction between DERs, aggregators, DNOs and the GBSO is likely to increase. An example of this approach is currently being trialled by National Grid and UK Power Networks under the Power Potential innovation project.[14]

2.9 Funding the operation of the scheme

The markets described so far in this report do not consider the need for DNO remuneration. By design, the DNO is taking no commercial risk in any of these interactions, but there is still a cost associated with operating the scheme – a cost that would hopefully be offset by the efficiency savings that the scheme brings. Some DNO funding options that might be considered include:

- Requiring the deployment of these schemes for all DNOs, ultimately resulting in the cost being passed to DUoS customers.
- Including the operation of these schemes as part of a customer-based incentive mechanism, allowing the DNO to generate profit by facilitating these markets effectively – again this would be a cost ultimately on DUoS customers.
- Require participating CDER (and possibly FDER participants) to pay an upfront and/or ongoing fee to cover the cost of setting up and operating the scheme. This would provide a reliable source of revenue to the DNO and would be consistent with the principle that the beneficiary should pay (rather than DUoS customers), but could discourage participation, particularly for CDER with lower opportunity costs, and particularly in the early stages of the scheme's life.
- Use a form of transaction cost within the scheme itself to allow the DNO to extract revenues from the curtailment trades it facilitates. This could allow CDER to avoid additional cost that were not linked to efficiency savings, but would in effect place that risk on the DNO. Furthermore, imposing transaction costs, under Approach 2 in particular, could reduce the volume clearing in the market, thereby reducing the curtailment efficiency that the scheme is trying to deliver.

We do not take a view on which of these approaches might be most appropriate, and it is likely that it will need to be considered as part of a wider discussion of connection charging and DNO incentives.

[14] http://nationalgridconnecting.com/power-potential-ready-make-name/

2.10 Reinforcement

2.10.1 Triggering reinforcement and apportioning costs

Whilst continued curtailment could be a long-term solution, particularly if DSR and batteries bring down the cost of such actions, there may be instances in which reinforcement becomes economically optimal. As more DG connects, the size of the LFM payments will tend to increase. When the costs faced by CDER (whether through the LFM itself, or through their default curtailment regime) each year starts to exceed the annuitised cost of reinforcement, this may indicate that reinforcement is a lower-cost strategy for managing the local constraint.

If and when reinforcement is triggered, it is assumed that it would be funded predominantly by CDER, since those parties would be benefiting from the increased access that resulted. There remains the question, however, of how to apportion the reinforcement costs between parties.

The existence of historic bids and offers provides an insight into the value of network access to each CDER. This could form the basis for apportioning reinforcement costs. For example, if CDER 1's bids (or offers, in the case of Approach 1) have been consistently double those of CDER 2, it may be reasonable to assign two-thirds of the ultimate reinforcement cost to CDER 1, with only one-third being imposed on CDER 2. If the overall economic case has been made, it should result that both CDER 1 and CDER 2 are better off funding the reinforcement and securing unconstrained access, rather than continuing to pay for constraint management.

Note that this is by no means the only approach that could be taken to apportioning costs. For example, all CDER could be charged on the basis of their installed capacity, or on the estimated curtailment volume that reinforcement would alleviate. Both these approaches might have less of an adverse effect on CDER pricing behaviour, and might be deemed more consistent with the principles of access in the underlying connection agreement.

We do not take a position on the correct approach, but note that the LFM provides information regarding opportunity costs that could be valuable when trying to identify a viable approach to funding reinforcement.

2.10.2 Avoiding a lump sum cost for CDER

Even if reinforcement can be shown to be economically optimal from a cost-benefit perspective, there may still be reluctance on the part of CDER to be exposed to a lump sum liability at an unspecified time in the future. One option is for the DNO to fund the upfront cost of reinforcement, perhaps temporarily passing the initial burden to DUoS customers. Once the reinforcement has been completed, the CDER continue to pay at the same annual rate that they were facing under the LFM. These annual payments would continue until the cost of reinforcement has been met, at which point the CDER would be converted to firm connections.

The principle here is that provided a CDER can make its business case work on the basis of the estimated LFM payments, the cost of reinforcement will be no higher than this. Also, there will be no large cash payment required at some uncertain time in the future.

Under this arrangement, the CDER would in debt to the DNO (or DUoS customers) for the upfront reinforcement costs. It seems reasonable that in this case the DNO (or DUoS customers) would need to be rewarded in some way for taking on this debt. Alternatively, two other options could be considered:

- **CDER secures financing:** The flexible connection agreements could bind CDERs to fund reinforcement (subject to opt-out clauses discussed below), making then contractually liable for future funding. The DNO would need to manage the credit risk associated with this option.
- **Drip-fed reinforcement fund:** The DNO would take payments from CDER each year to build a reinforcement fund, until such time that the fund was large enough to cover the expected reinforcement cost. There are two issues with this approach: reinforcement could be triggered before the fund is large enough to cover it, or reinforcement may never be required, in which case a process is needed for returning the fund to the CDER.

2.10.3 Opt-outs

There may be instances in which a CDER would still prefer not to face the cost of reinforcement. For instance, the asset may be nearing the end of its life. In order to manage this, prior to triggering a reinforcement, the DNO would consult with the affected CDER, providing the expected cost and date of the reinforcement. Any party will have the right to opt out of funding this reinforcement, but would not be able to benefit from the additional headroom created by the eventual reinforcement. This is important in order to avoid incentives for CDER to ‘free ride’ on the reinforcement without having to pay for it.

In the event of an opt-out, it needs to be agreed how to ensure that the relevant CDER does not gain access to the additional headroom. One option is to use the ANM to continue curtailing the CDER as if the network were still constrained, but this might be seen as a perverse or unsustainable outcome. This could be particularly true if the CDER were a low-carbon generator, or a battery providing valuable system services. This issue, therefore, needs to be explored further.

