



Bringing Energy
Together

Response to consultation on Potential Charging Arrangements at Exporting GSPs

31 October 2015

Context

The Association for Decentralised Energy welcomes the opportunity to respond to the consultation on a review of the Feed-in Tariffs scheme.

The ADE is the UK's leading decentralised energy advocate, focused on creating a more cost-effective, efficient and user-orientated energy system. Our members have particular expertise in combined heat and power, district heating networks and demand side energy services, including demand response. The ADE has more than 100 members active across a range of technologies, and they include both the providers and the users of energy.

Consultation questions

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

We are supportive of the principle of developing charging arrangements for exporting GSPs where there is a cost impact on the network.

It is important, however, to link between the application of a charge on exporting GSPs and National Grid's previous proposals to move to remove the Embedded Benefit by charging the demand half hourly residual on a gross basis. By implementing a charging arrangement for exporting GSPs, National Grid is effectively addressing the cost impact of distributed generation onto the transmission network, and therefore negating any current perceived need to remove the Embedded Benefit through gross charging.

We would welcome more detail about how exporting GSPs impact the cost of transmission network infrastructure to ensure that any changes are appropriately cost-reflective.

We would further note that National Grid's analysis does not specify how long the periods are during the year that export is greater than import. The length of the period is very important as it changes whether the appropriate signal should be directed at capacity or at market flexibility. For example, if max export is greater than max import for very short periods, the appropriate cost-effective response may be focussing on market signals that reduce output within that GSP during specific periods.

It is our understanding, based on conversations with National Grid, that the periods where max export is greater than max import are not during peak demand periods but potentially instead during low demand periods. Further detailed evidence on this point would be useful to ensure the regulatory response is most effectively aimed at mitigating the potential cost impact of exporting GSPs.

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

Yes. To be more precise, only GSPs which export power onto the transmission network and have a net cost impact on the transmission network should be charged.

It may make sense to apply one rule to all GSPs across the transmission network, than apply the relevant charge when GSPs have a net export onto the transmission network greater than a net import. This would avoid attempting to create different regulatory treatment for different GSPs.

The consultation document does not address the potential treatment of exporting GSPs in a negative charging zone. Such export may alleviate wider transmission network costs, similar to the impact of a transmission-connected generator. While this is unlikely in the near term, with most exporting GSPs located in areas of low demand, charges to exporting GSPs should reflect regional and locational signals in line with transmission-connected generators, which could result in net payments to exporting GSPs where appropriate.

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

We have concerns that National Grid's preference for applying the charge to DNOs will reduce the ability for market participants to react to short-term signals and prevent the additional infrastructure, raising overall costs for consumers.

If max exports are greater than max imports for only short periods during the year, a DNO is not currently able to send appropriate market signals that will allow such periods to be avoided. While this may change in time with several distribution networks considering 'active management' approaches through the Low Carbon Network Fund, they are not currently available.

Applying the charge to suppliers could allow the National Grid settlement system to identify the volume of an individual supplier's offtake from embedded generators under any one GSP Group. If their offtake occurs during a period in which GSPs are exporting, then the suppliers could be liable for the export charge. Such an approach may not be cost-effective to implement in practice, but as it would enable the right market signals to be delivered and acted upon, we would welcome an opportunity for it to receive further consideration.

Whichever approach is taken, the key is that the approach looks to embrace and support market signals for flexible solutions that reduce, prevent and avoid the infrastructure impact of potentially exporting GSPs.

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

We recognise the positive and negatives of both approaches, but would generally support the use of historic metering data to determine the charging base, updated annually, as we expect accurate forecasts a year ahead of the amount of net export from a GSP may be too challenging.

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

We strongly support a 'net basis' for determining the charging base, as it is only the net export which has a cost impact on the transmission system. However, further information is necessary to understand the cost impact of net exporting GSPs on the transmission network.

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

No.

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

While we support the principle that exporting GSPs should be charged in the same manner as a transmission-connected generator, changes to the MITS node definition would have consequences that go beyond charging arrangements. Therefore, the full implications of such a change should be considered carefully with industry to ensure they are implemented appropriately.

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

The ADE has no comment on a preferred charging option, but agrees that an exporting GSP should be charged for any additional transmission infrastructure costs.

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

The ADE has no comment on a preferred charging option, but agrees that an exporting GSP should be charged for any additional transmission infrastructure costs.

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

Without knowledge of how DNO's would pass charges on to connected parties it is difficult to accurately assess the options presented. This runs the risk of unintended consequences, including counter-productive charging signals. Therefore any proposals to implement a charging methodology for exporting GSPs under the CUSC should be carried out in parallel with a Distribution Connection and Use of System Agreement (DCUSA) modification. It will also be important that as much as possible the charge is forecastable for each class of user on a year by year as well as on a medium-term basis.

The work presented does not attempt to value the impact of other changes at the DNO level, such as: more active management, demand side response providers, and load shifting. In particular it is vital that any arrangements do not create an unnecessary barrier to the development of DNO's taking on the role of DSO's (this is in line with recent statements from Ofgem)

We see a significant risk that a charging arrangement that does not integrate these longer-term aims of a more flexible and responsive system into account could inhibit market participants' ability to react to short-term signals to prevent the need for additional infrastructure investment, raising the overall costs for consumers.

Whatever approach is taken, the key is that the approach looks to embrace and support market signals for flexible solutions that reduce, prevent and avoid the infrastructure impact of potentially exporting GSPs.

Therefore we would strongly discourage allowing DNOs to socialise the cost of exporting GSPs equally to all of their demand users or generators. Similarly, DNOs should not be able to take an approach which penalises new generation capacity with the full cost of the exporting GSP.

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?

Yes. These costs are born to distributed generators through their suppliers, who are responsible for matching supply and demand and ensuring

Furthermore, distributed generators which provide services to the System Operator cost-effectively compared to alternative solutions are mitigating overall network costs for consumers.

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?

Yes. We are working with the National Grid Power Responsive campaign to consider how commercial arrangements can be expanded and improved. We would not support regulatory or 'command and control' arrangements for distributed generation.

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

While we currently see National Grid as successful procurement agent for balancing services from distributed generation, we see the need to take a more local approach over the longer term to ensure that the network is balanced more locally, allowing the most cost-efficient and energy efficient solutions to come forward.

Distribution networks are already investigating these opportunities through the Low Carbon Network Fund and finding methods to reduce costs to consumers through innovative 'smart' approaches to active network management. However, there is a question about how the learning from such projects can be applied nationally.

We support some of the early views from Ofgem's September 2015 report which recognised that to achieve a more flexible, responsive system it will be important to see Distribution Network Operators transition to become Distribution System Operators. Through this transition, balancing services could increasingly be procured through distribution

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

Aggregators and other suppliers are and will play an important role in providing demand side response services, including from distributed generation. However, we would not support a model

which focusses just on aggregators or any other one market player. The focus instead should be on allowing all options to come forward, including direct relationships with generators and demand users, to find the most cost-effective opportunities.

