

Whole Electricity System Operation

Commercial Interfaces with DER

Options Paper for discussion

Author:	Ian Pashley
Purpose:	To explore the advantages of different DSO commercial models and their practical application to Regional Development Programmes and beyond
Audience:	NGESO (internal); Wider Industry (external)
Date:	19/08/2019
Version:	1.2

Executive Summary

Through our Regional Development Programmes (RDPs) and the ENA's Open networks project we are introducing new ways of working that significantly enhance transmission and distribution systems coordination and control, creating whole system efficiencies and providing new tools and resources to manage system constraints – ultimately reducing costs for customers.

Our RDPs are enabling further DER connections in constrained areas of the network, but without timely implementation of corresponding commercial mechanisms to access DER services to manage transmission constraints, further DER connections in these areas may need to be put on hold, pending installation of additional network infrastructure to accommodate them. We are keen to progress a coordinated approach that is acceptable to both DNOs and DER.

We need a whole system approach with our stakeholders to deliver services efficiently and effectively. We are keen to agree a consistent approach across the DNO community for sustainable access to DER services from both NGESO and DSOs – strong whole electricity system working is a key element of our business plan proposals for the RII0-2 period, and we believe the development of a coordinated approach is an important step for this work. This paper describes three potential methods and considers their relative merits, before proposing a way forward to meet near-term needs.

The characteristics of each method must ensure system needs can be met at all times. Accordingly, there are objectives that will need to be satisfied by each method for use of services from DER, to ensure secure network operation and efficiency of wholesale market and settlement processes:

- Arrangements must meet NGESO and DSO needs for national and local flexibility services. They must be deliverable in the short-term to meet NGESO's immediate system operation needs but be sufficiently flexible to adapt in the longer-term as industry roles and responsibilities evolve;
- System Operators retain responsibility for the safe and secure operation of their respective networks;
- DER should be able to provide services to whoever they wish, having secured appropriate rights to flow power;
- As much as possible, DER should be able to participate in multiple complementary markets for services, stacking revenues as appropriate;
- The role of the DSO as a market facilitator/technical gatekeeper must be allowed to develop and evolve; and

- Arrangements must be compatible with existing wholesale market provisions and align with the Balancing Mechanism (including ‘wider access’ arrangements and TERRE).

The merits of the three proposed methods, against these objectives, can be summarised as follows:

Objectives	Method 1: NGESO/DSO Coordinated Approach	Method 2: DSO operates VPP at the GSP	Method 3: DSO operates GSP within its technical capability
Meets NGESO needs	Green	Green	Green
Meets DSO needs	Green	Green	Green
Ease of engagement by DER	Green	Green	Green
Compatibility with existing wholesale market provisions	Green	Red	Red
Ease of implementation	Yellow	Yellow	Red
Flexibility for the future	Green	Green	Red

Next steps

It is assumed that all methods could be designed such that they meet the needs of DER, DSOs and NGESO.

Decisions associated with this issue are critical to the design of IT development that will give effect to visibility and controllability of DER in the control environment. Until the commercial approach is agreed it will not be possible to efficiently design the IT solution, as multiple potential approaches will need to be accommodated. It also makes it difficult to give firm answers to customer questions on how the arrangements will operate.

However, the consequences of each method, and the scale of change required, suggest a clear implementation approach. **It is recommended that method 1 is adopted in the near-term**, so that NGESO can ensure efficient ongoing management of transmission constraints, and access to DER for provision of other services.

This view aligns with the conclusion of Baringa’s Future Worlds impact assessment, which suggests the continuation of a coordinated approach until certain key trigger points, such as the implementation of reformed access and forward-looking charging arrangements. It is not expected that progressing method 1 would preclude adopting alternative approaches in future, to align with evolving industry roles and responsibilities.

1. Introduction

New decentralised energy resources are connecting to distribution networks, making them into active networks and transforming the role of Distribution Network Operators (DNOs). Many of these stakeholders can provide valuable services to NGENSO and also these emerging Distribution System Operators (DSOs).

We need a whole system approach with our stakeholders to deliver services efficiently and effectively. Through our collaborative Regional Development Programmes (RDPs) and the ENA's Open networks project we are introducing new ways of working that significantly enhance transmission and distribution systems coordination and control, creating whole system efficiencies and providing new tools and resources to manage system constraints – ultimately reducing costs for customers.

However, the potential roles and responsibilities across industry to deliver this future remain in flux. Our RDPs are enabling further DER connections in constrained areas of the network, but to date we have been unable to agree an appropriate contract form to cover NGENSO, DNOs and DER. Without timely implementation of corresponding commercial mechanisms to access DER services to manage transmission constraints, further DER connections in these areas may need to be put on hold, pending installation of additional network infrastructure to accommodate them.

