Informal Consultation Paper

Potential Transmission Charging Arrangements at Exporting Grid Supply Points (GSPs)

GSPs provide the interface between the transmission system and distribution networks. Traditionally they have existed for the purpose of delivery of energy to a distribution network, however because of the growth of generation connected at distribution level increasingly they are also being required to export power onto the transmission network. This may lead to additional investment in transmission infrastructure. This paper considers whether transmission charges should better reflect this impact, and invites views on a number of high level options presented.

Published on: 6th August 2015
Responses by: 31st October 2015

Contents

1 Executive summary

1.1 Introduction

Grid Supply Points (GSPs) provide the interface between the electricity transmission system and distribution networks. Traditionally they have existed for the purpose of delivery of energy to a distribution network, however because of the growth of generation connected at distribution level increasingly they are also being required to export power onto the transmission network. This may lead to additional investment in transmission infrastructure.

Last year there were over 100 GSPs (out of a total of around 350) which exported power onto the transmission system at some point during that year. The level of this export varied dependent on the GSP from those that occasionally spilled to those that exported over most of the year.

Responses to our 2013 informal review of transmission charging arrangements for embedded generation indicated that exporting GSPs was an area of development that may not have been considered when the TNUoS charging methodology was established. Stakeholders suggested that we may wish to further consider whether the TNUoS charging methodology should better reflect the impact of exporting GSPs on transmission investment.

Since the conclusion of this informal review last year we have further analysed, considered and discussed thoughts on potential TNUoS charging arrangements for exporting GSPs. This paper considers whether transmission charges should better reflect this impact, and invites views on a number of high level options presented. This is an informal National Grid consultation and any formal proposal that might arise from this work would be subject to open governance in accordance with the Connection and Use of System Code (CUSC) framework.

1.2 Summary of this document

Section 2 of this paper provides background information to assist those that might not be familiar with the transmission system and associated charges, and also describes in further detail the numbers of exporting GSPs connected to the GB transmission system. Section 3 describes in detail the drivers for our work and invites views. We have also provided a glossary in Section 7 of some industry terms used.

We present two potential options to introduce local TNUoS charges at exporting GSPs in section 4. These are based on a similar rationale as the existing TNUoS local charging methodology for transmission connected generation. We are proposing that only a subset of exporting GSPs with the higher levels of export (numbering around 50 last year) would be affected. The first option considers introducing a local substation charge, and a second option considers both a local substation and local circuit charge (where applicable). This second option would also require, we believe, a change to the charging definition of 'MITS node' to reflect this change to the local charging methodology. At this stage we are proposing that these potential options would not apply to importing GSPs, or those GSPs which export to a lesser degree. It is anticipated that any changes to the TNUoS methodology arising from these potential options would not be implementable before April 2018.

We are also mindful of the future growth in distributed generation as recently evidenced in the 2015 Future Energy Scenarios (FES) document. This may require us to adapt our commercial arrangements to better reflect the impacts of active distribution networks and proportionally lower levels of transmission connected generation. We recognise that this may require a broader level of change to commercial arrangements and we are interested in your views to help shape our next steps in this area. Our initial thoughts and questions are laid out in section 5.

1.3 How to get involved

We are really interested in your views to help shape our next steps. Stakeholders have told us they would like an appropriate consultation period to ensure considered responses can be made. With that in mind we are running this consultation for longer than the standard period and we welcome any views you may have through to 31st October. Details of how to get involved are provided in section 6 of this document, but if you have any questions or thoughts please email Andy Wainwright (andy.wainwright@nationalgrid.com).

2 Background

2.1 What are exporting GSPs?

Grid supply points (GSPs) are traditionally the points where power is delivered from the transmission system to either a distribution network or a customer directly connected to the transmission system. Distribution networks are owned and operated by Distribution Network Operators (DNOs). There are 6 DNOs in GB as shown in Fig.2.1 below and their networks are divided into 14 areas. These areas align with GSP Groups used in the supply of electricity.

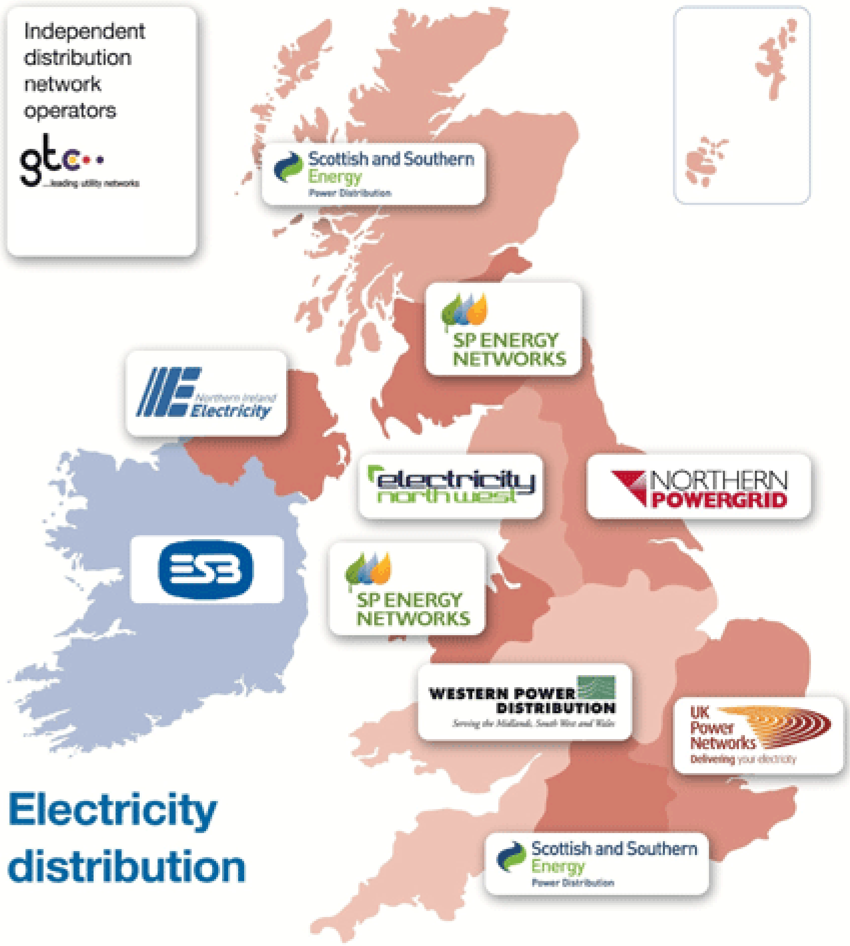

Fig. 2.1 – DNO areas in GB

There are an increasing number of generators connecting directly to these DNO networks. These are referred to as distributed or embedded generation. On some distrbution networks the power output of such generators can be greater than the demand. As a result that distribution network will export power back onto the transmission system at the GSP. This consultation refers to such GSPs as exporting GSPs.

There are a number of ways that we can define a GSP as exporting. These are discussed in further detail below.