3 Conclusions and Next Steps

3.1 Conclusions

This report outlines the limitations of the existing rules-based approaches to constraint management, details the proposed design of a LFM and explores the benefits that such an approach could deliver. The proposed approaches can be retrofitted to existing Flexible Connection schemes and are compatible with existing rules and regulations. However, the lessons learned could provide a valuable input into future reforms of charging, connection arrangements and locational pricing.

The implementation of the LFM has the potential to overcome the limitations of existing constraint management mechanisms by:

- Providing the mechanism for more economically and technically efficient curtailment, thereby reducing the total cost and volume of curtailment required to manage constraints;
- Accommodating alternatives to curtailment, such as DSR and battery storage, which reduces the total volume of curtailment; and
- Providing a trigger for reinforcement, allowing the DNO and CDER to make more efficient reinforcement decisions.

This report has presented a number of options for the specific design of the LFM. Where appropriate, recommendations for the best option have been made. These options require refinement through further engagement with the regulator, other DNOs, and DER customers, before a final decision is made. Carrying out a trial or small-scale deployment is a vital step in this process. This will allow the lead options to be tested and refined before adoption as Business as Usual.

3.2 Next Steps

Based on the conclusions of the report, and along with the feedback gathered from distributed asset developers at a UKPN Customer Forum, the steps required before the LFM approach can become a business as usual process are laid out:

1. Carry out a further work to quantify the expected benefit of a LFM for market participants in a selected region, both to ensure that the approach is justified and to generate interest from potential participants
   - This will use historical data collected under existing UKPN flexible connection zone schemes.
   - It will provide an indication of the expected reduction in curtailment volumes, and the potential reduction in CDER curtailment costs, that a LFM can provide.
2. Design the technical solution required to implement a LFM, either by adapting existing ANM schemes or developing a new platform
3. Select a suitable zone for testing LFM and carry out a trial

- This could be amongst existing DERs with Flexible Connections. Participation could be voluntary and limited at first to existing CDER, with participation being widened to FDER once the approach had been established.
- Alternatively, it may be more appropriate to implement LFM in a new Flexible Connection zone, with the market established up front.

4. Disseminate learnings amongst stakeholders
    - The results of the trial will be disseminated amongst the regulator, other DNOs, and DER customers and their feedback will be used to further refine the approach.
5. Roll out the LFM as a business as usual offering, ensuring that the technical solution is compatible with similar offerings
    - There are a number of concurrent projects being carried out amongst DNOs and by the GBSO to explore how DER can provide constraint management services to relieve wider distribution network constraint, as well as transmission network constraints.
    - The final solution for the LFM should be compatible with solutions adopted through other projects in order to reduce the complexity for DER, and ensure the maximum participation in the market.

The arrangements for connecting and charging network users are under review by Ofgem.[15] Any future LFM design will therefore need to be compatible with the approach ultimately agreed. As Ofgem engages on these issues with the network operators and the wider network stakeholder community, it is expected that this report and the trial outlined above would provide a valuable contribution to that conversation.

15 https://www.ofgem.gov.uk/system/files/docs/2017/11/reform_of_electricity_network_access_and_forward-looking_charges_-_a_working_paper.pdf

Appendix A Worked Examples

A.1 Example 1: 3 CDER, 1 FDER, unequal OCs, equal SFs

Consider an example of a flexible connection zone with 3 DER with Flexible Connections (CDER) connected behind a local constraint under a pro-rata curtailment scheme. For simplicity, all CDER have the same 1MW capacity and currently have 1MW outputs. In addition, there is an unconstrained FDER unit (FDER 1) that has a current output of 1.1MW. The CDER and FDER 1 have equal sensitivity factors of 100%, as shown in Table 2.

The local constraint requires a 1MW reduction in power flow in order to alleviate it. Under their pro-rata connection agreements, the 3 CDER are curtailed equally as a percentage of their output until the constraint is relieved. In this instance, each CDER is curtailed by 0.33MW, resulting in a total of 1MW of curtailed generation.

Table 2 - Example 1 Pro-rata Curtailment

Name	Sensitivity Factor	Opportunity Cost (£/MWh)	Effective Output (MW)	Curtailed Effective Output (MW)	Output Curtailed (MW)	Opportunity Cost (£)
FDER 1	*100%*	*30.00*	*1.10*	*N/A*	*N/A*	*N/A*
CDER 1	100%	50.00	1.00	0.33	0.33	16.67
CDER 2	100%	60.00	1.00	0.33	0.33	20.00
CDER 3	100%	70.00	1.00	0.33	0.33	23.33
			4.10	**1.00**	**1.00**	**60.00**

Now consider that a LFM has been established amongst participating DER behind the local constraint. Assume that the opportunity cost of the DERs is unequal, the conventionally connected FDER having a £30/MWh opportunity cost and the CDER having a range from £50/MWh to £70/MWh. Furthermore assume that offers are made at 10% above opportunity cost, and bids (for Approach 2) are made at 10% below opportunity cost.

A.1.1 Approach 1

Under Approach 1 the offer stack, shown in Figure 7 is calculated. The offer volumes are equal to the current DER outputs de-rated by the sensitivity factors to give the effective volume at the constraint. The DER offer is weighted by the sensitivity factor, in this case 100%, to give the effective offer price at the constraint.