This paper considers a range of options for NGENSO gaining access to DER to support the management of the GB transmission system. It considers the immediate need to access DER to deliver the capabilities identified in our RDPs, as well as broader provision by DER of other NGENSO and DSO services.

The RDPs are aiming to trial a 'design by doing' approach with willing partners across the GB transmission and distribution networks. Through utilising whole electricity system coordination of network analysis, design and optioneering, the aim of the RDPs is to trial better transmission and distribution solutions for customers and end consumers, with the intention of feeding back findings to the ENA, in readiness for implementation into industry codes and frameworks.

We are currently undertaking five RDPs across GB, each of which vary in complexity and maturity with respect to design and implementation timescales. All these RDPs require us to have access to DER to undertake transmission constraint management activities. The commercial approach will need to support enhanced transmission and distribution system coordination and control, and procurement of DER services by both NGENSO and DNOs.

The key features of the RDPs are summarised below. We then consider what commercial approaches might best meet their needs, as well as facilitating DER provision of services more broadly. Finally, we look at the practicalities of implementation so that current needs can be met, as well as a range of future scenarios.

2. Overview of Regional Development Programmes

UKPN South-East Coast RDP

The South-East Coast RDP aims to facilitate further efficient deployment of DER in what is one of the most complex network areas in Europe – having several interconnections to continental Europe (either currently in service or due to be commissioned), a nuclear power station, and a significant volume of renewable and traditional energy resources connected to the distribution network. The RDP looks across the whole-system landscape to unlock additional network capacity, analyse the most economic transmission system development options and open new revenue streams for market participants.

WPD South-West Peninsula RDP

The exposed position of South West England has enabled it to become a favoured location for renewable generation. It is also an area where traditional modelling indicates the network's ability to absorb that energy may be an issue after 2020. The South-West Peninsula RDP seeks to enable further renewables deployment in the region, through a whole system analysis of network capacity requirements and capabilities, and an assessment of the most cost-effective way of enabling renewable generation to connect to the whole network.

SPEN Dumfries and Galloway RDP

The transmission network in Dumfries and Galloway has historically been challenging to manage from a System Operator perspective due to the large volume of embedded, uncontrollable DER which, coupled with the fact that most

of the 132kV network is operating at capacity, has led to operability challenges over recent years. For this reason, new generation connections have adopted a staged connection approach, including the need to deploy Load Management Schemes.

To release further connection capacity, Scottish Power Transmission and NGENSO undertook a Strategic Wider Works (SWW) economic assessment, which compared the cost of a range of transmission 'build' solutions against the cost of operationally managing the constrained group. The SWW assessment recommended minimal 132kV network upgrades in the Dumfries and Galloway area, with the remainder of the transmission network constraints being managed by NGENSO. The economic assessment concluded in this way because of the intermittent load factor of the predominate wind generation and the high cost of reinforcement. However, the resulting volumes of constraint management required under windy conditions are sufficient to create operability challenges, that need to be managed through the use of commercial services.

WPD West Midlands RDP

Both transmission and distribution future energy scenarios have highlighted significant growth in energy storage within the UK over the next decade. Both NGENSO and WPD anticipate that a high growth scenario could see more than 10GW of energy storage being connected in the UK by 2030. WPD currently has over 840MW of energy storage either connected or accepted in the West Midlands licence area and, by traditional interpretation of required capacity, this is beginning to impact on the reinforcement requirements for transmission assets at the T-D boundary.

As, from a wholesale market perspective, storage provides a similar function to generation, this RDP is looking to extend the flexibility arrangements given to generation so that they also apply for storage demand. This will enable storage projects to become part of the solution to network capacity issues rather than capacity planning standards being a potential blocker to them connecting. This RDP seeks to allow energy storage, or other customers who can provide flexibility to the system, to connect with minimal reinforcements, participate in emerging whole system energy markets and receive revenues for delivering services when the system needs flexibility to deliver capacity in constrained areas.

ENW North-West RDP

The Heysham GSP provides a connection point for nuclear power station auxiliaries, local DNO supplies, a significant volume of both transmission and distribution connected wind generation and now is the requested connection point for a variety of potential new DER projects. The GSP is restricted by fault levels and, by traditional means, thermal capacity. A fourth SGT has previously been proposed, but is limited in effect, owing to the fault level issues. The RDP seeks to evaluate the most appropriate solution for capacity at the GSP, taking into account the opportunities to more actively operate the DER in the area.

Providing Visibility and Controllability of DER Output

As part of the work carried out under the above RDPs, the connection agreements with individual Customers¹ via the DNO have been updated to provide us with basic visibility and control of DER output. This obligation is necessary to ensure that parties wishing to connect to parts of the transmission or distribution systems covered by the RDPs understand their requirement to enable us to operationally manage the transmission network in scenarios where, traditionally, physical infrastructure assets would have been in place.