2.2 How many exporting GSPs are there?

We have considered metering data from around 350 GSPs across GB for both 2013/14 and 2014/15 to establish the numbers of exporting GSPs on the transmission system. In 2013/14 there were 104 GSPs that exported power to the transmission system in at least one half hourly period (a settlement period). That number rose to 116 GSPs in 2014/15. A breakdown of these numbers by DNO area is given in Table 2.1 below.

DNO	Total No. of GSPs	Export at any time		Max export > max import	
	14/15	13/14	14/15	13/14	14/15
WPD – W Midlands	14	1	1	0	0
WPD – E Midlands	16	0	0	0	0
UKPN - Eastern	20	2	4	0	0
UKPN - London	16	1	1	0	0
UKPN – South East	10	3	3	0	0
Electricity North West	17	6	6	1	1
Northern Powergrid - N	18	4	5	3	3
SPEN - Manweb	13	5	7	0	0
SSEPD - S England	18	1	1	0	0
WPD – South West	9	1	2	0	0
WPD – South Wales	11	3	3	0	0
Northern Powergrid - Y	20	2	2	0	0
SSEPD - N Scotland	69	47	49	32	36
SPEN – S Scotland	84	28	32	11	11
Total	353	104	116	47	51

Table 2.1 – Number of GSPs in each DNO area (GSP Group)

The final columns of data in Table 2.1 relates to a subset of these exporting GSPs; specifically those GSPs which have a higher maximum power export than their maximum power import during that financial year. We believe that this may be a potentially important measure for transmission charging. This is because the TNUoS charging methodology, as described in more detail in section 2.5, is based on a forward looking incremental methodology. So, rather than considering actual future transmission reinforcements, the TNUoS methodology considers an averaged incremental cost of future investment. As network investments are lumpy in nature, this has the benefit of reducing volatility in customer charges. Applying this methodology to exporting GSPs, if a Transmission Owner (TO) were to reinforce for the next incremental MW, then it is those GSPs with a higher export than their import that would be reinforced on the basis of export. There were 47 such GSPs in 2013/14 rising to 51 in 2014/15. There is good consistency between these results, the 51 GSPs being made up of the 47 from 2013/14 and 4 additional GSPs.

Table 2.2 shows further alternative methods for identifying exporting GSPs and the numbers of GSPs for each of these methods. 'Export at peak' refers to those GSPs which were exporting power during any one of the three Triad periods in that year[1]. This could be relevant as metered demand during these periods is used to provide the TNUoS charging base for half-hourly (HH) metered customers. Another potential measure is 'net energy export'. In this option we have considered the net energy being transferred either into or out of a GSP (i.e. export – import) over

[1] Details of the relevant Triad dates can be found on our website; http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Transmission-Network-Use-of-System-Charges/Transmission-Charges-Triad-Data/

the entire financial year, so that only those GSPs which have a net export of energy would be considered as an exporting GSP for charging purposes.

DNO	Total No. of GSPs	Export at peak		Net energy export	
	14/15	13/14	14/15	13/14	14/15
WPD – W Midlands	14	0	0	0	0
WPD – E Midlands	16	1	1	0	0
UKPN - Eastern	20	1	1	0	0
UKPN - London	16	0	0	0	0
UKPN – South East	10	1	0	0	0
Electricity North West	17	2	1	1	1
Northern Powergrid - N	18	3	2	2	1
SPEN - Manweb	13	2	1	0	0
SSEPD - S England	18	1	0	0	0
WPD – South West	9	0	0	0	0
WPD – South Wales	11	0	0	0	0
Northern Powergrid - Y	20	0	0	0	0
SSEPD - N Scotland	69	35	38	24	28
SPEN – S Scotland	84	14	16	7	9
Total	353	60	60	34	39

Table 2.2 – Alternative measures for assessing exporting GSP numbers per DNO area

2.3 What are transmission charges?

There are three main transmission charges. The methodology of their calculation can be found in Section 14 of the Connection and Use of System Code (CUSC)[2].

Connection charges recover the costs of installing and maintaining those assets that allow parties to connect to the transmission system and which are not normally used by any other party. They are recovered on an annual basis, so costs are recovered over the lifetime of the asset. They are site specific relating to the costs of those assets at particular sites such as a GSP.

Transmission Network Use of System (TNUoS) charges recover the cost of installing and maintaining the transmission system in England, Wales, Scotland and offshore. They are paid annually by suppliers, transmission connected generators and some distributed generators. TNUoS charging arrangements are discussed in more detail below as these are the primary focus of this consultation.

Balancing Services Use of System (BSUoS) charges recover the cost of the day to day operation of the transmission system. Suppliers, transmission connected generators and some distributed generators are liable for these charges.

[2] http://www2.nationalgrid.com/The-CUSC/The-Connection-and-Use-of-System-Code/Section-14-–-Charging-Methodologies-v1-10/

2.4 How are transmission charges currently applied at GSPs?

The majority of GSPs provide a connection for a single customer. At such sites sole use assets are categorised as connection assets and their costs are recovered from that single customer as connection charges. In the case of DNOs these costs are then passed on to their customers on a socialised basis as exit charges.

Some GSPs connect multiple parties. At these sites all assets are considered to be part of the infrastructure of the main transmission system. Their costs are recovered through TNUoS charges. Currently these costs are socialised across all parties who pay TNUoS on a capacity basis as part of the DUoS charges on a capacity basis for half hourly metered customers and a commodity basis for non-half hourly metered customers.

2.5 TNUoS charging arrangements

All customers liable for a TNUoS charge pay towards the cost of the main interconnected transmission system (the MITS) through a wider TNUoS charges. This charge is set for customers on a zonal basis and consists of a locational element reflecting the cost a user imposes on the MITS and a residual component to ensure the correct overall amount is recovered through the charges.

Generators, in return for paying their annual TNUoS, receive access rights for that year to use the transmission system up to their commercial capacity known as Transmission Entry Capacity (TEC). These generators are primarily transmission connected although there are a small number of licensable generators with a TEC of over 100MW who are embedded within distribution systems who pay through these arrangements.

Generators also pay local TNUoS charges. All generators pay a local substation charge which reflects the cost of the substation infrastructure they connect into. Additionally some generators are also liable for a local circuit charge which reflects the costs of the circuits used to connect that generator to the MITS. The determination of whether a generator is liable for a local circuit charge depends on whether it connects to a MITS node. The TNUoS charging definition of a MITS node is currently defined as;

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- Connections with more than 4 transmission circuits connecting at the site.

Demand customers are not currently liable for local TNUoS charges.

Both the wider locational and local TNUoS charge elements are based on an approach referred to as 'Investment Cost Related Pricing (ICRP)'. The ICRP methodology considers the existing transmission system and charges on the basis of the averaged impact of an incremental MW on system requirements[3]. An alternate methodology, such as that used in the distribution network charging EDCM methodology (see section 2.6 below), could be based on the future cost of transmission investment, i.e. a Long Run Marginal Cost Methodology (LRMC).