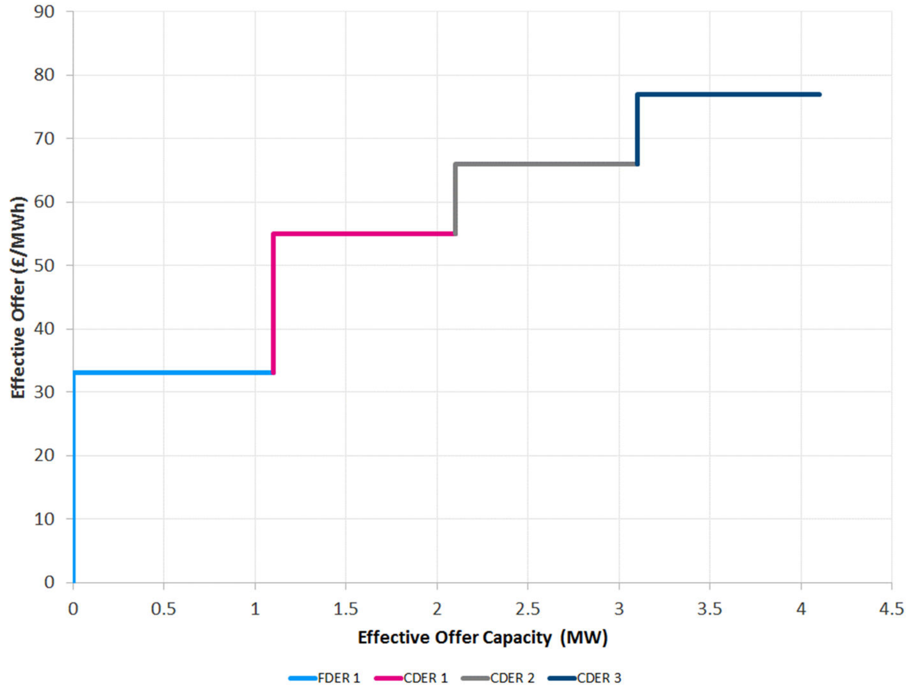

Figure 7 - Example 1 Approach 1 Offer Stack

The offer stack is then used to curtail the DER in order of ascending offer prices, until the constraint is relieved. In this example, Table 3 displays how curtailment is apportioned in order to relieve the 1MW constraint. As the sensitivity factors of the participants are equal, the FDER are curtailed in order of increasing offers. With the lowest opportunity cost, FDER 1 is fully curtailed and the CDER avoid any curtailment. The total output curtailment is 1MW, the same as under pro-rata curtailment, but the total opportunity cost is now £30, in comparison to £60 under pro-rata curtailment.

Table 3 - Example 1 Approach 1 Curtailment

Name	Sensitivity Factor	Effective Offer (MW)	Effective Offer (£/MWh)	Accepted Offer (MW)	Total Effective Curtailment (MW)	Total Output Curtailed (MW)
FDER 1	100%	1.10	33.00	1.00	1.00	1.00
CDER 1	100%	1.00	55.00	0.00	0.00	0.00
CDER 2	100%	1.00	66.00	0.00	0.00	0.00
CDER 3	100%	1.00	77.00	0.00	0.00	0.00
				1.00	**1.00**	**1.00**

Under the settlement rules of Approach 1 all accepted offers are paid for at the offer price. Therefore FDER 1 receives its offer price. This payment is funded by the CDER, who have faced a reduced curtailment obligation in comparison to their underlying pro-rata connection agreement. With equal outputs before the curtailment actions were taken, each CDER contributes an equal amount of £11 to cover the market payments, as shown in Table 4.

Table 4 - Example 1 Approach 1 Settlement

Name	Market Charge (£)	Market Payment (£)	Avoided opportunity cost (£)	**Net benefit (£)**
FDER 1	0.00	33.00	-30.00	+3.00
CDER 1	11.00	0.00	16.67	+5.67
CDER 2	11.00	0.00	20.00	+9.00
CDER 3	11.00	0.00	23.33	+12.33
	33.00	**33.00**	**30.00**	**+30.00**

A.1.2 Approach 2

Under Approach 2 the bid/offer stack, shown in Figure 8, is calculated. The bid volumes are equal to the curtailment the CDER would experience under the underlying pro-rata scheme, and the offer volumes are equal to the FDER output after any underlying curtailment obligation is considered.

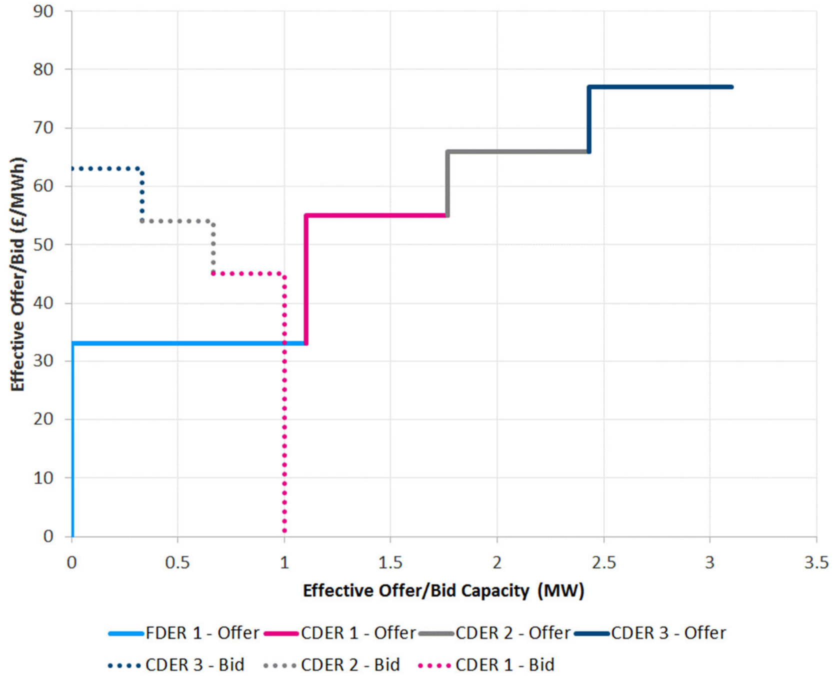

Figure 8 - Example 1 Approach 2 Bid/Offer Stack

FDER 1, the participating unconstrained DER, has the lowest offer, so it is best placed to relieve the constraint. As such, its full offer volume is accepted, taking on the full curtailment obligation of all CDER, which have higher bids. Table 5 displays the outcome of the market. The total output curtailment is 1MW, the same as under pro-rata curtailment, but the total opportunity cost is now £30, in comparison to £60 under pro-rata curtailment.