Traditionally, we gain visibility and control of output only from parties with which we have a Connection and Use of System Code (CUSC) connection contract. However, one of the main aims of the RDPs has been to ensure DNOs can continue to make connection offers to DER when sufficient transmission capacity may not be available to fully accommodate these additional connections under certain scenarios. So, we now require more systematic access to services from DER to manage transmission impacts arising from their connection. These RDP requirements are consistent with recent technical requirements imposed on DER by Engineering Recommendation G99, which is part of the GB response to European legislation on Requirements for Generators. These requirements have therefore been added to DNO Bilateral Connection Agreements as a form of Enabling Works, in place of traditional transmission 'build' options.

¹ Subsequently, Engineering Recommendation G99 has been updated to oblige DER to give control to DNOs, so the contractual clauses are now more on the DNO to enable use of that capability by NGENSO.

Providing Commercial Market Access

Customers should be afforded the choice as to which commercial markets they wish to participate in, so the connection agreements are therefore limited to capturing the technical requirements to enable visibility and control of DER output - they do not specify the commercial mechanism under which that party will be compensated for service provision. Dependent upon how 'active' an individual connectee wishes to be, they currently have a range of ways in which they can engage with balancing services markets; including:

- Full Balancing Mechanism (BM) arrangements;
- BM Wider Access (BM Lite/Project TERRE) arrangements; and
- via balancing services contract with NGENSO (such as the DER Transmission Constraint Management (DER TCM) service);

The first two options either already exist or are planned to be delivered by the end of 2019. The development of DER TCM (as a new ESO ancillary service) is a requirement driven by the RDPs and is aimed at offering a low-cost alternative for DER to provide transmission constraint management services to NGENSO, with a vastly reduced administrative burden.

As the BM and Wider BM Access routes will utilise existing, well developed industry processes, it's not likely that the development and implementation of distribution system operation within GB will have a significant impact on how these markets are administered, or how they operate – although there is a need to understand how distribution network capacity impacts the availability of DER in those mechanisms.

This is not necessarily the case for DER TCM, where the detailed roles, responsibilities and activities need to be worked through. We explore the potential implications of this in the next section.

3. Methods for NGESO to Access DER

We now consider three potential methods through which NGESO and DNOs could access services from DER. These are based on the ENA Open Networks project 'Future Worlds' A ('DSO Coordinates') and B ('Coordinated DSO-ESO procurement and dispatch') and we explore the characteristics of each option from the perspective of NGESO, DSOs and DER. Note that, for the purposes of this section, DNOs are referred to in a distribution system operation context (i.e. as DSOs).

Objectives to be Met

When considering the characteristics of each method, it is important to note that what is appropriate now may change in the future, to reflect changes in roles and responsibilities, and technological developments. However, the prevailing approach will need to efficiently enable system needs to be met at all times. Accordingly, there are objectives that will need to be satisfied by each method for use of services from DER, to ensure wholesale market and settlement processes continue to operate effectively:

- Arrangements must meet NGESO and DSO needs for national and local flexibility services. They must be deliverable in the short-term to meet NGESO's immediate system operation needs but be sufficiently flexible to adapt in the longer-term as industry roles and responsibilities evolve;
- System Operators retain responsibility for the safe and secure operation of their respective networks;
- DER should be able to provide services to whoever they wish, having secured appropriate rights to flow power;
- As much as possible, DER should be able to participate in multiple complementary markets for services, stacking revenues as appropriate;
- The role of the DSO as a market facilitator/technical gatekeeper must be allowed to develop and evolve; and
- Arrangements must be compatible with existing wholesale market provisions and align with the Balancing Mechanism (including 'wider access' arrangements and TERRE).

To deliver these objectives, it is expected that DSOs will need to take on new roles and responsibilities, depending on the method used. These are expanded upon in the sections below. Whilst this paper doesn't seek to recommend a desired future end-state, it considers the practicalities of implementation for each method, such that a way forward can be agreed that delivers appropriate access to DER by NGESO in the near-term.

Method 1: NGESO/DSO Coordinated Approach

The aim of this approach is for both NGESO and the DSO to procure services from DER to support operation of their networks. This represents an evolution of the current approach, which sees increased cooperation and coordination between NGESO and DSOs to drive efficient procurement and dispatch of services. So:

- Both the DSO and NGESO would procure services to meet their own network needs, coordinating on a regional basis to drive efficiencies;
- DER would contract with both the DSO and NGESO. This could be on a separate basis, or through tripartite arrangements where all three parties need to cooperate/collaborate to deliver a specific outcome – such as understanding the impact of the distribution network on provision of transmission constraint management services from DER to NGESO;
- The DSO and NGESO would cooperate on utilisation of services from DER, to ensure efficient utilisation and minimise the risk of counter-acting instructions; and
- The DSO would 'facilitate' DER service provision to NGESO. This could involve advising NGESO of any limitations in the ability to access services from the DER, managing the operation of ANM schemes to prevent back-fill of DER curtailment, or other activities that support service delivery. It would be expected that the complexity of this challenge, and hence the most appropriate way of tackling it, would vary by region – depending on the complexity of the distribution network and interactions with current or future transmission system issues.