2.6 What are distribution charges?

Customers who connect to a licenced Distribution Network Operator (DNO) system will normally pay a one-off charge for the provision of the connection to the distribution system. This connection charge covers the cost of distribution system assets which are only required for the connection of

[3] Further details of the ICRP methodology can be found in Section 14 of the Connection and Use of System Code (the CUSC); http://www2.nationalgrid.com/The-CUSC/The-Connection-and-Use-of-System-Code/Section-14-–-Charging-Methodologies-v1-10/

the particular customer and (where relevant) a proportion of the cost of any wider system upgrades (reinforcement) needed. The customer normally has the option to undertake some of the connection works ('contestable works') and these are adopted by the DNO upon completion.

Once connected, Distribution Use of System (DUoS) charges are charged by the DNO for the transportation of electricity across the distribution system between the connection and the GSP. The DNO normally levies DUoS charges to each customer's appointed electricity supplier, but in some cases they are charged directly to electricity generators or other parties. The DUoS charges cover the ongoing costs of operating, maintaining, renewing and investing in a safe and reliable distribution system that facilitates the transportation of electricity.

The Common Distribution Charging Methodology (CDCM)[4] is used by all GB DNOs to calculate DUoS tariffs for Low Voltage (LV) & High Voltage (HV) demand and generation connections. In CDCM, exporting LV and HV connected generators are deemed to provide beneficial support to the DNO networks and thus DUoS credits are paid by the DNO in recognition of this. The CDCM is the basis of a range of standard demand and generation tariffs in each DNO area and these have no locational or site-specific elements.

Extra High Voltage (EHV) connections metered at 22kV or above or High Voltage connections which are metered at EHV/HV substations are subject to the EHV Distribution Charging Methodology (EDCM). This is laid out in Schedules 17 and 18 of the Distribution and Connection Use of System Agreement (DCUSA)[5][6]. EDCM DUoS charges are calculated on an individual site-specific locational basis. Generation connections deemed to provide beneficial support to the DNO networks may qualify for DUoS credit payments.

As a transitional arrangement when export DUoS charges were introduced, Ofgem directed that generators which had connections established under 'pre-2005' contractual arrangements could be exempt from export charges for a 25 year period from connection. Currently therefore, a significant proportion of embedded generation in the EDCM category is not subject to export DUoS charging.

[4] http://www.dcusa.co.uk/DCUSA%20Document%20Public%20Version/Schedule%2016%20v7.4.pdf

[5] http://www.dcusa.co.uk/DCUSA%20Document%20Public%20Version/DCUSA%20v7.3%20Schedule%2017.pdf

[6] http://www.dcusa.co.uk/DCUSA%20Document%20Public%20Version/DCUSA%20v7.3%20Schedule%2018.pdf

3 Drivers for our work

There are a number of drivers for our work which are described in further detail in this section. We would be interested in your thoughts on these drivers and whether there are any other reasons for considering potential transmission charging arrangements at exporting GSPs.

3.1 System Operator licence obligations

As the transmission licensee, authorised to co-ordinate and direct the flow of electricity onto and across the transmission system within Great Britain, National Grid has duties under the Electricity Act to develop and maintain an efficient, co-ordinated and economical transmission system and to facilitate competition in generation and supply.

Along with these high level duties, we are obliged under our transmission licence:

(i) to keep the Use of System Charging and Connection Charging Methodologies at all times under review

(ii) to make such modifications of the Use of System Charging Methodology and Connection Charging Methodology as may be requisite for the purpose of better achieving the relevant objectives, which are:

(a) to facilitate effective competition in generation and supply;

(b) to result in charges which reflect, as far as reasonably practicable, the costs incurred by transmission licensees in their transmission businesses;

(c) in so far as is consistent with a) and b) above, as far as reasonably practicable, they properly take account of the developments in transmission licensees' transmission businesses.

(d) for connection charging, in so far as is consistent with a), b) and c) above, of facilitating competition in the carrying out of works for connection to the GB transmission system

In addition to the relevant charging objectives above, the transmission licence (standard condition C7) also prohibits National Grid from discriminating against any User or class of Users unless such different treatment reasonably reflects differences in the costs of providing a service.

If we believe that a change to the way we charge for transmission is required on the basis of improving at least one of points a-d listed above then we will propose a change to the CUSC[7]. Similarly as the CUSC is subject to open governance arrangements, any CUSC Party[8] can similarly propose changes if they believe their proposal better meets at least one of the points a-d listed above. Such proposals are then subject to a formal governance process involving industry stakeholders, prior to an Ofgem determination. This informal consultation is intended to inform any formal CUSC proposal which would then be subject to the formal governance process.

---

[7] The CUSC is the industry code that contains the Use of System Charging and Connection Charging Methodologies.

[8] Ofgem also have the powers to allow non CUSC parties to submit proposals

3.2 Transmission investment including new GSP connections

We are aware of a number of new GSPs that have been connected to the transmission system in recent years. We understand that these GSPs have been developed primarily for the connection of new distributed generation projects. We understand that there are plans for further GSPs to be connected to the GB transmission system for similar reasons. In addition we are aware of a number of GSPs which are requiring increases in transmission capacity to facilitate the connection of distributed generation. All these developments require transmission investment. Other than those assets deemed to be connection (see section 2.4) the cost of these investments is borne by TNUoS charge payers, rather than the parties driving the investment.

The connection of these generation projects to a distribution network and the resultant requirement for transmission investment may be the most efficient solution for the GB consumer. Indeed all network companies have in place licence requirements to ensure efficient system development. However where options exist to connect parties at either a transmission or distribution voltage, the process is currently reliant on the level of co-operation between network companies. Whilst we do not doubt that such co-operation exists and there are many good examples where this had led to least cost solutions for the GB consumer, a charging signal to a party of the cost of an investment option could assist efficient development. We believe that, as the party responsible for the application of the request for a new, or developing, GSP, a DNO becomes the natural choice for such a charging signal.

3.3 Stakeholder feedback

In 2013 we published an informal consultation to review the embedded (distributed) generation benefit arising from transmission charges[9]. We invited views from stakeholders on a number of potential options for changing the way the TNUoS charging methodology reflected the impact of distributed generation on transmission investment and received 33 responses which are now published on our website[10]. One of these potential options focused on how to better reflect the impact of exporting GSPs on transmission investment. This area had arisen in external focus group discussions as stakeholders had considered the embedded benefit was, in part, justified through the reduction in the need for transmission infrastructure investment. Those stakeholders suggested that, at exporting GSPs, if there was an increased requirement for investment then maybe the TNUoS charging methodology could be changed to better reflect this investment driver.

Many consultation respondents considered that this was an area of increasing significance that could be better reflected in the TNUoS charging arrangements. However many believed that further development in this area was required before a formal CUSC modification proposal could be defined. This consultation intends to lay out such further development.

3.4 Treatment of infrastructure assets

Connection assets are those assets that allow parties to connect to the transmission system and which are not normally used by another party. The cost of connection assets are recovered through connection charges. All other transmission assets are categorised as infrastructure assets and their costs are recovered through TNUoS charges.