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

No. We do not agree that wider TNUoS arrangements should be reviewed to more appropriately account for distributed generation.

It is the net flows on and off the transmission system that should be the quantity on which transmission charges are levied and this is addressed through the developing of a charging mechanism for exporting GSPs. By implementing a charging arrangement for exporting GSPs, National Grid is effectively addressing the cost impact of distributed generation onto the transmission network, and therefore negating any current perceived need to remove the Embedded Benefit through gross charging.

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?

Implementing an appropriate charging mechanism for exporting GSPs will effectively move arrangements towards those required in the future by increasing cost-reflectivity for distribution network customers which impact the wider transmission network, and also providing a financial signal to reduce such impacts.

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?

If it is deemed that distributed generation should pay for access rights to the transmission network then that should also allow them to get the same benefits as transmission connected users.

For further information please contact:

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Our Ref: DT/RD GRP/DEV/229

22 October 2015

Mr Dave Corby
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BY EMAIL & POST:
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Dear Mr Corby

POTENTIAL TRANSMISSION CHARGING ARRANGEMENTS AT EXPORTING GRID SUPPLY POINTS (GSPS) CONSULTATION RESPONSE

Banks Renewables is a renewable energy developer and operator mainly focussed on the onshore wind market.

Thank you for this opportunity to provide a consultation response.

More detailed responses to your questions are below.

In reviewing the background section of the document it seems to show that the outcome of any charging for exporting GSPs will in the main increase charges for generation connected in Scotland. Using the Net energy export column as a measure only 2 GSPs are expected to be categorised as exporting in England, none in Wales and 37 in Scotland. Some of this difference in numbers must be due to the definition of 132kV as transmission in Scotland and distribution in England and Wales. We would have expected some discussion of the influence of this change in boundary definition in this document. We have also not seen the evidence of the size of the problem caused specifically by exporting GSPs, without this it is not justifiable to add additional costs to generators in an area of the country that is rich in renewables resources.

We would also expect some protection from additional charges for projects that have already connected at distribution level with no expectation of transmission charges.

In the last 12-18 months we have been quoted for significant transmission upgrade costs on distribution connected generation projects for upgrading transformers at what would be two exporting GSPs. These costs were expected as payments from us upfront to the DNO under proposed Statement of works variations. We understand that these are treated as connection assets for the DNO and then charged to us by them. This would seem to cover the major investments required for upgrades at an exporting GSP. If these costs are covered we are not convinced that other investments and subsequent costs driven by exporting GSPs are significant.

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

We believe you are correct, as per your license and feedback to review the charging methodology to ensure it best fits the needs of the country. There are though no figures shown in the report to size the problem or opportunity now or in the future. It is difficult to judge the urgency and implications of such a major change without some financial implications. That is; what is the



estimated investment done, or expected to be done on behalf of embedded generators, that will be paid for by transmission connected generators and demand? What is the portion of energy transmitted that was generated from exporting GSPs?

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

Yes, if it is required at all. An exporting GSP will behave in a similar manner to a generator exporting power but only for part of the time.

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

The charge should follow the contractual relationship to the DNO who is connecting the customers. However this makes distribution charging even more complicated and should only be considered if linked to a review of distribution charging.

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

This seems a reasonable approach.

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

The proposal of using the difference between max export and max import as a charging base seems to have some logic when assessing and costing the impacts of generation on the transmission system.

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

Please see my introductory paragraphs.

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

This could lead to exporting GSPs becoming liable for TNUoS costs for significant circuit lengths that they could not have predicted. This looks like a fundamental definition change and we do not agree with the proposed change.

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

If the logic is that this provides a locational signal it is weak. It may help from substation to substation but has little impact from an overall GB transmission system perspective. If a generation locational signal is required is there also not an argument for an equivalent locational demand signal?

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

This is linked to the MTIS definition change which we do not agree with.

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

The charge should follow the contractual relationship to the DNO. However this makes charging even more complicated.

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?

The current BSUoS arrangements are probably not appropriate under the situation you describe but this probably widens the question in terms of whether a Distribution System Operator (DSO) role is required.

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?

This probably depends on whether the services you may be able to access would be competitive with the present services procured.

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

DNOs as they move towards considering the DSO role.

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

Yes.

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

I think this may be beneficial but it would probably need to consider where we may be 10 or 20 years into the future. If a generation locational signal is required is there also not an argument for an equivalent locational demand signal? Could this include the option of allocating TEC in some way to GSPs and allowing DSOs to manage the system beneath a GSP?

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

No, although it sets out a principle it doesn't seem to relate to the costs directly.

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?

No further comments at present.

We hope this response is helpful as you review your next steps. If you would like to discuss please give me a call.

Yours sincerely



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03/11/2015

Dear Dave,

Informal Consultation on Potential Transmission Charging Arrangements at Exporting Grid Supply Points

Drax Power Limited ("Drax") is the operating subsidiary of Drax Group plc and the owner and operator of Drax Power Station in North Yorkshire. The 4,000MW station consists of six separate units which together produce around 7-8% of UK generation. Two of these units have been converted to run on biomass as part of an ambitious project to become a predominantly renewable generator. A third unit conversion is planned for 2016, completing the largest decarbonisation project in the EU.

We welcome this opportunity to provide comments on Potential Transmission Charging Arrangements at Exporting Grid Supply Points (GSPs).

We are supportive of the key principles proposed in the open letter and encourage National Grid to raise a formal modification proposal. Presently, we believe potential charging option 2 is superior as it is most consistent with the existing TNUoS charging arrangements applied to transmission connected generators. This approach should best ensure the facilitation of effective competition and more accurately resemble the current transmission charging arrangements. This will ensure the simplest implementation.

Further, we do not believe the current BSUoS arrangements are appropriate with regards to its (non) application to distributed generation and encourage National Grid to undertake further analysis in this area. Both transmission and distribution connected generators contribute to the cost of BSUoS; however, only transmission connected users are required to pay BSUoS. As such, the arrangements appear anomalous and we encourage National Grid to develop options to extend BSUoS charges to distribution connected generators.

Answers to the questions in the consultation document can be found in Appendix 1.

If there is anything you would like to discuss further, then please do not hesitate to contact me.

Yours sincerely,

Submitted by email

Joseph Underwood
Regulatory Analyst

Appendix 1 – Answers to the consultation questions

3.1 What are your thoughts on the drivers for our work?

A clear defect has been identified and we believe National Grid should raise a CUSC Modification to develop a detailed solution.

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

Yes. Distributed Generation (DG) that causes GSPs to export, thereby subsequently triggering additional investment in transmission infrastructure and/or constraint management, should be liable for TNUoS charges.