The DER would continue to participate in wholesale market as normal, so would maintain current relationships with Suppliers, etc. NGESO would dispatch services using the most appropriate mechanism (including, in some cases, the use of automation of dispatch instructions), whether that is via the BM, BM 'wider access'/TERRE provisions (once implemented), or under balancing service contract terms. The DSO would dispatch using its own DSO services

provisions. Where the DER TCM route is chosen, the DSO may² facilitate the active power instruction between NGENSO and selected DER, using facilities required by Engineering Recommendation G99.

Supplier imbalance is avoided for NGENSO services, as BM Bid-Offer Acceptances (BOAs) and Balancing Services instructions issued by NGENSO represent firm energy contracts. Currently, any instructions from the DSO are not subject to the same treatment, so without further development, DSO instructions would affect the contractual balance of the DERs' Supplier.

What would this mean for DER?

This approach ensures that DER have choice regarding whether to sell services directly to NGENSO, to the DSO or, via aggregation to either NGENSO or the DSO. There should be little impact on existing embedded BM Units – their ability to provide services via the distribution network to NGENSO should continue, utilising existing provisions for dealing with the consequences of distribution constraints, such as the information exchanges set out in Balancing Code 1.6.1³ of the Grid Code. These same provisions could apply equally where the embedded BM Unit seeks to provide services to the DSO, where such provision might limit the availability of bids and offers to NGENSO.

Those that decide on aggregation would have a choice of commercial aggregation services. However, the impact of distribution network limitations on the ability of aggregated DER to deliver services to NGENSO might require enhancements to the way information is currently exchanged under the provisions of Grid Code BC 1.6.1. Also, if aggregation were to be used to enable provision of transmission constraint management services, it would be important to ensure that the constituent parts of the aggregated entity could be identified down to a 'per GSP' basis.

What would this mean for the DSO?

DSOs are already actively procuring flexibility services from DER connected to their networks, to assist in the management of network flows and to optimise use of network capacity. Through these procurement activities they have developed, or are developing, the capabilities and processes that will support their greater use of flexibility. Coordination of procurement and utilisation of services between DSOs and NGENSO – as required by this approach - is being pursued through the RDPs and the Open Networks project, which is seeking to develop a consistent approach across DSOs that DER can benefit from.

For NGENSO, it is important to understand the impact that distribution network capacity will have on the availability and delivery of services from DER. Equally, for DSOs, it is important to understand which DER are likely to be providing services to NGENSO, so that the consequences can be understood. For the purposes of this paper, it is assumed that the technical capability to coordinate between DSOs and NGENSO will be delivered through these mechanisms. From a commercial perspective, we believe further work is required to understand the requirements that flow from this coordinated approach, and how it should be formalised:

- Coordination activities between NGENSO and DSOs could be captured in a 'best practice' document, with contracts between NGENSO and DER for provision of transmission balancing services;
- Coordination could be managed through a three-way contract between NGENSO, DSOs and DER; or
- Coordination could be formalised in a regulatory framework/code environment.

The code route would be a longer-term aim and may form part of wider work to formalise the relationship between NGENSO and DSOs. The 'best practice' route should be more straightforward to derive and implement but would lack the certainty of a contractual approach with clearly-defined rights and obligations on all parties. It should be noted that most of the service co-ordination would be done ahead of real time, requiring only a few actions within operational timescales. The detail of how this would work needs to be established.

How would this fit within current charging and access arrangements?

From a transmission perspective, there would be nothing in the current access and charging arrangements that would prevent DER from providing services to NGENSO and being paid for them. It would be expected that such service provision feed via Balancing Services Adjustment Data into standard settlement processes alongside other balancing

² G99 obliges the DER to provide active power curtailment (type B) / set point (type C) control to the DNO and so NGENSO would need to access that via the DNO, unless the DER volunteers a direct control route.

³ BC1.6.1 provides for information exchanges between DER, DNOs and NGENSO regarding the impact of distribution constraints on an embedded BMU's ability to participate in the Balancing Mechanism.

services actions, and into Balancing Services Use of System charges, to facilitate service remuneration, enforcement of rights and obligations, and to allow for appropriate cost-recovery.