---

[9] http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=29996

[10] http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Transmission-Network-Use-of-System-Charges/Embedded-Benefit-Review/

The majority of transformers at GSPs are categorised as connection assets as they are used by a sole party (the local DNO). However there are a number of GSPs which are used for the connection of more than one party. This could be because there are multiple DNOs at the GSP, or because the GSP supplies a DNO and a generator. At these sites transformers are categorised as infrastructure assets as they are shared. The costs of infrastructure SGTs are currently socialised in the TNUoS charging methodology and effectively recovered via the residual element of the TNUoS tariff.

There is therefore a difference in the transmission charging treatment of transformers, and other associated assets, between those designated as connection and those designated as infrastructure. This presents the potential for step changes in charges, and indeed charge payers, if assets are recategorised from connection to infrastructure. This could even provide an incentive to a user to seek to recategorise charges from connection to infrastructure.

3.5 Growth in distributed generation and impact on system operation

The volume of distributed generation connected is predicted to increase. The 2015 Future Energy Scenarios (FES)[11] considered a growth in small scale generation (distributed and micro-generation) connected by 2020 in all its scenarios. Even the most modest scenario, No Progression, indicated a growth of around 8GW of such generation by 2020.

With the continued growth of such generation it follows that the number of exporting GSPs is likely to increase. We have used the forecast data provided in the FES to estimate the potential increase in the number of exporting GSPs. Whilst we have been able to assess growth levels in regional zones to a greater granularity than DNO areas, our analysis should only be treated as illustrative rather than any future forecast. This is consistent with the level of information available such as the specific location of this generation, and also the net nature of the metering data we have which makes it difficult to account for future demand trends in the analysis.

Figs. 3.1 and 3.2 below show illustrative ranges of exporting GSP growth for both the 'Export at Any Time' and 'Max Exp > Max Imp' methods for identifying exporting GSPs and are based on the same 2014/15 metering data as that used to derive the figures in Table 2.1. Ranges are shown for both 2020 and 2030 for each of the FES scenarios (No Progression, Slow Progression, Gone Green and Consumer Power) with central case values indicated.

This increase in distributed generation presents a number of challenges in operation of the GB transmission system. Ultimately this may mean an increased level of active involvement with distributed generation to balance the system. This could be directly with such generation, but may be through a third party aggregator such as a DNO or Supplier. Commercial arrangements could need to evolve to facilitate such a change. We are interested in your views as to the future commercial arrangements that could be required to facilitate such developments.

Q3.1 What are your thoughts on the drivers for our work?

[11] http://fes.nationalgrid.com/

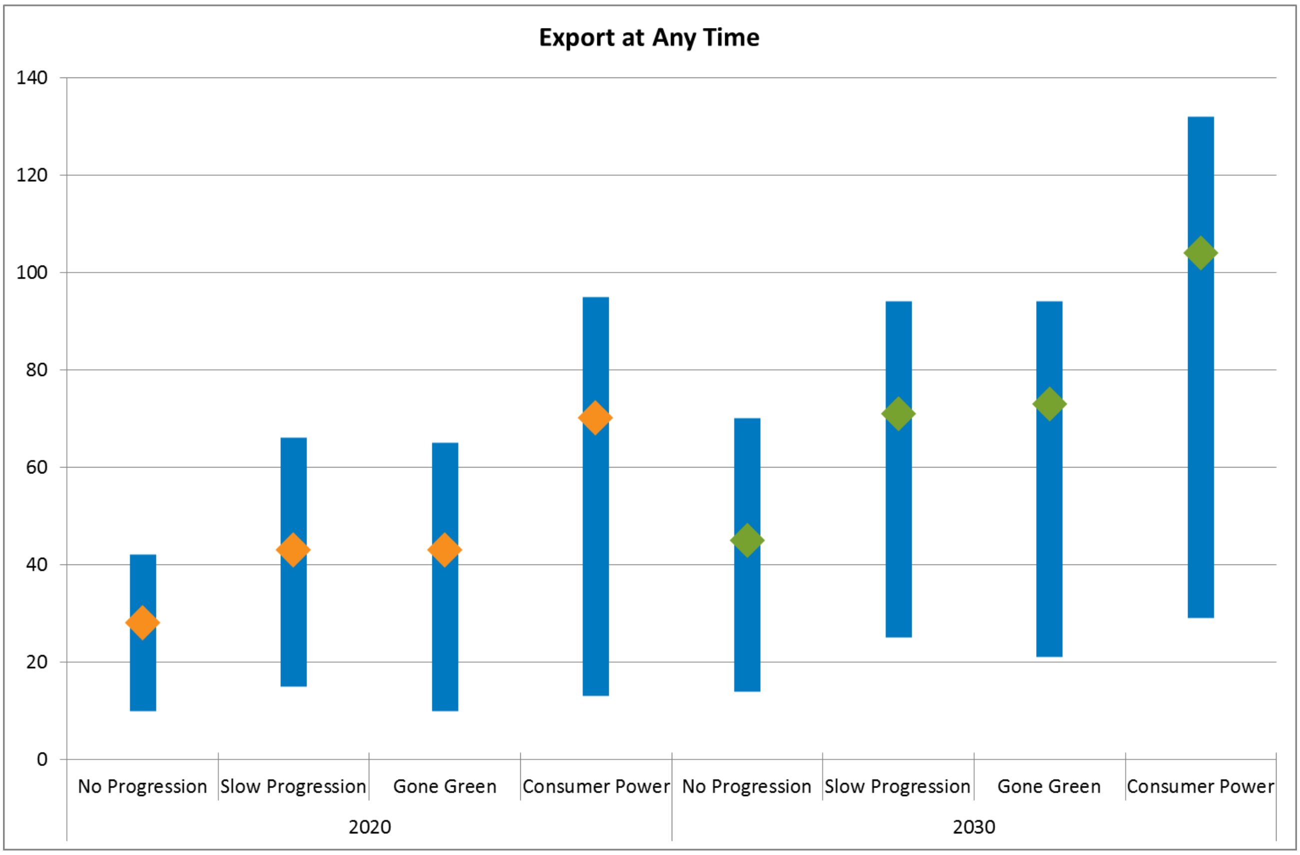

Fig.3.1 – Illustrative ranges of exporting GSP growth for those GSPs which export in any settlement period during a year