4.2 Who do you believe is the appropriate party liable for a potential TNUoS local charge

The reasons laid out to make DNOs liable for potential TNUoS charges seem logical. However, the proposal (and/or subsequent changes to other applicable codes) must ensure DNOs appropriately apply charges to their users, to reflect the causes of additional transmission investment as a result of GSP exports. The industry has previously raised doubts over the ability of DNOs to improve the management of their networks, therefore the option of making DG directly liable for TNUoS charges should not be ruled out. Both a DNO and DG charging option should be explored further to determine the most appropriate solution.

When targeting the charge, consideration should be given by the workgroup to the running patterns of DG and importantly whether these running patterns occur during a time of the GSP exporting.

4.3 What are your views on using historic metering data to determine the charging base?

Whilst we accept that there is inherent risk in using historic metering data, Drax believes that this is an appropriate way to determine the charging base.

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

Drax believes this is a reasonable approach to calculating the charging base. It will promote stability of the tariff from year to year. Stability of tariffs is becoming increasingly important for market participants.

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

We have no comments at this time.

4.6 Do you have any comments on the potential change to the MITS node definition?

We have no comments at this time.

4.7 What are your views of potential local TNUoS charging option 1?

4.8 What are your views of potential TNUoS charging option 2?

Both options have merit and should be assessed further. Our initial view is that option 2 is superior as it is most consistent with the TNUoS charging arrangements applied to transmission connected generators. This approach should best ensure the facilitation of effective competition and maintain simplicity in calculating charges.

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

Please see answer to question 4.2. We would like to ensure that DNOs apply an appropriate transmission charging regime to their users, recovering costs from those parties that contribute to the volume of export from a given GSP (i.e. do not simply socialise costs). An open and transparent mechanism is required in order for DG operators to forecast future transmission costs.

5.1 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?

We do not believe that the current BSUoS arrangements are appropriate with regards to its (non) application to DG and would encourage National Grid to undertake further analysis. Both transmission users and DG are contributing to the cost of BSUoS, however only transmission users are required to pay BSUoS. The BSUoS arrangements as such appear anomalous and we would encourage National Grid to develop options that extend BSUoS charges to DG.

5.2 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?

National Grid should work with DG and DSR (as well as all other technology providers) in order to properly manage the transmission system at lowest cost.

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

We are not best placed to answer this question.

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

No, all options should be considered.

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

National Grid is obliged by its Licence to continually review the charging arrangements. In light of the increase in DG and DSR (and expected future increases), we are supportive of a review of wider TNUoS charging arrangements in relation to incremental wider transmission investment triggered by DG and DSR actions.

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

Yes. As more DG is built it is evidently possible that more GSPs will export onto the transmission system.

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

If National Grid has further changes to propose, then we would be happy to discuss them.



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23 October 2015

Dear Andy

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

Thank you for the opportunity to respond to this informal consultation. While we address each question further in turn below this is clearly only in the context of the material presented in the informal consultation. As you will see, our general view is that now may be an appropriate time to review whether the wider arrangements for charging remain fit for purpose in light of significant changes currently taking place in the market. Additionally, any subsequent CUSC change proposal would need to be considered separately and on its individual merits.

Drivers for our work

Q3.1; It is right that National Grid continues to review its charging arrangements in line with obligations to do so and in the context of potentially significant future changes affecting the operation of and investment in the transmission system. It is helpful that National Grid is considering the exporting GSP issue further, following responses to its informal consultation on its review of embedded (distribution) generation benefit arising from transmission charges from 2013. There is a question as to whether it is right to bring forward an incremental change in this area at this time and whether industry time and resource would be better utilised considering some of the aspects raised in chapter 5 further instead.

Local TNUoS charging options

Q4.1; This would seem sensible. There is the question of whether importing GSP's should also pay for the local aspects of their connections, but it is our understanding that DNO's triggering a new importing GSP are exposed to a

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higher connection charge so this aspect of the cost to the transmission system may already be recovered appropriately.

Q4.2; In absence of any direct contractual relationship with the parties behind an exporting GSP that trigger the investment on the transmission system, National Grid would have to pass the charge to the DNO. It will then be a matter for the DNO as to whether and, if so, how this additional cost is passed to users of its network through a DCUSA change to the Distribution charging methodology. There is a risk that the intention of such a charge is diluted and not fully passed through to those parties triggering the investment on the transmission system.

Q4.3; There are a number of uncertainties with charging on the basis of historic metering data. Using historic data means that parties are only exposed to past behaviour. It does not provide a forward looking signal which, depending on how the DNO passes through the charge, users can respond to. Depending on the configuration of generation and demand behind a GSP, such as the weather, availability of the Distribution Network, embedded generation and demand utilisation in a year and the volume data used, there is the potential that the charge may be inconsistent as to whether it applies from one year to the next. If charging for exporting GSP's was introduced, National Grid should consider as part of its TNUoS charge forecasting activity to include an assessment of GSP's going forward as to whether they could become exporting in the future. Presumably this would be based on data provided by DNO's to National Grid on demand and embedded generation growth in their areas.

Q4.4; This seems a sensible approach to add stability to such a charge.

Q4.5; Under the proposed strawman it would seem appropriate to consider a new local transformer charge, for infrastructure transformers at shared GSP's, which uses the same difference based calculation as an exporting GSP. Clearly the asset value of such transformers should be removed from the residual tariff charging base to ensure that the value of the asset is not recovered twice from users through separate components of TNUoS charges.

Q4.6; Although the suggested amendment to the definition of a MITS node seems straightforward as presented to add clarity for the purpose of charging for exporting GSP's, this should be reviewed further to consider any wider implications; in particular to Enabling Works under Connect and Manage and the calculation of Attributable Works for the User Commitment liability which also point to the MITS node definition.



Q4.7, 4.8 & 4.9; We have addressed these questions together. On the face of it, as a transmission connected generator can be exposed to both the local substation and local circuit tariff, in order to be equitable both tariffs would have to be levied. It is however difficult to fully comment on the merits of either option without understanding how the cost would be recovered by DNOs from users of their networks. Both National Grid and the DNOs would need to be transparent regarding the amount of transmission revenue that is being recovered under the charges associated with exporting GSPs, to ensure that the correct costs were being recovered from users of the DNO network, if the cost was passed on by DNOs. There are also wider considerations as to what rights are conveyed to parties who would bear such a charge, for example compensation for loss of access to the transmission system. We would expect that an associated change to the Distribution Charging Methodology under the DCUSA would be required, however it may not be appropriate for a final decision to be made on a TNUoS exporting GSP change until any associated DCUSA change is also concluded.

Longer term commercial arrangements

Given the high level but broad ranging nature of the questions raised in this chapter and which are only touched on superficially at this time, we have not considered each of the questions posed separately. We are also conscious that in the context of BSUoS charges there is an active Modification Proposal, CMP250, in progress.