Table 5 - Example 1 Approach 2 Curtailment

Name	Sensit-ivity Factor	Effective Offer (MW)	Effective Bid (MW)	Effective Offer (£/MWh)	Effective Bid (£/MWh)	Accepted Offer (MW)	Accepted Bid (MW)	Total Effective Curtailment (MW)	Total Output Curtailed (MW)
FDER 1	100%	1.10	0.00	33.00	27.00	1.00	0.00	1.00	1.00
CDER 1	100%	0.67	0.33	55.00	45.00	0.00	0.33	0.00	0.00
CDER 2	100%	0.67	0.33	66.00	54.00	0.00	0.33	0.00	0.00
CDER 3	100%	0.67	0.33	77.00	63.00	0.00	0.33	0.00	0.00
						1.00	**1.00**	**1.00**	**1.00**

Under the settlement rules of Approach 2, the clearing offer price is set at the intersection of the bid and offer stacks, £33/MWh. Table 6 displays the charges for participants with accepted offers and payments for participants with accepted bids.

Table 6 - Example 1 Approach 2 Settlement

Name	Market Charge (£)	Market Payment (£)	Avoided opportunity cost (£)	Net benefit (£)
FDER 1	0.00	33.00	-30.00	+3.00
CDER 1	11.00	0.00	16.67	+5.67
CDER 2	11.00	0.00	20.00	+9.00
CDER 3	11.00	0.00	23.33	+12.33
	33.00	**33.00**	**30.00**	**+30.00**

In summary, FDER 1 is paid by the CDER to take on their curtailment obligations and, due to FDER 1's low opportunity cost, is able to alleviate the constraint at a lower cost.

It should be noted that the full curtailment volume might not be met through the matched bids and offers. For example, if FDER 1 in our example had had an output of 0.9MW rather than 1.1MW it alone would not have been able to alleviate the constraint. This is illustrated by Figure 9.

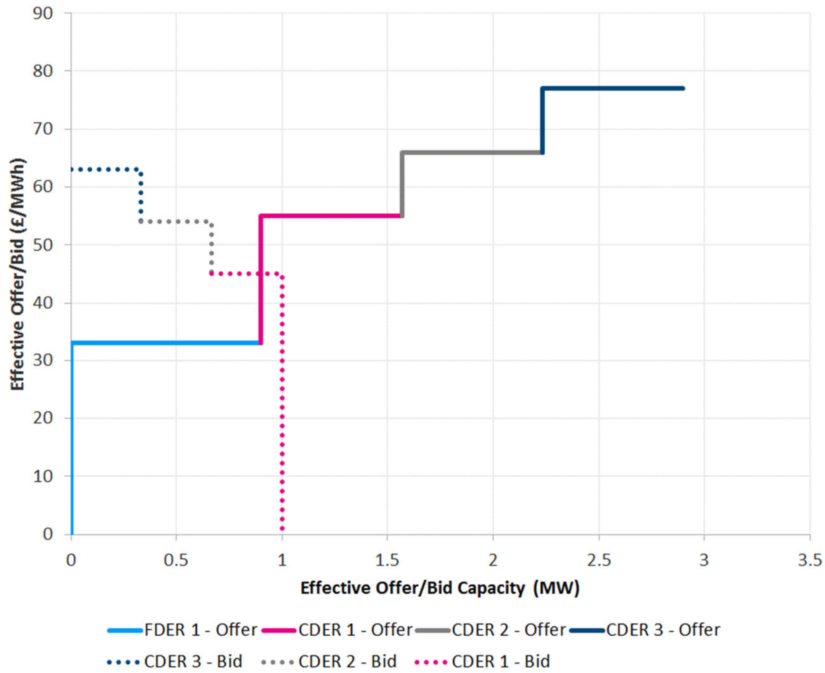

Figure 9 - Example 1a – Intersection at minimum bid – Approach 2 Bid/Offer Stack

In this case, the intersection occurs at 0.9MW at a price of £45/MWh, meaning that the curtailment cannot be fully alleviated through the cleared market. Instead, 0.9MW of the constraint is alleviate through the LFM market, but the remaining 0.1MW is apportioned to the CDER according to their underlying Flexible Connection agreement.

A.2 Example 2: 3 CDER, 1 FDER, equal OCs, unequal SFs

This example is the same as Example 1, except that the opportunity costs are common to all FDER, whereas the sensitivity factors vary, as shown in Table 7, ranging from 50% to 70%.

Again, the local constraint requires a 1MW reduction in power flow in order to alleviate it. Under their pro-rata connection agreements, the 3 CDER are curtailed equally as a percentage of their output until the constraint is relieved. In this instance, each CDER is curtailed by 0.56MW, resulting in a total of 1.67MW of curtailed generation.