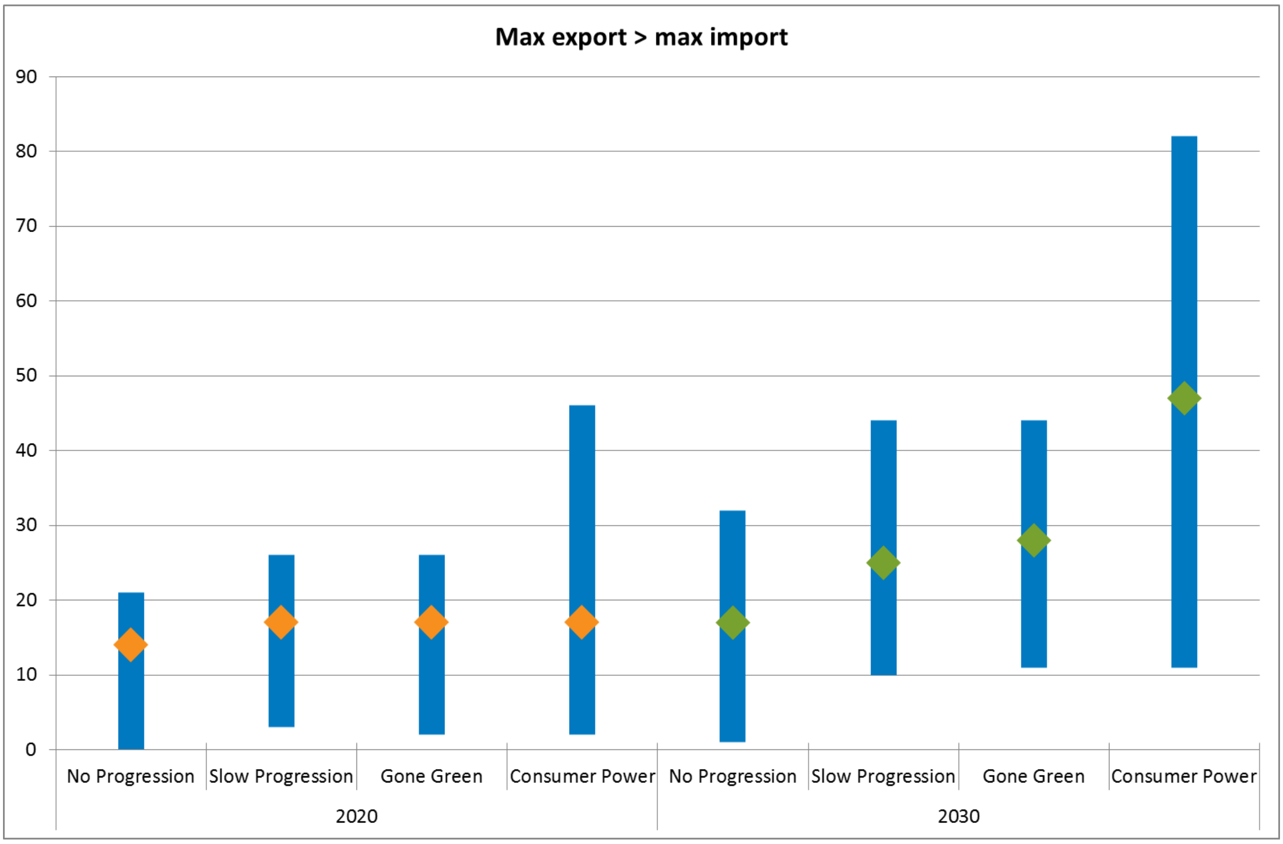

Fig.3.2 – Illustrative ranges of exporting GSP growth for those GSPs whose maximum power export in any settlement period exceeds their maximum power import in any settlement period

4 Local TNUoS charging options

4.1 Introduction

This section considers some options that could be taken forward within the next three to four years to potentially better reflect the costs of transmission investment driven by GSPs which export power onto the transmission system.

These options consider that an exporting GSP behaves in a similar manner to a generator exporting power onto the transmission system and should therefore be exposed to a similar level of TNUoS charge. These options consider extending the local TNUoS charging arrangements to exporting GSPs on this basis.

We have not considered extending these arrangements to importing GSPs at this time. This is consistent with the current TNUoS local charging philosophy which charges generators a local substation and circuit charge (where applicable) but not demand users. This is because we believe that it is appropriate that circuits which connect remote communities to the transmission system should not bear the cost of that local connection. We are also mindful of comments to our wider review of transmission charging arrangements for embedded generation which suggested that the presence of distributed generation within an importing GSP would reduce the need for transmission investment.

Q4.1 Do you agree that any local TNUoS charging option should be limited to those GSPs which export power onto the transmission network?

In this section we lay out the principles underpinning the potential options before describing the potential options and providing illustrative examples.

4.2 Principles

These local charging options would reflect the incremental cost of an exporting GSP on local transmission infrastructure. Cognisant of this we have developed these options with a number of principles.

4.2.1 The Appropriate Party Liable for the Charge

We believe that there may be a number of options for the appropriate party liable to pay a TNUoS local charge. The strawmen options considered in this section are based on the DNO being the appropriate party. This is because the DNO is the party that National Grid has a contractual relationship with at that GSP and also because the DNO is the party with responsibility for co-ordinating net power flows at the GSP. In effect, from a transmission perspective, these local charges would then be treated in a similar manner to transmission connection charges. We do note however that this would require consequential changes to DNO framework arrangements, and the current exemptions that some distribution generators have from DUoS charges.

An alternative arrangement could consider an alternative aggregator such as a Supplier however National Grid does not currently have a contractual arrangement with these parties at a GSP level. Also there will potentially be many Suppliers involved at each GSP so there may be limited ability for a Supplier to efficiently respond to a TNUoS signal

Thirdly a commercial framework could be developed directly between National Grid and an increased number of distributed generators. Currently we have commercial agreements with a number of distributed generators. These are primarily large generators with either Bilateral Embedded Generation Agreements (BEGAs) or Bilateral Embedded Licence Exempt Large Agreements (BELLAs), although some smaller generators may have BEGAs if they require[12]. Local TNUoS charges could be extended to these generators or potentially to generators which National Grid does not currently have a commercial agreement with. Prospective new generators would then directly receive a financial signal of the impact of their development on future transmission investment.

Q4.2 Who do you believe is the appropriate party liable for a potential TNUoS local charge?

4.2.2 Potential Options for the Charging Base

These local charging options would reflect the incremental cost of an exporting GSP on local transmission infrastructure. Cognisant of this we have considered which GSPs trigger transmission investment for export and how a stable charging base could be introduced.

We believe that only those GSPs which would be reinforced on an incremental basis should be liable for the charge. That is those GSPs with a higher maximum export than their maximum import. At this time it is anticipated that these would be calculated based on metered data. Alternatively forecast data such as that provided by DNOs to National Grid under current Grid Code requirements (week 24 data) could potentially be used. Current numbers and locations of such GSPs are shown in Table 4.1 below.

Q4.3 What are your views on using historic metering data to determine the charging base?

DNO	Total No. of GSPs	Max export > max import	
	14/15	13/14	14/15
WPD – W Midlands	14	0	0
WPD – E Midlands	16	0	0
UKPN - Eastern	20	0	0
UKPN - London	16	0	0
UKPN – South East	10	0	0
Electricity North West	17	1	1
Northern Powergrid - N	18	3	3
SPEN - Manweb	13	0	0
SSEPD - S England	18	0	0
WPD – South West	9	0	0
WPD – South Wales	11	0	0
Northern Powergrid - Y	20	0	0
SSEPD - N Scotland	69	32	36
SPEN – S Scotland	84	11	11

[12] Further information on commercial arrangements for distributed generation can be found in this Elexon guidance note; https://www.elexon.co.uk/wp-content/uploads/2013/11/embedded_generation_embedded_benefits_v6.0_cgi.pdf

Table 4.1 – Number and location of exporting GSPs considered until TNUoS local charging options

We are mindful that a small increase in the level of distributed generation output within a GSP could result in a GSP becoming categorised as an exporting GSP for charging purposes. To ensure stability in the approach we consider that the charging base for the GSP should be the difference between the GSP's maximum export and its maximum import. This would mean that a GSP that became an exporting GSP for charging purposes would then only receive a relatively small charge reflecting this incremental change in its output. For example a GSP with a peak import of 75MW and a peak export of 80MW would be charged based on 5MW. Our analysis of 2014/15 metered data is that this difference for most GSPs is less than 25MW.