In broad terms given the nature of the questions raised, we believe that given the fast changing nature of the wholesale market arrangements and the increasing role that alternative technologies are likely to play in providing energy and balancing services, it would seem to be an appropriate time to undertake a broader review of charges levied for investment and operation of the transmission system, to ensure that all parties using the transmission system or competing to provide services to the System Operator can do so on a fair and equitable basis going forward. We would be happy to participate in such a review should it be undertaken.

We hope that you find our response of help and would be happy to discuss these topics with you further.

Yours sincerely

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30 October 2015

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

EDF Energy is one of the UK's largest energy companies with activities throughout the energy chain. Our interests include nuclear, coal and gas-fired electricity generation, renewables, and energy supply to end users. We have over five million electricity and gas customer accounts in the UK, including residential and business users.

Summary

We support the initiative that National Grid has taken on charging arrangements at Exporting GSPs. While we agree that this is a step forward, we do not consider that National Grid's potential changes go far enough to address the flaws in the current charging methodology in respect of embedded generation.

Transmission charges should reflect the costs and benefits that are imposed on the transmission system by different parties whether they are directly connected or embedded. We consider that a full scale review of National Grid's charging methodology would be more appropriate than undertaking potential incremental changes, which risks investor confidence, and seems less likely to lead to a coherent charging regime.

We do not agree that it is only in the case of net export at a GSP that changes in output from Embedded Generation (EG) at a given location cause changes in flows across the transmission system.

A change in the output of any EG, whether or not the GSP that it is connected to is exporting, will arguably have effects on flows across the transmission system, and hence can contribute to or defer the need for transmission system investment. Therefore, the reform ought not to be focussed on exporting GSPs; the reform should more fundamentally consider the impacts that EG has on the need for transmission investment and hence TNUoS charges.

In addition, we note that increasingly EG can provide services to National Grid, and indeed will be very important in enabling National Grid to operate the system efficiently in future. There are likely to be a range of services provided including flexibility in output. Conversely, a large volume of connected EG is intermittent and the need for National Grid to have sufficient flexible plant on the system is increasingly starting to impose material costs on National Grid in their role as system operator in balancing the system. These costs are recovered in Balancing Use of System Charges (BSUoS). We urge National Grid

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to urgently review the scope and nature of BSUoS charges to ensure that those parties providing and using the transmission system share the costs of operating it reliably.

Finally, we consider that a review of the current demand TNUoS charge-out basis should be undertaken. The long-standing "triad" basis assumes that only flows at times of winter peak demand are important in terms of transmission system investment. It has become apparent that with new patterns of flows and new types of generator connected to meet demand, it is not only generation/demand at time of winter peak demand that influence the need for transmission system investment, and this has been taken account of in the way generation TNUoS tariffs are to be calculated from 1 April 2016, thanks to Project "TransmiT". The exclusive focus on the times of winter peak demand in the application of demand-side TNUoS charging may no longer be appropriate.

Related to this, we note that "embedded benefits" have broader implications – not least to the Capacity Market. We believe it is important that embedded generation bears its fair share of transmission and balancing costs, in order to ensure a level playing field with transmission-connected generation in capacity auctions.

Our detailed responses are set out in the attachment to this letter, which may be published on National Grid's website. Should you wish to discuss any of the issues raised in our response or have any queries, please contact Mark Cox on 01452 658415, or me.

Yours sincerely,

A handwritten signature in black ink, appearing to read "Angela Hepworth".

Angela Hepworth
Corporate Policy and Regulation Director

Attachment

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

EDF Energy's response to your questions

Drivers for our work

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

One driver is certainly that as the transmission licensee, National Grid is obliged as a licence condition 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.

We believe that the continued strong growth in embedded generation (EG) creates a need to ensure that charging for use of balancing services, and TNUoS charging rooted in network development costs caused by generation developments, are being applied in a cost-reflective way. If these charge calculation methods aren't cost-reflective, there is a risk of creating perverse incentives to develop generation at particular voltage levels so as to avoid some of the system development and operation costs.

We appreciate the thinking that lay behind some responses to your 2014 consultation, where EG is believed to have no effect on the transmission network until the moment when the GSP that it is connected to, becomes a net exporter; and you have refined this to focus only on GSPs where maximum net export exceeds maximum net import. But we do not agree that it is only in these circumstances that changes in EG generation at a given location, causes changes in flows across the transmission system. Even EG connected to GSPs that never export, still uses the transmission system. It is a matter of physics that a change in the output of any EG, whether or not the GSP that it is connected to is exporting, will have effects on flows across the transmission system, and hence can contribute to the need for transmission system investment. All EG benefits from the SQSS standards to which Grid is planned, operated and constructed (N-2 etc) – standards which are paid for via TNUoS, as far as grid capital assets are concerned. Therefore, the reform ought not to be focussed on exporting GSPs.

For instance the need that has driven the case for multi billion pound transmission reinforcements such as Western HVDC bootstrap or the Caithness Moray projects have in part been driven by embedded generation that is connecting in Scotland. It is important that the impacts that EG have on transmission costs are identified and charged.

Moreover, all EG sites, and the demand from which EG is allowed to net off for BSUoS charging purposes at present, benefits from stable voltage, frequency and phase on an energised network; we do not believe that EG should be exempt from BSUoS as it patently benefits from and needs all of the above, delivered via balancing services – of which BSUoS reflects the costs. Likewise, all demand benefits from these system qualities, maintained and delivered via balancing services; therefore, BSUoS charging to demand risks not being sufficiently cost reflective. On the other hand, changes could be made to balancing services procurement to assist EG in accessing and making more of this market and getting its fair share of the income available to balancing services providers; and we expand on this in our answer to question to 5.2.

We would like to mention also that it appears likely to be the case that the present treatment of EG in the area of TNUoS and BSUoS charges can distort outcomes in the Capacity Market. The fact that embedded generation currently does not pay transmission and balancing costs puts it at an unfair advantage competing with transmission-connected generation in capacity auctions, and could lead to inefficient outcomes.

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?

No, we do not agree with this proposition. The perception that EG only has an impact on transmission investment where the EG is connected under a net exporting GSP, is in error. The underlying physics does not respect voltage levels. Indeed there is significant transmission investment being undertaken to increase capacity from Scotland and the North of England to the South East of the country. Upgrades such as the Western HVDC bootstrap and the Caithness Moray project demonstrate the scale of this investment. While this transmission reinforcement is no doubt driven by transmission connected renewable projects, at least in part it is driven by significant renewables that have been connected at distribution voltages.

There is a potential for uncertainty created by this focus on the rather arbitrary matter of when a GSP has more maximum export than maximum net import. In a windy year – and there is significant variance in this matter from one year to another - more GSP's will be net exporting compared to a less windy year. Owners of assets will see them suddenly "caught" by the new charges in years of such variances, or may be caught if other windfarms are built under the same GSP, which is difficult to predict.