From a distribution perspective, it would be expected that DSOs would continue to procure flexibility services as an alternative to asset build, as they are doing now (following a suitable cost/benefit assessment) and fund them out of their general reinforcement budgets. Ongoing work within Open networks aims to promote consistency and best-practice in this regard. The implications on charging and access arrangements of DSOs increasingly procuring flexibility services to manage their networks would need to be worked through, to ensure that distribution charging and access arrangements, and Distribution Use of System Charges (DUoS), remain appropriate.

Conclusions

As Method 1 is an evolution of current arrangements, roles and responsibilities, it should be the most straightforward to deliver in the near-term. We anticipate the following activities will be required to deliver a workable version of Method 1:

- Extension of NGENSO’s transmission constraint management service terms to enable tri-party approach to service delivery; and
- Establishment of inter-control point communications to understand ability of distribution network to deliver DER services to NGENSO.

As our need is immediate for access to further DER to provide transmission constraint management services, we consider method 1 to be an expedient way of enabling us to manage the impact of our RDP deliverables on the transmission network in the near-term. We would expect to collaborate with DSOs and the DER community to refine the terms for service provision as experience is gained of their operation.

Our summary assessment of method 1 against the objectives previously set out, is as follows:

Objectives	Method 1: NGENSO/DSO Coordinated Approach	RAG/ Timescales/ Complexity
Meets NGENSO needs	Allows NGENSO to contract with DER for provision of NGENSO services from DER Develops the DSO’s role in provision of NGENSO services by DER	
Meets DSO needs	Allows DSOs to contract with DER for provision of DSO services	
Ease of engagement by DER	Provides clear routes to participation in NGENSO and DSO services, and hence the ability to optimise participation across a range of services Requirement to engage with two contract counterparties, rather than one, would be efficiently managed	
Compatibility with existing wholesale market provisions	Provision of services from DER to NGENSO would be captured in standard balancing services processes, so they would be settled and fed into wholesale market processes on the same basis as other NGENSO services	
Ease of implementation	Contract development would be based on existing transmission constraint management service, with DER and DSO-specific additions Systems development would be based on RDP design conclusions and ongoing developments via Open networks DER engagement would use existing DSO forums with NGENSO support	
Flexibility for the future	Terms established within the contracts binding DER, DSOs and NGENSO can be varied to reflect changing circumstances Nothing in the terms would preclude further structural change within the industry, which may render the terms obsolete	

Method 2: DSO operates Virtual Power Plant at the GSP

The aim of this approach would be to allow the DSO to use its understanding of the capability of the distribution network to offer a ‘firm’ MW service to NGENSO from DER within the GSP. The service could be for both decreases and increases in offtake from the GSP and could potentially cover other active and reactive power Balancing Services.

A VPP at a GSP is, in effect, an aggregated BM Unit for the purposes of BM operation. One option would be to develop specific Balancing Services contract terms to provide for a DSO to be an aggregated Balancing Services

provider at a GSP; an alternative would be to use the provisions brought in by Balancing & Settlement Code (BSC) Modification P344 for Project TERRE, which establishes the concept of an aggregated 'Secondary BM Unit'; and are due to take effect towards the end of 2019. Either way, the expectations on the DSO for operation of the VPP would be similar.

It should be noted that Ofgem have stated that they do not⁴ consider DSOs managing VPPs to be appropriate. So, what follows in this section is for illustrative purposes only.

If we consider the 'Secondary BM Unit' approach, the following provisions would be expected to apply to DSOs (note that, if a Balancing Services contract route were followed instead, we would expect the principles to be the same):

- The DSO would need to provide all relevant data to support the operation and settlement of the Virtual BM Unit, including forecasting⁵ of Final Physical Notifications, Dynamic Data, Bid-Offer Data and half-hourly metered data; to facilitate their ongoing participation in the Balancing Mechanism (forecast data would need to be provided and updated against a changing D and T background); and
- The DSO (and, for that matter, any other VPP provider) would need to be able to guarantee that the VPP was GSP-specific, to allow for management of transmission constraints. For P344, the scope of aggregation is broader, being limited to GSP Group (which represents a DNO area).

NGESO would then be able to treat the VPP as it would any other BM Unit, for the purposes of undertaking its 'residual balancer' role.

What would this mean for DER?

The component parts of the VPP (i.e. DER; or other demand-side response) would continue to participate in wholesale market as normal, so would maintain current relationships with Suppliers, etc. The expectation would be that DER continue to have choice regarding whether to sell services directly to NGESO, to the DSO or, via aggregation to either NGESO or the DSO. There should still be little impact on existing embedded BM Units – their ability to provide services via the distribution network to NGESO should continue as described previously.

Those that decide on aggregation would have the choice of going via a standard commercial route, or via the DSO. VPPs would need to understand the impact of distribution network limitations on their ability to provide services. This may be easier for a VPP managed by a DSO, as the information to adjust the VPP's availability to reflect distribution network limitations should be readily accessible. However, new processes may need to be developed to allow this information to be provided to commercial aggregators.