Q4.4 Do you have any comments on this approach to the potential calculation of a charging base for these options?

4.2.3 Proposed treatment of infrastructure transformers at GSPs

Infrastructure GSPs are those GSPs with a number of customers connected, i.e. the supply point and connecting assets are shared between a number of users. Currently the cost of transformers supplying such GSPs is socialised through the TNUoS residual charge. The local strawman options propose that these costs would be treated in a similar manner to other local substation costs at an exporting GSP, through a local tariff referred to as a 'local transformer tariff'.

The summated metered output of all parties would be used to identify those GSPs which would be charged local charges based on export. This is because it is the summated effect of all parties giving rise to the need for investment in local substations and circuits. Using this approach there is only one infrastructure GSP in England and Wales that would be liable for this charge and none in Scotland.

The charge would be allocated between each user based on their maximum export in any settlement period in the previous financial year. In the event that a party did not export their proportion of the charge would be zero. For transmission connected generators connected directly onto the low voltage busbars of the substation (i.e. not through an intermediary DNO system) their TEC would be used.

We have calculated indicative local transformer tariffs based on the Gross Asset Values of transformers presented in Appendix 1 of the current Statement of Use of System Charges[13]. These are presented below in Table 4.2. At GSPs with only one transformer a security factor of 1.0 would be used reflecting the lack of redundancy.

Transformer voltage	400/132	275/132	275/132	132/33
Gross Asset Value	5044.0	4410.0	4410.0	1949.0
Capacity	240	240	180	90
Security Factor	1.8	1.8	1.8	1.8
Local Transformer Tariff (£/kW)	£2.88	£2.52	£3.36	£2.97

Table 4.2 - Indicative local transformer tariffs

As an example consider the following GSP referred to as GSP X. GSP X connects two DNOs; DNO A and DNO B to the transmission system. The maximum export at GSP X (75MW) occurred

[13] http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=40130

on 31/03/15 at 01:00hrs. At that time the net flow on DNO A circuits was an export of 100MW and the net flow on the DNO B circuits was an import of 25MW.

The maximum export on the DNO A circuits was 100MW and occurred at this time. The maximum export on the DNO B circuits was 25MW and occurred at 06:00hrs on 06/08/14.

The charging base for the local substation and SGT charges is 75MW (i.e. maximum net export). 80% of this charge is paid by DNO A and 20% by DNO B reflecting the level of export on each of their distribution networks.

Q4.5 Do you have any comments on our proposed approach to transformers at shared exporting GSPs?

4.2.4 MITS node definition

Local circuit charges for transmission connected generators are charges reflecting the incremental impact of a generator on the local circuits connecting it to the nearest MITS node(s). A MITS node for TNUoS charging purposes is currently defined as;

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- Connections with more than 4 transmission circuits connecting at the site.

This definition does not specifically account for exporting GSPs. If an exporting GSP is considered as similar to a transmission connected generator, whose presence is not recognised in the current MITS node definition, then it follows that the MITS node definition should be re-considered. We believe the following definition may be appropriate to be used with option 2 below;

- connections with 2 or more transmission circuits and an importing GSP[14] connecting at the site; or
- connections with more than 2 transmission circuits and a GSP connecting at the site; or
- connections with more than 4 transmission circuits connecting at the site.

We believe that this definition accommodates exporting GSPs whilst not changing arrangements for existing transmission connected generators.

Fig. 4.1 below gives some example illustrations in red of circuits that would be categorized as local under this proposed definition for those exporting GSPs (identified by the red arrows).

[14] An importing GSP is a GSP not considered to be exporting for the purposes of transmission charging (i.e. for these strawman options those GSPs with a power import greater than their maximum power export within a financial year).

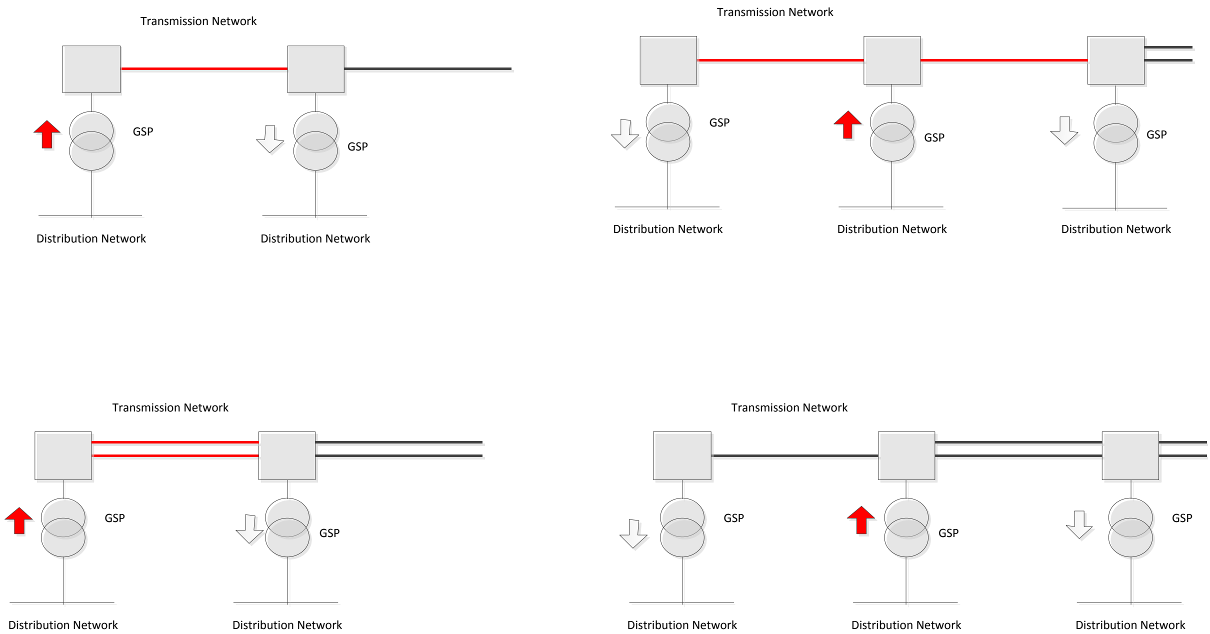

Fig.4.1 – Illustrative examples of potential local circuits

Q4.6 Do you have any comments on the potential change to the MITS node definition?

4.3 Option 1 – Local substation charges

Currently we understand that some distributed generators receive an embedded benefit from their electricity supplier. This benefit arises from the netting of their output with system demand, and arguably reflects the offsetting of additional transmission infrastructure costs at GSPs. It would follow that an exporting GSP should therefore be charged for this cost as it is not offsetting the need for transmission investment at that GSP.