Table 7 - Example 2 Pro-rata Curtailment

Name	Sensitivity Factor	Effective Output (MW)	Curtailed Effective Output (MW)	Output Curtailed (MW)
FDER 1	*80%*	*0.88*	*N/A*	*N/A*
CDER 1	70%	0.70	0.39	0.56
CDER 2	60%	0.60	0.33	0.56
CDER 3	50%	0.50	0.28	0.56
		2.70	**1.00**	**1.67**

Now consider that a LFM has been established amongst the FDER behind the local constraint, and the FDER with a conventional connection and a sensitivity to the local constraint of 80% is willing to participate. Assume that the opportunity costs of the FDER are equal (at £40/MWh) and that offers are made at 10% above opportunity cost and bids (for Approach 2) are made at 10% below opportunity cost.

A.2.1 Approach 1

Under Approach 1 the offer stack, shown in Figure 10, is calculated. The offer volumes are equal to the current FDER outputs de-rated by the sensitivity factors to give the effective volume at the constraint. The FDER offer is weighted by the sensitivity factor to give the effective bid price at the constraint.

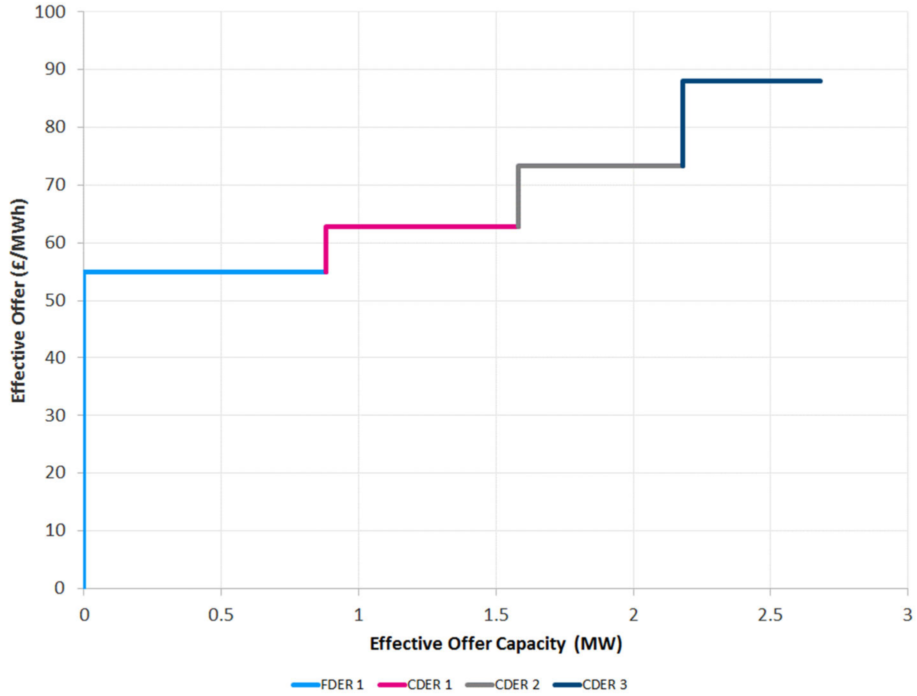

Figure 10 - Example 2 Approach 1 Offer Stack

The offer stack is then used to curtail the DER in order of ascending offer prices, until the constraint is relieved. In this example, Table 8 displays how curtailment is apportioned in order to relieve the 1MW constraint. As the offers of the participants are equal, the FDER are curtailed in order of decreasing sensitivity factor. With the highest sensitivity factor, FDER 1 is fully curtailed, and CDER 1 is partially curtailed. The total output curtailment required to relieve the constraint is 1.27MW, a reduction of 0.4MW compared to pro-rata curtailment.

Table 8 - Example 2 Approach 1 Curtailment

Name	Sensitivity Factor	Effective Offer (MW)	Effective Offer (£/MWh)	Accepted Offer (MW)	Total Effective Curtailment (MW)	Total Output Curtailed (MW)
FDER 1	80%	0.88	55.00	0.88	0.88	1.10
CDER 1	70%	0.70	62.86	0.12	0.12	0.17
CDER 2	60%	0.60	73.33	0.00	0.00	0.00
CDER 3	50%	0.50	88.00	0.00	0.00	0.00
				1.00	**1.00**	**1.27**

Under the settlement rules of Approach 1 all accepted offers are paid for at their offer price. Therefore both FDER 1 and CDER 1 receive payments via the market which covers their opportunity cost of curtailment. These payments are then funded by the CDER, who have faced a reduced curtailment obligation in comparison to their underlying pro-rata connection agreement. As shown in Table 9, with equal outputs before the curtailment actions were taken, each CDER contributes an equal amount of £18.65 to cover the market payments. This compares with £22.22, which each CDER would incur in opportunity costs under pro rata arrangements. Note that CDER 1 would incur a market charge of £18.65 minus its £7.54 market payment.

Table 9 - Example 2 Approach 1 Settlement

Name	Market Charge (£)	Market Payment (£)	Avoided opportunity cost (£)	Net benefit (£)
FDER 1	0.00	48.40	-44.00	+4.40
CDER 1	18.65	7.54	15.37	+4.26
CDER 2	18.65	0.00	22.22	+3.57
CDER 3	18.65	0.00	22.22	+3.57
	55.94	**55.94**	**15.81**	**+15.81**

A.2.2 Approach 2

Under Approach 2 the bid/offer stack, shown in Figure 11, is calculated. The bid volumes are equal to the curtailment the CDER would experience under the underlying pro-rata scheme, and the offer volumes in this example are equal to the DER output after any underlying curtailment obligation is considered. Both bid and offer volumes are de-rated by the sensitivity factor to calculate the effective volume at the constraint. The CDER bids and DER offers are weighted by the sensitivity factor to give the effective price at the constraint.