Without the DSO sharing network information more broadly, there are risks that (a) financially, the DSO-aggregated DER are comparatively worse off; and (b) technically, expected MW delivery from the commercially-aggregated DER does not always materialise, due to unforeseen distribution network capacity issues.

What would this mean for the DSO?

DSOs would need to deliver the intent of any Bid-Offer Acceptances (BOAs) issued to the VPP. Any BOAs to vary the output of the VPP would represent firm energy contracts, and delivery risk would need to be managed by the DSO. Further, the DSO would need a way of managing the imbalance impact of BOAs on Suppliers of the constituent parts of the VPP.

DSOs do not currently interface with the Balancing Mechanism provisions contained within the BSC in a substantive sense. To operate a VPP, the DSO would need to enter into suitable arrangements with Elexon to enable them to become a Virtual Lead Party, the classification of participation that allows operation of aggregated, or 'Secondary BM Units'. In addition to the systems and processes required to facilitate this, the DSO would also need to establish suitable service contracts with DER to enable the operation of the VPP.

Note that the BSC defines a Virtual Lead Party as being a Party who has registered in such capacity, with a Party being defined as someone who is bound by the BSC by virtue of being a party to the BSC Framework Agreement (specified in NGESO's Transmission Licence). DNOs, as Authorised Electricity Operators, are party to the BSC

⁴ Ofgem stated, in their "Enabling the competitive deployment of storage in a flexible energy system: changes to the electricity distribution licence" consultation, that they "...consider that DSO involvement in commercial aggregation risks having a negative effect on that market and undermining the impartiality of the DSOs. As such, we do not believe that this is an appropriate activity for DSOs to engage in."

⁵ Modifications have been proposed to the BSC to simplify this requirement (e.g. [P376](#) – Using a Baseline Methodology to set Physical Notifications for Settlement of Applicable Balancing Services)

Framework Agreement, so there would appear to be nothing in UK legislation that prevents them taking on Virtual Lead Party Status. Whether that is also the case for EU legislation is not clear at this point.

DSOs would need to guarantee that DER within the VPP were GSP-specific, rather than aggregated at GSP Group level, so that NGENSO could be clear on what will happen at the GSP when their output changes. This would include the need to understand and mitigate any risks associated with service non-delivery, as well as understanding broader issues such as the impact of distribution-level interconnection between GSPs.

How would this fit within current charging and access arrangements?

From a transmission perspective, it would be expected that the VPP be treated appropriately in settlement – either via standard BM processes if it were a Secondary BM Unit, or via Balancing Services Adjustment Data if it were treated as an aggregated Balancing Services provider. In both cases, Balancing Services Use of System charges would allow for cost-recovery.

From a distribution perspective, the implications of DSOs operating VPPs for provision of services to NGENSO would need to be worked through, to ensure that distribution charging and access arrangements, and DUoS Charges, remain appropriate.

Conclusions

Objectives	Method 2: DSO operates VPP at the GSP	RAG/ Timescales/ Complexity
Meets NGENSO needs	Allows NGENSO to contract with DER or DSO for provision of NGENSO services from DER Develops the DSO's role in provision of NGENSO services by DER	Green
Meets DSO needs	Allows DSOs to contract with DER for provision of DSO services Represents new capability requirements for DSO	Green
Ease of engagement by DER	Provides clear routes to participation in DSO services, and a further aggregated route to provision of services to NGENSO (in addition to current commercial aggregation service providers) Requirement to engage with two contract counterparties, rather than one, would be efficiently managed	Green
Compatibility with existing wholesale market provisions	DSO provision of aggregation services from DER to NGENSO would be in direct competition to existing commercial aggregation companies and is considered inappropriate by Ofgem	Red
Ease of implementation	Requires new DSO aggregation terms Depending on complexity of distribution network, may require distributed energy resource management system software to facilitate VPP operation	Yellow
Flexibility for the future	Terms established by DSOs for aggregation may be variable to reflect changing circumstances Nothing in the terms would preclude further structural change within the industry, which may render the terms obsolete	Green

Method 3: DSO operates GSP within its technical capability

The aim of this approach would be to allow the DSO to use its understanding of the capability of the distribution network to offer a complete offtake-management service at the GSP. The service would be for both decreases and increases in offtake from the GSP and would also extend to provision of other active and reactive power Balancing Services to NGENSO.