We do not understand why the proposals then limit the charge to, within (in error) that subset of GSPs, only those that have a local circuit under the new definition, further limiting it in relation to the balance of net export over net import, so that for example, a GSP with a peak import of 75MW and a peak export of 80MW would be charged based on 5MW. It would seem more logical to be charging TNUoS based on a TEC holding based on the peak net export.

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

We did not feel that the “Supplier agency model” that NGET contemplated in the 2014 consultation, based on charging Suppliers, was practical (for the reasons that you identified); we understand that NGET lacks a direct relationship with these EG, and therefore agree that a charge via DNOs, notwithstanding the reliance on DUoS charging developments to allow it to be properly targeted and so to comprise an appropriate signal, is the right approach.

For the purpose of EC838/2010, it needs to be considered whether a charge levied via DNOs, ultimately as extra GDUoS on EG, falls within the cap on annual average generation transmission charges (excluding connection, losses and BSUoS); this aspect is not mentioned in the current consultation.

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

We have no strongly-felt view, but perhaps a preference for the forecast data that is provided by DNOs to National Grid under current Grid Code requirements (week 24 data), given that the amount of EG has been increasing quite fast in some areas. New forecasts are already being given by DNOs on >5 MW embedded generators that are connected or due to connect, at week 24. The GCRP is due to review the quality of this data; we would like to see the outcome on that review. If the data used is historic, it should be only data for the last year. A wider point is that it would be helpful for DNOs (or some other body) to publish much more information around EG; we’d like to see more data and more quickly.

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

We do see the logic set out in the paper that the proposed volume netting approach means 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. Such a GSP has a lot of EG, and yet would only see a very small charge even once it fitted your quite conservative criteria (of max export > max import). Therefore, we do not like the proposed netting approach, particularly since it is being applied to new charge proposals that are much removed from the cost-reflectivity in the calculation of normal network-expansion-cost-driven TNUoS charges.

Q4.5. Do you have any comments on our proposed approach to transformers at shared exporting 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, whereas if the GSP only had one customer (the DNO) directly connected to it, there would have been a substation charge. The consultation document proposes that these transformer costs be charged for via a new local transformer tariff; this seems reasonable. There are a number of shared GSPs but only one so far, we understand, is an exporting

GSP in your definition, so this is a very immaterial change overall (only, for that one GSP, resulting a new tariff of c. £3/kW)

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

It's a small and subtle change that is necessary in this context, if the proposed new local circuit charge for net exporting GSPs is implemented - which we do not believe is the right way forward, but is at least a step towards addressing the implicit cross-subsidy in current TNUoS-related "embedded benefits". There is a MITS map at the moment so that we know what are the MITS substations. However, we do not want MITS to be unstable as a geographic reality, and we need to maintain transparency as to what parts of the transmission network comprise MITS.

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

Transmission-connected generators all pay small cost-reflective local substation charges. It makes sense that EG at net exporting GSPs should do so too. This is a very modest proposal in terms of materiality.

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

We do not believe that the proposed new local circuit charge for net exporting GSPs is the right way forward, but it at least represents a step towards addressing the implicit cross-subsidy in current TNUoS-related "embedded benefits".

We do not agree with the proposed limitation of the charge to, within the subset of net exporting GSPs, only those that have a local circuit under the new definition, nor do we agree with further limiting it in relation to the balance of net export over net import, so that for example, a GSP with a peak import of 75MW and a peak export of 80MW would be charged based on 5MW. It would seem more logical to be charging TNUoS based on a TEC holding based on the peak net export. We do consider, though, that all EG affects transmission investment and so should be subject to TNUoS charges.

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

It is important that the revised DUoS charges should be as cost-reflective as possible, and not "smeared".

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?

No, we do not consider they are appropriate. Deployment of embedded generation is increasing the constraint resolution costs that are a growing proportion of BSUoS – about half of the growth in Scottish generation is from embedded wind power there. Looking to 2020, forecasts of additional system operational costs relating only to the management of

the lack of inertia (and the impacts on frequency reserves) of the new solar (all embedded) and wind (half embedded) plant, have been in the range £50m to £1b p.a. Across the 2015 summer months, National Grid flagged up to the operational forum that an extra £4m a month of BSUoS costs arose due to managing reduction in inertia specifically associated with new (all embedded) solar plant. We therefore very much agree with the words used in this question, that parties who do not pay BSUoS are driving costs to the System Operator in managing the system

All EG sites, and the demand from which EG is allowed to net off for BSUoS charging purposes at present, benefits from stable voltage, frequency and phase on an energised network; we do not believe that EG should be exempt from BSUoS as it patently benefits from and needs all of the above, delivered via balancing services – of which BSUoS reflects the costs. Likewise, all demand benefits from these system qualities, maintained and delivered via balancing services; therefore BSUoS charging to demand should be on a gross, not net (of EG), basis.

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?

Yes, changes could be made to balancing services procurement to assist EG in accessing and making more of this market and getting its fair share of the income available to balancing services providers. Currently National Grid has over 20 market arrangements that it can utilise to manage the system. This suite of system services is supported by bilateral contacts that National Grid procures from time to time. These services enable National Grid to manage day to day operations as well as emergency situations. Critically it enables National Grid to manage voltage and frequency as well as energy balance. Voltage management is largely a local effect and is particularly suited to being managed locally so there is a clear opportunity to utilise DG and DSR to support this. Frequency can be managed at a DG level and DSR level primarily with multiple asset aggregation. Energy management is already demonstrated at the DG and DSR level with capacity following shortly as recognised by DSR and the Governments Capacity Market transitional arrangements.

National Grid should therefore establish how best to bring forward innovative players at the DG & DSR level including aggregators. Alongside new players, new technologies such as system storage (e.g. batteries) should be considered. The growing issues associated with system inertia could benefit from very fast frequency response services that these new technologies can provide.

Therefore, two key areas should be addressed within this thinking.

- National Grid operates at a scale with many of its contracts that smaller players cannot access. Minimum levels of capacity can create thresholds that aggregators struggle to meet. It is important to recognise that many small assets could deliver as well as one large assets and potentially with increased flexibility.
- Similarly, the short term nature of many contracts and the volatility of price changes year to year mean that it is challenging for these new approaches to come forward

without some longer term revenue certainty. Equally, greater visibility of potential market opportunities over multiple years will be helpful to market participants. Some form of extended contract (multiple years) may be required to incentivise these players and technologies particularly if future market visibility is limited. However, this should not compromise the ability of National Grid to procure services as cost-effectively as possible and long term contracts should only be considered where it can be demonstrated that this is the most cost effective approach for consumers.

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

This area is relatively new. We believe that there are at least three parties that we can identify that could provide some form of service.