Transmission connected generators pay local substation charges based on a tariff reflecting the nature of the substation they connect into. The current local substation tariffs are shown in Table. 4.3 below;

		Local Substation Tariff (£/kW)		
Sum of TEC at connecting Substation	**Connection Type**	**132kV**	**275kV**	**400kV**
<1320 MW	No redundancy	0.179739	0.102822	0.074085
<1320 MW	Redundancy	0.395951	0.244977	0.178168
>=1320 MW	No redundancy	-	0.322393	0.233156
>=1320 MW	Redundancy	-	0.529287	0.386336

Table 4.3 – 2015/16 TNUoS local substation tariffs

This option would extend this relationship to exporting GSPs and would be based on the high voltage (HV) (i.e. transmission) side of the GSP. GSPs with HV double busbars would be considered to have 'redundancy' whilst those with HV single busbars would have 'no redundancy'. For example, using the figures in Table 4.3 an exporting GSP with a single 132kV busbar connecting to a 33kV distribution network would be liable for a charge based on a tariff of £0.179739/kW.

In addition, under this potential option, at shared exporting GSPs where transformers are treated as infrastructure assets an exporting GSP would be liable for a 'local transformer tariff' such as those described in Table 4.2.

Q4.7 What are your views of potential local TNUoS charging option 1?

4.4 Option 2 – Local circuit and substation charges

Transmission connected generators pay a local circuit charge if they are deemed to have local circuits connecting them to the MITS. Additionally all transmission connected generators pay local substation charges. This option would propose to extend these relationships to exporting GSPs and would also include a 'local transformer tariff' at shared exporting GSPs as described in section 4.2.3.

Not all exporting GSPs would qualify for a local circuit charge as some would connect directly into MITS nodes. The size of the local circuit tariff also depends on the nature and length of the local circuits (i.e. whether the circuit is comprised of cable or overhead line and the voltage of the circuit). Current local circuit tariffs for transmission connected generators are presented below in Table 4.4 Using this proposed approach local circuit tariffs for exporting GSPs would be of a similar range including negative tariffs where the GSP offsets the need for additional transmission investment.

Substation Name	(£/kW)	Substation Name	(£/kW)	Substation Name	(£/kW)
Achruach	3.839934	Didcot	0.225370	Kilmorack	0.176802
Afton	2.080824	Dinorwig	2.152153	Langage	0.589396
Aigas	0.585505	Dumnaglass	3.240647	Lochay	0.327603
An Suidhe	2.734127	Dunlaw Extension	1.310271	Luichart	1.017407
Arecleoch	0.292022	Edinbane	6.128902	Marchwood	0.341907
Baglan Bay	0.664164	Fallago	0.970208	Mark Hill	-0.783834
Black Law	0.895129	Farr Windfarm	2.143727	Millennium Wind	1.455406
Blacklaw Extension	1.965617	Ffestiniogg	0.226870	Mossford	3.549527
Brochloch	1.919139	Finlarig	0.286652	Nant	-1.100208
Carraig Gheal	3.937977	Foyers	0.684073	Neilston	2.135568
Carrington	0.003283	Glendoe	1.646704	Rocksavage	0.015815
Clyde (North)	0.098177	Glenmoriston	1.182403	Saltend	0.298508
Clyde (South)	0.113537	Gordonbush	1.161867	South Humber Bank	0.754716
Corriegarth	2.269208	Griffin Wind	1.674516	Spalding	0.272102
Corriemoillie	2.461327	Hadyard Hill	2.477904	Strathy Wind	4.299193
Coryton	0.050241	Harestanes	4.781432	Whitelee	0.095010
Cruachan	1.591757	Hartlepool	0.530236	Whitelee Extension	0.264128
Crystal Rig	0.365898	Hedon	0.175418		
Culligran	1.551601	Invergarry	1.269646		
Deanie	2.549059	Kilbraur	1.034576		
Dersalloch	1.590028	Killingholme	0.271148		

Table 4.4 – 2015/16 TNUoS local circuit charges

Q4.8 What are your views of potential TNUoS charging option 2?

4.5 Implications on other codes and arrangements

These potential options consider changes to the transmission charging methodologies by widening the scope of local TNUoS charging arrangements. It is proposed that these costs be passed onto the DNOs.

Currently DNOs are liable for transmission connection charges at GSPs. We understand that these connection charges (referred to as exit charges) are passed onto demand customers on a socialised basis by DNOs. It is conceivable that local charges for exporting GSPs could be passed on through similar arrangements, although we understand that this may require licence changes for the DNOs.

We believe that the costs should be borne by the party who can respond to the charging signal. We do not therefore believe that the socialisation of an exporting GSP charge across the entire charging base of a DNO would be appropriate. However we understand that the treatment of resultant distribution charges is a ultimately matter to be considered as a potential change to the DNO commercial framework, the DCUSA.

Q4.9 Do you have any comments on potential options for a recovery mechanism for any local TNUoS charge passed through to a DNO?

5 Longer term commercial arrangements

5.1 Introduction

In section 3.5 we discussed the increasing penetration of distributed generation, including micro-generation and indicated a potential need to change our commercial arrangements to better reflect the impact of these new generators on the GB transmission system and more widely the energy market. We are conscious that such a move would require broader reform potentially taking a significant amount of time to implement. However we are interested in your views to help shape our next steps in this area.

In regard to electricity production, the transmission charging and access arrangements have been developed primarily to facilitate the connection and access of transmission connected generation. Large generators pay an annual TNUoS charge which guarantees their access to the transmission system and therefore the wholesale market for electricity. They then also bear their share of the operational costs incurred balancing the transmission system through BSUoS charges, and may also receive payments if we require services from them in this regard. Smaller generators do not pay such charges and generally are not called upon to provide services. This section considers whether these arrangements remain appropriate and poses some questions that we would appreciate your thoughts to help shape our broader strategy in this area.

5.2 Implications for commercial operation of the system

As the proportion of distributed generation grows larger we will increasingly need to explore options to efficiently balance the system using services procured from distributed generation. Current BSUoS arrangements mean that whilst we may ask and remunerate distributed generation for their services, they will not pay towards the cost of operating the system. Introducing commercial arrangements with these generators may also mean we can better access their services providing a more efficient solution for the end consumer. Further it may be that other parties, such as responsive demand, can similarly provide services and we are interested in your views as to how these arrangements could be better facilitated?

Q5.1 Do you believe current BSUoS arrangements are appropriate if parties who do not pay BSUoS are driving costs to the System Operator in managing the system and if we procure services from these parties?

Q5.2 Do you believe we should be looking at options to introduce further commercial arrangements with both distributed generation and responsive demand or are there any alternative arrangements we should consider?

The initial options proposed in section 4 put forward the DNO as an appropriate aggregator for a local TNUoS charge at an exporting GSP. This is because a DNO is the contractual party at a GSP and together with National Grid is responsible for the physical management and operation of that GSP. Going forwards distribution networks will become more active and the need for a Distribution System Operator (DSO) may become more apparent. A DSO may be an appropriate party to assist in the procurement of balancing services from distributed generation. However it may be more efficient to go directly to the distributed generators or through another aggregator; an electricity supplier or some other counterparty. It may be that the efficient solution is a combination of parties.