The exact detail of this approach depends on the nature of the GSP under consideration - for example whether the network below the GSP could be considered in isolation, or whether there are interconnections with areas of distribution network fed from other GSPs. The principles, however, would be similar:

- The DSO would procure services from DER to manage MW flows and MVAR levels on the distribution network;
- The DSO would contract with NGENSO to enable delivery of Balancing Services at the GSP;

- The GSP would have a defined MW and MVar capability, within which its assets must be operated. The DSO would keep flows on these assets within limits using tools at its disposal, such as DSO flexibility services, demand transfers, etc;
- To enable national balancing of generation and demand, the DSO would need to forecast the GSP MW flow profile through time (effectively, a GSP 'Physical Notification') and submit this to NGENSO, along with prices and MW capabilities for flow increases and decreases. To support these changes in flow, dynamic parameters, such as rates-of-change of MW, would be required;
- To enable coordinated management of system voltage, the DSO would vary reactive power export/import at the GSP⁶ so that it contributed to an efficient national voltage profile managed by NGENSO, with appropriate static and dynamic reserves to manage voltage changes;
- When needed, NGENSO would instruct the DSO to vary the MW or MVar transfer at the GSP. This could be for several reasons, for example transmission constraint management, voltage management, or energy balancing (DSO systems would facilitate delivery of such services from DER within the GSP, in suitable timescales); and
- NGENSO may also require response or reserve services from DER within a GSP. To facilitate this, the DSO would establish and hold appropriate headroom or footroom at the GSP, so that relevant rates of change of MW/MVar could be accommodated.

As for method 2, the component parts of the of the GSP (i.e. DER; DSR) would continue to participate in wholesale market as normal, so would maintain current relationships with Suppliers, etc. Any instructions from NGENSO to the DSO to vary the flow of active or reactive power at the GSP would represent firm contracts, as is currently the case for NGENSO's balancing services. Delivery risk would therefore need to be managed by the DSO, who would also need a way of managing the imbalance impact of BOAs on Suppliers within the network fed by the GSP.

From NGENSO's perspective, it could be argued that the DSO, in operating a GSP in this manner, is effectively treating the entire distribution network below the GSP as one aggregated BM Unit.

What would this mean for DER?

The implication of this approach would be profound. Although DER within the network fed by the GSP would be able to provide services directly to the DSO, they would no longer have a direct relationship with NGENSO for the provision of balancing services. The DSO would be the sole interface with NGENSO from a balancing services perspective, with the DSO contracting with a range of DER to enable provision of those services. This would require the DSO to act as a neutral facilitator of DER participation in markets for Balancing Services to NGENSO. The DSO would need a means by which it could deliver DER efficient access to those markets where national optimisation determines it would be efficient. This may be contingent on the way network access and charging rules develop.

What would this mean for the DSO?

DSOs would need to deliver the intent of any NGENSO instructions issued to the GSP. Such instructions would represent firm energy contracts, and delivery risk would need to be managed by the DSO. Further, the DSO would need a way of managing the imbalance impact of BOAs on Suppliers of the constituent parts within the GSP.

This would represent a significant move away from current practice and would require a broad range of new capabilities to be established within the DSO, including:

- Generation and demand forecasting: The DSO would need to provide NGENSO with a regular forward-looking forecast of GSP flows, such that it could factor it into its national demand forecast for the purposes of efficient energy balancing and network management;
- Managing wholesale market impact: Instructing DER to deviate from planned output/contract positions will impact their Suppliers' contractual balance. As with current practice for NGENSO services, The DSO will require a means of adjusting the contract positions of the DER's Supplier to reflect the provision of services to either the DSO or NGENSO; and
- Understanding/managing impact of the distribution network paralleling the transmission network - and the effect this has on GSP flows (NGESO will be looking for GSP-level flow control).

⁶ For example, using an approach like that being investigated through the Power Potential NIC project.

To deliver the intent of an instruction from NGENSO, the DSO would dispatch, in cost order and accounting for distribution network capacity, DER to deliver required changes in MW/MVAr at the GSP. In theory, this should allow DER to provide a range of services to NGENSO as well as the DSO, but the DSO would be the sole commercial counterparty, with responsibility for optimising and dispatching DER to meet D and T service needs, and for ensuring DER are clear on what service they are providing to whom.

It could be argued that the characteristics of this approach mean that a formal GSP 'BMU' treatment would be required. This would reinforce the need for appropriate forecasting techniques to manage the submission of physical notification and bid-offer volume data, alongside suitable commercial provisions with DER to enable the formulation of bid-offer prices. The DSO would then need to take on imbalance risk for deviations from its expected T-D flow (as modified by NGENSO instruction) - otherwise there would be no way to distinguish between non-delivery of bids/offers, and PN forecasting errors.

By extension (given the activities the DSO would need to undertake to manage T-D flows), consideration should be given to how this imbalance risk is managed within the GSP itself, such that there are appropriate incentives to minimise it.

How would this fit within current charging and access arrangements?