- DNO's are limited by their operating conditions in providing some of the services (e.g. generation) such that their approach is likely to be inflexible. Similarly questions on conflicting interests could be raised about any activity that increases their regulated asset base.
- Small aggregators exist but are still infant in this space. Many differing innovative business models are appearing from frequency aggregators, building optimisers to virtual power plants and virtual portfolio optimisation.
- With an increasing proportion of an energy suppliers customer base on half hourly meters and a growing number of energy suppliers customers carrying out their own optimisation of their asset mix there could also be a role for energy suppliers to support the provision of these services.

Therefore, it is our view that National Grid should not take any actions that are detrimental to innovation in this landscape and that enable a range of new and innovative business models and technologies to come forward. As these emerge it will naturally become clearer which ones are winners from the consumer's perspective.

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

No. As noted in Q5.3 there are a range of options available and in order to maximise innovation no limitations should be placed on the market place.

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

Yes, as regards distributed generation, as changes in its output do alter flows across the transmission system and will trigger or defer transmission investment – it should be charged cost-reflective TNUoS charges that reflect these effects on transmission system investment. The approach to demand TNUoS charging is worthy of review : we see the topic of embedded generation, in the current commercial context of net demand TNUoS charging, as being linked to how demand TNUoS tariffs are formulated. The current demand TNUoS formulation, for half-hourly metered demand, levies charges only according to each site's demand at the three "triad" half hours of maximum national

demand (considered only during November to February). This assumes that only flows at times of winter peak demand are important in terms of transmission system investment. It has become apparent that with new patterns of flows and new types of generator connected to meet demand, it is not only generation/demand at time of winter peak demand that influence the need for transmission system investment, and this has been taken account of in the way generation TNUoS tariffs are to be calculated from 1 April 2016, thanks to Project "TransmiT". The increasing value of TNUoS tariffs is being driven by investment in part to accommodate renewable generation and is influenced by both the capacity and location of this capacity. That is to say, it appears that total costs faced by transmission owners, and their growth, are significantly influenced by factors other than peak demand. We would like to suggest that the triad charging basis for demand TNUoS charges for half-hourly metered demand, entirely unchanged in 25 years, be reviewed to see if the pure focus on the times of winter peak demand remains properly reflective of the costs of transmission system investment as they relate to and are influenced by the temporal disposition of 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?

Yes; we do not believe the proposals are the right way forward, but they do at least represent a small step towards addressing the implicit cross-subsidy in current TNUoS-related "embedded benefits".

There is evidence, for example from the wording of this question as well as the previous reviews in this area, that National Grid has a plan as to what longer-term, more fundamental reforms to improve cost-reflectivity that it will seek to introduce to charging-related "embedded benefits". We do approve of this, if it is indeed so - but for investor certainty, consider that it would be better to be more open about the long-term direction of travel, so that investors can take this into account.

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?

Our answers to questions 5.2 and 5.3 were quite comprehensive on this point

EDF Energy
October 2015

dave.corby@nationalgrid.com

By Email Only

27 October 2015

Dear Dave,

National Grid Informal Consultation Paper: Potential Transmission Charging Arrangements at Exporting Grid Supply Points (GSPs)

Electricity North West Limited welcomes the opportunity to provide comments on the above informal consultation paper from National Grid.

In summary, we agree with the principle of charging GSPs for net exports where they cause costs to arise on the transmission network but there are a number of areas that must be considered before developing any potential charging methodology. In this context we note that the charging base would need to include offshore generators that feed into a DNO network at an (OFTO) GSP which in turn causes export at another (onshore) GSP. We have some concern that individual GSPs should not be considered in isolation where they are electrically interconnected with other GSPs through a distribution network. We give the example above of an OFTO GSP having sufficient generation to cause export at an adjacent onshore GSP; more generally, where GSPs are interconnected on the distribution system there is always the possibility that export at one GSP is the result of transmission flows, i.e. the distribution system operating in parallel with the transmission system. We believe that exporting GSPs should be treated in a similar manner to exporting generators in the charging methodology and this could be achieved by granting the exporting GSPs a TEC and utilising this value in the charging model.

In our opinion, any market arrangements to support such charges should be based on a DNO agency model (see Q4.2), which would need to allow any such transmission charges to be passed through to the generators deemed to be causing the export. This would require modifications to the existing DNO licences and changes to the existing charging methodology to ensure that these charges were recoverable from customers.

The informal consultation paper asks for responses to several specific questions and our response to each question is set out in the attached annex.

If you have any queries about anything in our response, please do not hesitate to contact me.

Yours sincerely,

A handwritten signature in cursive script that reads "John Leonard".

John Leonard
Corporate Finance Planning Manager

DDI: 0843 311 4122
Email: john.leonard@enwl.co.uk

National Grid Informal Consultation Paper: Potential Transmission Charging Arrangements at Exporting Grid Supply Points (GSPs)

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

We believe that a detailed assessment of the factors driving costs on the transmission network should be conducted and used as the basis for building a detailed charging methodology proposal.

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

This would seem logical but would be dependent on the outcome of the costs analysis referred to in Q3.1 above. If exporting GSPs are found to be driving increased costs on the network then it would be appropriate to limit such charges to those GSPs. Under National Grid's current charging methodology only winter peak demand is considered to drive costs and hence only GSPs which export at this time should be liable for the proposed charges. Extending charges for GSPs that export at other times would need to be justified through a comprehensive review of the transmission charging arrangements. If it is deemed appropriate to introduce charges for exporting GSPs then they should be treated in a similar manner to exporting generators in the charging methodology. This could be achieved by granting the exporting GSPs a TEC and utilising this value in the charging model.

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

In our opinion, it would be most appropriate for any TNUoS local charge to be levied on the local DNO who would then recover these costs from the relevant customers giving rise to the charges. This structure would require changes to both the DNO licences and to the current charging methodology to allow the implementation of a DNO agency approach.

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

This would seem appropriate assuming that the charging base is correct.

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

Current charging base issues would need to be addressed prior to commencing this approach i.e. the charge base needs to reflect what is being modelled in the cost model (ICRP) otherwise it is not appropriate.

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

We disagree with the proposed approach to transformers and believe that it should be treated as a separate issue. In our opinion, all transformers should be treated on a consistent basis.

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

There should be a consistent approach regardless of which user type is connected, including standard boundaries.

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

Any new charges introduced for distributed generation would require modifications to the price controls of DNOs, including revised definitions, as well as changes to the current charging arrangements. We believe that NGET need to demonstrate how this option is reflective of their underlying cost model before any decision can be made on the appropriateness of the charging option.

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

Same as for Q4.7 above.

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

We believe this should be determined by DNO's however any changes would need to be implemented in parallel with any such charges from National Grid. Modifications to DNO licences etc. would need to be finalised in advance of any implementation date to ensure any costs received can be passed-through to customers.