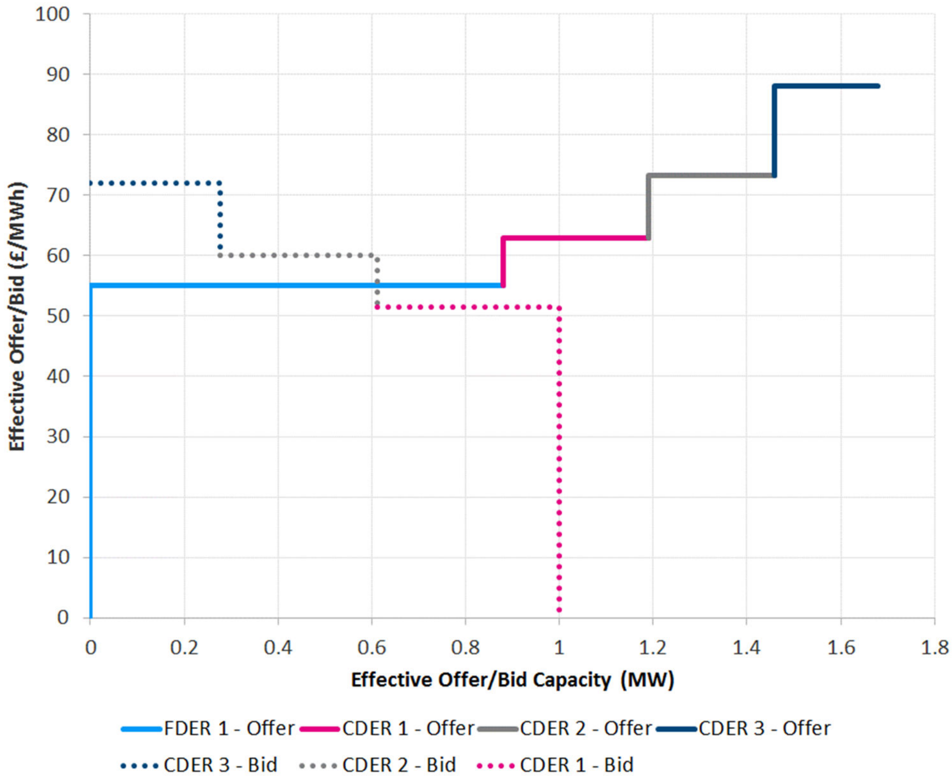

Figure 11 - Example 2 Approach 2 Bid/Offer Stack

FDER 1 has the highest sensitivity factor, and is therefore best placed to relieve the constraint. Table 10 displays the outcome of the market. Because the market clears at a volume below the 1MW required to alleviate the constraint, however, CDER 1 is still obliged to accept its BaU curtailment obligation.

Because CDER 1's bid was below the lowest curtailment offer, it simply incurs its BaU curtailment of 0.56MW, which delivers 0.39MW of constraint alleviation. The remaining 0.61MW clears in the market, and is delivered by curtailing FDER 1 by 0.76MW.

Table 10 - Example 2 Approach 2 Curtailment

Name	Sensitivity Factor	Effective Offer (MW)	Effective Bid (MW)	Effective Offer (£/MWh)	Effective Bid (£/MWh)	Accepted Offer (MW)	Accepted Bid (MW)	Total Effective Curtailment (MW)	Total Output Curtailed (MW)
FDER 1	80%	0.88	N/A	55.00	N/A	0.61	N/A	0.61	0.76
CDER 1	70%	0.31	0.39	62.86	51.43	0.00	0.00	0.39	0.56
CDER 2	60%	0.27	0.33	73.33	60.00	0.00	0.33	0.00	0.00
CDER 3	50%	0.22	0.28	88.00	72.00	0.00	0.28	0.00	0.00
						0.61	**0.61**	**1.00**	**1.32**

As shown in Table 11, FDER 1 is paid £33.61 (corresponding to the effective clearing price of £55/MWh, or £44/MWh from the perspective of FDER 1) by CDER 2 and CDER 3. Because CDER 1's bid was below FDER 1's offer, no curtailment trade occurs between these parties. Instead, CDER 1 incurs its full curtailment obligation.

Table 11 - Example 2 Approach 2 Settlement

Name	Market Charge (£)	Market Payment (£)	Avoided opportunity cost (£)	Net benefit (£)
FDER 1	0.00	33.61	-30.56	+3.06
CDER 1	0.00	0.00	0.00	+0.00
CDER 2	18.33	0.00	22.20	+3.89
CDER 3	15.28	0.00	22.20	+6.94
	33.61	**33.61**	**13.89**	**+13.89**

In this example, Approach 2 resulted in less curtailment than under pro rata, but more than was seen under Approach 1. This is because either FDER 1's offer was too high, or CDER 1's bid was too low. In practice, we might expect the bid-offer spread to reduce. With no bid-offer spread, the market would clear as shown in Figure 12, and would make use of the full flexibility of FDER 1.