From a distribution perspective, this would represent a completely new way of working. Existing distribution access and charging arrangements, including those that offer flexible connection arrangements on a 'last in, first off' basis, are likely to require significant evolution from the current approach, such that they provide clear rights of access to both wholesale and system operator service markets (distribution and transmission). In lieu of broader access reform, it may be possible to achieve this by implementing some form of commercial arrangement for distribution network access trading, where DER could modify their position in the LIFO stack to secure more certain access.

There may also be implications for the transmission access and charging arrangements – for example it would also be necessary to evolve the existing BSUoS arrangements (or establish equivalent distribution arrangements) to reflect the cost of activities undertaken by the DSO and to allow for their recovery.

What would this mean for Transparency?

Standard industry processes require NGENSO to categorise and report on the reasons for the balancing actions it takes. This information supports efficient settlement processes (including imbalance cash-out) and reporting on and procurement of Balancing Services. If NGENSO procures Balancing Services from DER via the DSO, it would be necessary for those DER to understand why their services had been bought, and for that reason to be reported by the DSO and treated appropriately. It would be expected that DSOs would need to implement equivalent arrangements for DSO services to those that apply to NGENSO, to deliver efficient market operation.

What would this mean for national optimisation of services?

The expectation here would be that non-locational, energy balancing services, such as frequency response and reserve, would continue to be optimised on a national basis, so that the most cost-effective resources could be utilised. There are several things to consider here, including the following:

- NGENSO has a view currently of services available nationally, either from transmission or distribution connected resources. To efficiently optimise service procurement, NGENSO would need this to continue to be the case for DER service providers, even if it were to have no direct contractual relationship with them (for example via a per-DER, per-service price stack at each GSP);
- NGENSO's decision to instruct a service at a GSP, for example reserve on DER, would be based on a national view of what is available and efficient. Failure of that DER to deliver wouldn't mean that the host DSO would be best-placed to source replacement service provision, as what is available within that GSP may be more expensive than elsewhere; and
- DER providing services to NGENSO via the DSO would need to be clearly identified as such, so that the costs and volumes of service provision could be clearly settled and reported and fed into relevant wholesale market imbalance settlement processes contained within the BSC.

Conclusions

Objectives	Method 3: DSO operates GSP within its technical capability	RAG/ Timescales/ Complexity
Meets NGENSO needs	Allows NGENSO to contract only with DSO for provision of NGENSO services from DER, but the expectation would be that this is appropriately designed	
Meets DSO needs	Allows DSOs to contract with DER for provision of DSO services Represents new capability requirements for DSO	
Ease of engagement by DER	Provides clear routes to participation in DSO services. Expectation would be that NGENSO services could also be accessed, however sole aggregated route to provision of services via the DSO may require additional action by the DSO. Service to NGENSO may not be as competitive if additional DSO overheads need to be recovered	
Compatibility with existing wholesale market provisions	Represents a significant shift from current industry practice Implication for existing frameworks, licences etc would need to be determined	
Ease of implementation	Changes to existing frameworks, licences etc would take time to develop and propose Roles and responsibilities contingent on wider debate New commercial service arrangements would need to be developed Existing DER-Supplier and DER-NGESO relationships would need to be reviewed and changed New IT systems would need to be developed	
Flexibility for the future	Scale of change suggests that this approach would represent a long-term commitment	

4. Summary

Of the three methods presented in this paper, method 2 is considered to be for illustrative purposes only, given that Ofgem have stated they do not consider it an appropriate activity for DNOs to undertake. This leaves methods 1 and 3 as options to enable NGENSO to access services from DER.

It would be expected that both methods 1 and 3 would be designed so that they met the needs of DER, DSOs and NGENSO. It is acknowledged that each method has challenges that need to be worked through, but we believe the magnitude of change associated with method 3 precludes its adoption in the near-term, given the need to develop new DSO capabilities and modify industry licences, rules and frameworks.

However, the activities undertaken within our RDPs to enable further DER connections require us to be able to manage the output of those DER, such that any resulting transmission constraints can be managed efficiently. Without an agreed way forward on commercial access to those DER, there is a risk that further DER connections in constrained areas of the network become contingent on asset build, which would undo the benefit delivered through the RDP process.

It is recommended that method 1 is adopted in the near-term, so that NGENSO can ensure efficient ongoing management of transmission constraints, and access to DER for provision of other services.

We believe that it is possible to progress method 1, to secure NGENSO access to DER in the near-term to support transmission constraint management, and other services, without precluding or undermining transition to an agreed future state further down the line. This view aligns with the conclusion of Baringa's Future Worlds impact assessment⁷, which suggests the continuation of a coordinated approach until certain key trigger points, such as the implementation of reformed access and forward-looking charging arrangements from the early 2020s – at which point, a number of potential DSO transition paths come into play.

⁷ Baringa's Future Worlds impact assessment can be found here:

http://www.energynetworks.org/assets/files/Future%20World%20Impact%20Assessment%20report%20v1.0_pdf.pdf