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?

The agency approach should apply in all cases whereby charges are levied on DNOs who have the authority to pass such charges on to their customers.

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?

Before considering alternative arrangements, NGET should produce a detailed model of the drivers of increased costs on the network (currently NGET model is based on the winter peak and the summer minimum).

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

DNOs are best placed, and most appropriate, to provide this service. It would not be appropriate for National Grid to contract directly with parties connected to distribution networks as this could potentially drive costs on the distribution system and result in higher overall costs to consumers.

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

Nothing to add in addition to the modelling point already raised.

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

This is an essential pre-requisite to address the issues raised in this consultation. The current approach to transmission charging is inadequate to address these issues in a cost reflective manner.

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?

In our opinion, a wider review needs to be conducted first. The costs need to be modelled appropriately first before levying any charges.

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?

National Grid should be looking at a whole system approach and looking to assess the services that distribution systems can provide to reduce costs overall. This may include distribution systems undertaking work to resolve problems on the transmission system through commercial arrangements.

Response to National Grid consultation by

Eneco UK

Charging arrangements for Exporting GSPs

Monday 9th November 2015

Introduction

Eneco UK has built five onshore windfarms with an installed capacity of 200MW in Scotland over the last seven years, at an investment cost of around £300m. One project (69MW) is transmission-connected and four projects (133MW) are distribution-connected. All of these projects are located in Northern Scotland, or the region with the most Exporting Grid Supply Points (GSPs). Eneco UK would therefore clearly be an affected party by any suggested charging changes for a distribution-connected export plant in Northern Scotland.

Response summary

Eneco UK recognises that charging structures and regulations will change over time and that the network is currently in a state of change. Our headline concerns, to this informal consultation, are as follows. The proposal for charging signals for local Transmission Network Use Of System (TNUOS) charging:

- Suggests some ideas that could be considered a first step in a broader review of transmission and distribution charging that is required as a result of, in part at least, the rise in distributed generation being added to the network and which is set to continue.
- Needs to take into account the changing nature of the interaction of distribution and transmission networks; the fact that distribution networks as well as transmission networks, are both moving into a world of more active supply and demand.
- Should address the need for forward planning of grid reinforcements, not just from the traditional demand-led reinforcement but also supply-led.
- Must deliver consistent investment drivers between transmission and distribution, since generation connections can be paid for "by beneficial support" to the distribution network under Common Distribution Charging Methodology (CDCM) and Electricity Distribution Charging Methodology (EDCM).
- Should not progress a Connection and Use of System Code (CUSC) Mod process until the broader rules of engagement in this new world has been set out.
- Must acknowledge that parties that have invested a considerable amount of money in distributed generation in recent years do not expect a negative impact on existing projects brought about by a retrospective change in charging methodologies. TNUOS charges are

based on a forward-looking methodology and this principle should be adopted for existing projects.

We make more specific points in answer to the questions in the consultation below.

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

In short, our view is that this is one aspect that needs to be picked up as part of a broader review of the transmission/distribution interface, as described in the summary of our position.

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

No, for the reasons set out above. There needs to be a much broader dialogue concerning the interface between transmission and distribution and the cost recovery of relevant assets.

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

We believe that a local TNUoS charge would need to be considered and assessed in the broader context if an Exporting GSP is considered to have a wider impact on the transmission network. To that extent, this analysis presented is incomplete.

In answer to this question specifically, the Distribution Network Operator (DNO) is potentially most able to effectively respond to a new local signal, but joined-up thinking is required through consultation with current and future stakeholders, as set out in our headline comments.

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

Following a further and broader consultation, we agree that use of historic metering data would be a reasonable basis upon which to determine (eventual) costs and benefits.

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

As we enter a world of greater charging complexity, this proposal seems overly simplified and does not reflect the constantly changing demand and generation at the GSP. Simplicity is a good thing, but an exporting GSP is not the same as a generator. For example, it is not possible to allocate export levels to a single generator if several are active. Also, exports may vary significantly if demand patterns are changing; export may fundamentally be caused by a decrease in demand rather than an increase in generation. Furthermore, the GSP will flip between net import and net export and so a more time-reflective charging structure would seem to be appropriate here. The approach is not yet fully considered in our view and needs further consideration.

The distinction between sole user connections and multiple (generation) user connections also needs to be made clearer.

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

We consider such a change is not justified by this proposal given the point above, that this proposal constitutes a fraction of the changes required.

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

Distributed generation, even where a GSP Group is exporting, creates a benefit from deferring reinforcement/investment. This option seems to suggest an annual capacity charge in a situation where a GSP may be exporting in a single settlement period when a GSP is exporting, thus suggesting a more flexible charge would be appropriate.

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

As above, this section assumes that exporting GSPs are the same as generators and so we consider this solution is incomplete for the reasons set out above.

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

As mentioned above, the essential points are to consider the growing interface between supply and demand and the need for a charging framework that is cost reflective and optimises the world of flexible supply and demand. Crucially, the charging framework should be on an assessment of supply and demand needs in advance and with no retrospective application to existing projects.

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?

System costs should be allocated to those that use them.

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?

Absolutely, all appropriate options should be considered as part of a broader review where the role of a more active distribution company is central to the analysis, as well as the interface with the transmission company.

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

Power suppliers, off-takers or aggregators.

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

No. That is one solution but a full examination of a wider set of questions is required.

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

Yes, in the sense that the wider impacts and benefits are taken into account. And only if on a forward-looking basis.

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?

No.

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?

Yes. The DNOs are the key since they manage, control, monitor and operate a modern active distribution network. The DNOs require a more flexible and dynamic interface with National Grid Electricity Transmission (NGET). Ofgem should play a strong role in facilitating this.

Ends 09/11/2015.

Energy UK response to National Grid's Potential Transmission Charging Arrangements at Exporting Grid Supply Points (GSPs)

18 May 2015

About Energy UK

Energy UK is the trade association for the GB energy industry with a membership of over 80 suppliers, generators, and stakeholders with a business interest in the production and supply of electricity and gas for domestic and business consumers. Our membership encompasses the truly diverse nature of the UK's energy industry – from established FTSE 100 companies' right through to new, growing suppliers and generators, which now makes up over half of our membership.

Our members turn renewable energy sources as well as nuclear, gas and coal into electricity for over 26 million homes and every business in Britain. Over 619,000 people in every corner of the country rely on the sector for their jobs with many of our members providing lifelong employment as well as quality apprenticeships and training for those starting their careers. The energy industry adds £83bn to the British economy, equivalent to 5% of GDP, and pays over £6bn in tax annually to HMT.