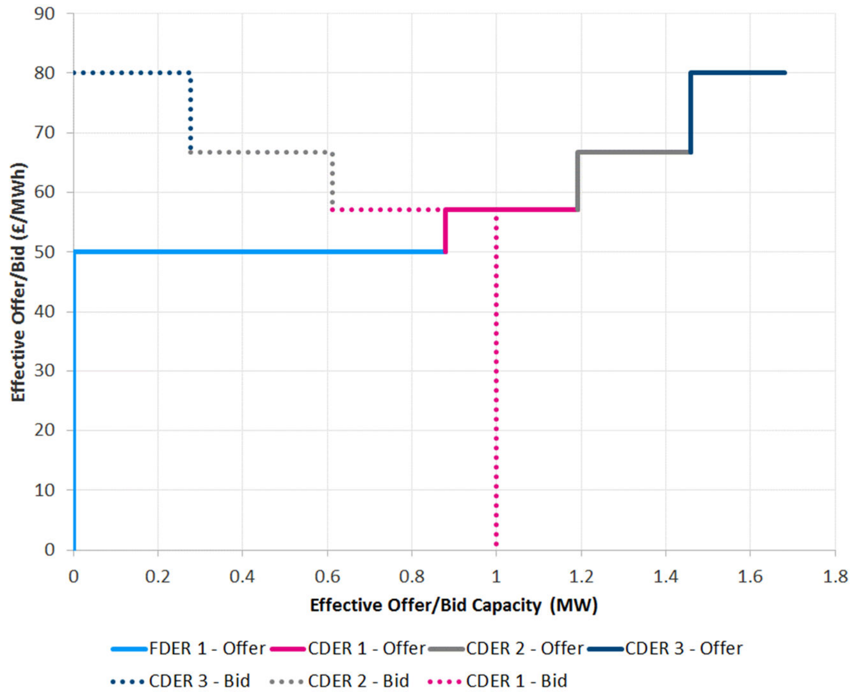

Figure 12 - Example 2 Approach 2 Bid/Offer Stack with zero B-O spread

Alternatively, provided that there are sufficient low-cost, FDER participants, it is possible to alleviate the full constraint through the market, as can be seen in Figure 13, which illustrates the case in which FDER 1's volume has been doubled and its opportunity cost has been reduced to £30/MWh.

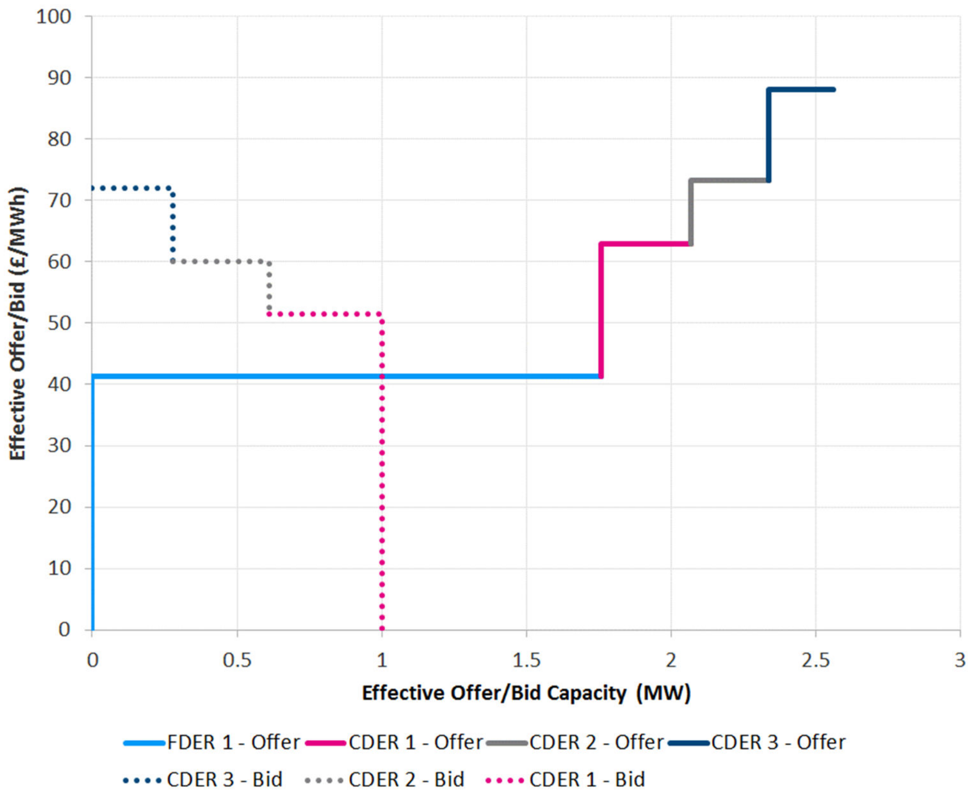

Figure 13 - Example 2 Approach 2 Bid/Offer Stack with increased DG volume and reduced cost

Appendix B Stakeholder engagement

Along with informal interaction with developers, Ofgem and other DNOs, formal engagement with existing and proposed DER customers was achieved through discussions at a UK Power Networks DG customer forum (18th July 2017). The proposed approach to distribution network constraint management through the use of market signals was presented, specific questions were asked to the audience, and a general discussion was held.

There was general agreement that the described approach is simple enough for developers to support and participate. Some developers were unaware of flexible connection agreements so may require more information before engaging more fully.

The majority of customers who expressed a view were interested in the principle. There was a particularly enthusiastic response from battery storage developers who considered the possibility of a distribution constraint management service revenue stream as very welcome. Other stakeholders were interested in the scheme but wanted to know more details before they committed to a possible trial.

A range of questions were received by stakeholders. UK Power Networks' responses have been grouped into the following categories: market operation, curtailment, reinforcement, measurement and settlement, stakeholder engagement, and DNO regulation.

Market Operation

Local flexibility markets will be formed behind a GSP or one voltage step down in order to have a competitive number of market participants. Current UKPN ANM system response time is within minutes enabling a dynamic response to constraint management. Uncontrollable assets, such as solar PV and wind, could have a constant offer in the system as their opportunity cost is unlikely to vary significantly. Participation in the market will also be voluntary.

UKPN intends to provide information to allow developers to know who they are competing against, ensuring the market is open and transparent. Settlement rules will need to discourage generation assets from connecting close to constraints as a way of extracting value from the LFM.