Q5.3 Who do you believe could be an efficient party to assist in the procurement of balancing services from distributed generation?

Q5.4 Do you believe our thoughts should be limited to models considering an aggregator at this time?

5.3 Implications for TNUoS charges

Section 2.5 of this consultation provides background on TNUoS charges and the options presented in section 4 relate to changes that could be made to TNUoS local charges to better reflect the impact of exporting GSPs. The relationship between distributed generation and wider TNUoS charges was also explored in our 2013 consultation reviewing the embedded (distributed) generation benefit arising from transmission charges. We noted in this informal consultation that distributed generation effectively receives a wider locational signal through their netting with demand users within a GSP group. Hence in the south of England where demand charges are higher, the embedded benefit is higher for generation.

TNUoS charges also confer access rights for large generators to use the system. If distributed generators are increasingly spilling output onto the transmission system, and if they are providing balancing services, it could be argued that they should similarly pay for access rights. Also, as discussed in section 5.2, responsive demand may also require more appropriate treatment.

Q5.5 Do you believe wider TNUoS arrangements should be reviewed to more appropriately account for distributed generation and responsive demand?

Q5.6 Do you believe the potential local TNUoS charging options (laid out in section 4) help move arrangements towards those required in the future?

Q5.7 Do you believe we should be considering any other changes to transmission arrangements to facilitate access to services from distributed generation and responsive demand?

6 How to get involved

This is an informal consultation of potential options for TNUoS charging arrangements at exporting GSPs. It is intended to be used to facilitate discussion and we are really interested in hearing your views on the points raised in this paper. At the request of stakeholders we have specifically lengthened the consultation period to capture as many views as possible. These will be used to help us shape any detailed proposal in this area. If you would like to discuss further any of the points raised please contact Andy Wainwright (andy.wainwright@nationalgrid.com).

To assist you forming views we have posed a number of questions in this consultation. These are listed below and we welcome responses by 31st October 2015. Please email your responses to: dave.corby@nationalgrid.com.

Drivers for our work

Q3.1 What are your thoughts on the drivers for our work?

Local TNUoS charging options

Q4.1 Do you agree that any local TNUoS charging option should be limited to those GSPs which export power onto the transmission network?

Q4.2 Who do you believe is the appropriate party liable for a potential TNUoS local charge?

Q4.3 What are your views on using historic metering data to determine the charging base?

Q4.4 Do you have any comments on this approach to the potential calculation of a charging base for these options?

Q4.5 Do you have any comments on our proposed approach to transformers at shared exporting GSPs?

Q4.6 Do you have any comments on the potential change to the MITS node definition?

Q4.7 What are your views of potential local TNUoS charging option 1?

Q4.8 What are your views of potential TNUoS charging option 2?

Q4.9 Do you have any comments on potential options for a recovery mechanism for any local TNUoS charge passed through to a DNO?

Longer term commercial arrangements

Q5.1 Do you believe current BSUoS arrangements are appropriate if parties who do not pay BSUoS are driving costs to the System Operator in managing the system and if we procure services from these parties?

Q5.2 Do you believe we should be looking at options to introduce further commercial arrangements with both distributed generation and responsive demand or are there any alternative arrangements we should consider?

Q5.3 Who do you believe could be an efficient party to assist in the procurement of balancing services from distributed generation?

Q5.4 Do you believe our thoughts should be limited to models considering an aggregator at this time?

Q5.5 Do you believe wider TNUoS arrangements should be reviewed to more appropriately account for distributed generation and responsive demand?

Q5.6 Do you believe the potential local TNUoS charging options (laid out in section 4) help move arrangements towards those required in the future?

Q5.7 Do you believe we should be considering any other changes to transmission arrangements to facilitate access to services from distributed generation and responsive demand?

Please note that information provided in response to this consultation may be published on National Grid's website unless the response is clearly marked "Private & Confidential". Evidence presented in a response marked "Private and Confidential" may not be able to be used to support a CUSC modification proposal. An automatic confidentiality disclaimer generated by your IT System will not in itself, mean that your response is treated as if it had been marked "Private and Confidential".

7 Glossary

The following terms are used within this report and this glossary is provided to aid the reader. It has been written as a guide rather than a set of formal definitions.

BSUoS: Balancing Services Use of System. These charges recover the cost of the day to day operation of the transmission system. Suppliers, transmission connected generators and some distributed generators are liable for these charges.

CDCM: The Common Distribution Charging Methodology (CDCM) is the Distribution Use of System (DNUoS) charging methodology for low voltage and some high voltage customers. It was approved by Ofgem in November 2009.

CUSC: The Connection and Use of System Code (CUSC) is the contractual framework for charging and connection to, and use of, the transmission system. It is subject to open governance arrangements meaning any CUSC party can propose a change. Ofgem can also allow non CUSC parties to submit change proposals.

DNO: A Distribution Network Operator (DNO) is the industry party responsible for the planning operation and maintenance of distribution networks. In Scotland, distribution networks are at voltages below 132kV, but generally in England and Wales onshore132kV systems are considered to be distribution networks also.

EDCM: The Extra High Voltage Distribution Charging Methodology (EDCM) is the Distribution Use of System (DNUoS) charging methodology for some high voltage and extra high voltage customers. It was approved by Ofgem in April 2012.

GSP: A Grid Supply Point (GSP) is the point at which electricity is transferred from the GB transmission system to a DNO's network or directly to a transmission connected load.

GSP Group: This is the zonal charging base for TNUoS demand customers. A GSP Group consists of a number Grid Supply Points (GSPs). There are currently fourteen GSP groups in England and Wales which are analogous to DNO areas.

HH demand: HH demand is that demand metered on a half-hourly basis.

Licensable Generators: Those generators requiring a generation licence. Licensable generators with a capacity greater than 100MW are required to pay TNUoS charges.

MITS: the Main Interconnected Transmission System.

NETS SQSS: The National Electricity Transmission System Security and Quality of Supply Standards (NETS SQSS) sets out the criteria (both onshore and offshore) used in the planning and operation of the transmission system.

NETSO: The NETSO (National Electricity Transmission System Operator) is the industry party responsible for the operation of the overall transmission system. This is currently National Grid.

NHH demand: NHH demand is that demand which is not metered on a half-hourly basis.

TEC: The TEC (Transmission Entry Capacity) of a generator is the commercial capacity of that generator required to give it access to the transmission system and to allow it to participate in the wholesale market. TEC is used as the chargeable capacity of a generator for TNUoS charging purposes.

TNUoS: Transmission Network Use of System (TNUoS). These charges recover the cost of installing and maintaining the transmission system in England, Wales, Scotland and offshore

TO: A transmission owner (TO) is the industry party responsible for the construction and maintenance activities of a transmission network. TNUoS charges recover the allowed revenues of all onshore and offshore TOs.

Triad: The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak demand and the two half hour settlement periods of next highest demand, which are separated from the system peak demand and from each other by at least 10 clear days, between November and February of the financial year inclusive. The Triad is used as the TNUoS demand charging based for half-hourly demand.