Curtailment

Curtailment estimates will likely be based on historical network usage and an overlay of an assumed generation profile of the connecting asset. A trial will require monitoring of each market participants output/load to determine their actions. This will then inform benchmarking of market participants in future.

Connection Reinforcement

If UKPN upgrades the network at some point in the future, the market behind that constraint will become obsolete if all participants are granted firm connections. Under the 'Second Comer' regulations a connecting customer that benefits from a previous customer's reinforcement may be additionally charged a proportion of the costs paid by the first customer.

As a voluntary scheme the connection process for batteries, and any other DER remains the same.

Settlement

Storage developers were keen to know if, when relieving curtailment obligations through charging, they would continue to face DUoS demand charges. Altering DUoS charging methodology is outside the scope of this project, but it is not a solution that should be discarded. In the context of a project trial, DSR and storage participants could reflect DUoS charges in their offers and bids in order to recover additional costs.

DNO Regulation

In GB there is a different regulatory framework for Transmission and Distribution Network Operators. National Grid has the ability to recover curtailment costs from Transmission network customers through BSUoS charges. DNOs on the other hand have no budget to fund export constraint management as there is not incentive in ED1 related to generation curtailment. DNOs must therefore take a different approach to managing generation curtailment.

A DNO is obliged to offer a firm connection to an interested customer but in the case that network reinforcement is required to accommodate the connection, the cost of reinforcement is passed on to the customer. A flexible connection offers an alternative connection option.

Conclusions

Based on the feedback from the stakeholder engagement UK Power Networks intends to:

1. Provide more in-depth detail of the scheme
2. Carry out a desktop study to quantify the benefit of constraint management through market signals
3. Carry out a trial amongst existing customers with flexible connections
4. Disseminate learnings amongst stakeholders
5. Interface this solution with similar solutions, such as the Regional Development Programmes and Innovation programmes such as Power Potential, to ensure DER services are easy to access and simple to understand

Appendix C Commercial Heads of Terms

It is assumed that all CDER will have an underlying Flexible Connection agreement. It is also assumed that this will include a number of clauses surrounding the ownership, installation, usage, maintenance, commissioning and decommissioning of the ANM system itself. Rather than replicating these clauses here, this appendix focuses on the Commercial Heads of Terms (CHoT) that will be particular to a market-based Flexible Connection solution. Its intention is to help the reader to understand how the LFM would work, and to understand the various roles, rights and responsibilities of the involved parties. The CHoT below are worded to refer to Approach 2 since Approach 1 is largely a subset that excludes the concept of curtailment bids. The CHoT also exclude terms relating to future reinforcement obligations.

Product term	Findings
1. Bids	*[Applies only to DER under Flexible Connections]*
1.1. Bid submission	At any time, the CDER Customer can submit to the Company through the Market Platform: a. the price, expressed in £/MWh, that it would be prepared pay to reduce its BAU Curtailment ("**Bid Price**"); b. the increase in its output above the BAU Output, expressed in MW, that the CDER Customer is bidding to secure at that Bid Price ("**Bid Volume**"); c. the period of time over which this Bid Price and Bid Volumes should apply (the "**Bid Window**")
1.2. Bid acceptance	In relation to any Settlement Period falling within a Bid Window, the Company shall accept a Bid Volume (or part thereof) if there is sufficient offered volume from other DER Resource in the relevant Settlement Period at a price at or below the applicable Bid Price; In the event that the Company accepts a Bid (or any part thereof), it shall issue an Instruction to the ANM Scheme to prevent a decrease in the Output of the FDG Customer relative to its BAU Output for the duration of the relevant Settlement Period ("**Reduced Curtailment**"), provided that this cannot exceed the Bid Volume.

1.3. Bid Settlement	At the end of each calendar month, the Company shall provide CDER Customer with a written statement setting out: - the number of Settlement Periods where it benefitted from Reduced Curtailment as a result of the Company accepting a Bid in accordance with clause 3.2 above; an - in respect of each such Settlement Period, the clearing price (expressed in £/MWh) at which other Participating DER were willing to provide increased demand or accept increased curtailment - the gross amount payable from the CDER Customer to the Company in respect of Bids accepted ("**Bid Payment**")
2. Offers	
2.1. Offer Submission	At any time, the FDER Customer can notify the Company of: a. the price, expressed in £/MWh, that it would prepared to be accept in order to increase is BAU Curtailment ("**Offer Price**") b. the decrease in its output above the BAU Output, expressed in MW, that the FDER Customer is offering at that price ("**Offered Volume**"); c. the period of time over which this Bid Price and Bid Volumes should apply (the "**Offer Window**")
2.2. Offer Acceptance	In relation to any Settlement Period falling within an Offer Window, the Company shall accept the Offered Volume (or part thereof) if there is sufficient bid volume from other Participating DER in the relevant Settlement Period at a price at or above the applicable Offer Price; In the event that the Company accepts an Offer (or any part thereof), it shall issue an Instruction to the ANM Scheme to decrease the Output of the FDG Customer relative to its BAU Output for the duration of the relevant Settlement Period ("**Increased Curtailment**"), provided that this increase in Output cannot exceed the Offered Volume.

2.3. Offer Settlement	At the end of each calendar month, the Company shall provide FDER Customer with a written statement setting out: - the number of Settlement Periods where it experienced Increased Curtailment as a result of the Company accepting an Offer in accordance with clause 5.2 above; - in respect of each such Settlement Period, the marginal bid price (expressed in £/MWh) at which other participating DER were willing to pay for reduced curtailment; and - the gross amount payable from the Company to the FDER Customer in respect of all Offers accepted in that month ("**Offer Revenue**")