Executive Summary

Energy UK welcomes the opportunity to respond to National Grid's consultation on potential charging arrangements at exporting Grid Supply Points (GSPs). We are broadly supportive of a method being developed to charge exporting GSPs according to the net flows onto and off the transmission system. It is our view that a successful implementation of charging arrangements on exporting GSPs will depend greatly on a number of factors which are not yet addressed in any great detail. These include:

- **Method** – Any method that is developed to charge exporting GSPs needs to apply to all importing and exporting GSPs on a consistent basis (with charges only being applied to exporting GSPs). This should ensure that the charges are transparent and cost reflective as well as facilitating the move towards smart grids and Distribution System Operators (DSO).
- **Price signals** – The proposals do not provide sufficient information about how the charge would be implemented and how exporting GSPs impact transmission network/system costs. Any charge applied to exporting GSPs needs to produce the appropriate signals to manage embedded generation before physical reinforcement of the network is needed.
- **Application** - Without knowledge of how DNO's would pass charges on to connected parties it is difficult to accurately assess the options presented. This runs the risk of unintended consequences, including counter-productive charging signals. Therefore any proposals to implement a charging methodology for exporting GSPs under the Connection Use of System

Code (CUSC) should be carried out in parallel with a Distribution Connection and Use of System Agreement (DCUSA) modification.

- **Direction and certainty** - Charges for all generators, including Distributed Generation (DG) should be forecastable for each class of user on a year by year basis, as well as on a medium-term basis. Investment decisions are being made based on the current regime therefore more should be done to ensure that all market players understand how the charging regime will evolve in the future.

Energy UK welcomes the opportunity to further discuss this consultation with National Grid. Should you require further information or clarity on the issues outlined in this paper then please contact Kyle Martin on 020 7747 1834 or kyle.martin@energy-uk.org.uk.

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Response to consultation questions

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

The impact of exporting GSPs on local assets has not been explained in the consultation. The analysis shows that many GSPs are already exporting but there is no demonstration that this is demanding new investment in local assets. Such assets allow flows in both directions, import and export therefore it is unclear what the justification is for local asset charges.

If justified, we consider that the local Transmission Network Use of System (TNUoS) charging option should be applied to those GSPs which export power onto the transmission network but any method developed to address exporting GSPs should be consistent across Great Britain (GB). Although this is currently more of an issue for GSPs based in Scotland and Northern England any charging method should be consistent across all GSPs.

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

We consider that the Distribution Network Operator (DNO) is best placed to be the party liable for potential TNUoS local charges. This is because the DNO has a contractual relationship with all Distributed Generators (DG) and large demand users on its network as well as National Grid. Also, as DNOs are regulated businesses they are not subject to market conditions and therefore less likely to become insolvent (compared to other entities such as energy suppliers). There may be some need for changes to the DNOs licence to be implemented to allow for the collection of TNUoS charges from DG.

In addition, we consider that making the DNO responsible for the recovery of TNUoS local charges could help facilitate the move towards a Distribution System Operator (DSO) model in GB if the right incentives are put in place. If DNOs can manage the recovery of TNUoS local charges then not only would this help with flows onto and off the transmission system but it could also open up significant advances as to how the distribution network is managed in the future with smart networks. Whichever approach is taken, the key is that the approach looks to embrace and support market signals for flexible solutions that reduce, prevent and avoid the infrastructure impact of potentially exporting GSPs (this is in line with recent statements from Ofgem¹).

We would further note that National Grid's analysis does not specify how long the periods are during the year that export is greater than import. The length of the period is very important as it changes whether the appropriate signal should be directed at capacity or at market flexibility. For example, if max export is greater than max import for very short periods, the appropriate cost-effective response may be focussing on market signals that reduce output within that GSP during specific periods.

There is a potential for uncertainty created by the focus on when a GSP has more maximum export than maximum net import during a financial year. In a windy year there is significant variance in generation from one year to another. In a windy year more GSP's will be net exporting compared to a less windy year. Owners of assets will see them suddenly "caught" by the new charges in years of such variances or may be caught if other windfarms are built under the same GSP. Charges should be forecastable for each class of user on a year by year basis, as well as on a medium-term basis.

¹ https://www.ofgem.gov.uk/sites/default/files/docs/2015/09/flexibility_position_paper_final_0.pdf

Actions by the DNO or by other users of the distribution network can impact whether a GSP is exporting onto the transmission network or not. For example, the DNO could close circuits that isolate the generator from local demand, or a local manufacturer could close down causing a significant reduction in local demand. Both could turn a GSP from not exporting, to exporting, although the DG has not changed its behaviour. By making DNOs the charge payer DNOs would be faced with appropriate signals for managing their networks and making least cost choices between investment in distribution system reinforcement and additional charges for increased capacity at GSPs.

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

Using either historic metering data or forecasts to determine the charging base for exporting GSPs can be problematic.

Historic metering data may provide the most accurate information but issues such as outages need to be taken into account along with the rapid expansion of DG on the distribution network. The rate of DG installations varies year on year and is dependent on changeable policy drivers. Use of solely historic data would mean new generation would not be attributed any charge in the charging period immediately following its commissioning.

Forecasts can take these issues into account but there is inherently some degree of risk with any forecast. Using week 24 data along with accurately calculating load factors would be beneficial but consideration should be made as to how these charges are applied. For example, other network charges are calculated ahead of the applicable financial year with CMP244 'Set final Transmission Network Use of System (TNUoS) tariffs at least 15 months ahead of each charging year' and CMP250 'Stabilising Balancing Service Use of System (BSUoS) with at least a twelve month notice period' currently progressing through the CUSC modification process to extend the visibility of charges and reduce volatility for users.

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

The impact of exporting GSPs on local assets has not been explained in the consultation. The analysis shows that many GSPs are already exporting but there is no demonstration that this is demanding new investment in local assets. Such assets allow flows in both directions, import and export therefore it is unclear what the justification is for local asset charges.

The charging base proposed in the consultation (the difference between the GSP's maximum export and its maximum import for GSPs with a higher maximum export than their maximum import) would appear to be appropriate to measure the impact on local transmission infrastructure. However, further analysis is needed to show the impact exporting GSPs are having on local transmission assets. Any charge applied to exporting GSPs needs to produce the appropriate signals to manage embedded generation before physical reinforcement of the network is needed.

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

National Grid's proposed approach to transformers at a shared exporting GSPs will need to consider how additional DG connecting to the network are treated (the plus 1MW issue) where the full cost of a new transformer could be attributed solely to this additional capacity. Providing stability to any charge

applied to exporting GSPs is crucial not only to ensure DG is not subject to volatile charging as well as to ensure that effective market signals are incentivising the right behaviour.

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

National Grid's proposals to change the definition of a Main Integrated Transmission System (MITS) node needs to consider the future implications of such a change and should not just be considered in a "silo" as part of the review of exporting GSPs consultation. There could also be an issue for MITS nodes which flip between importing and exporting depending on the level of generation/demand on the distribution network.

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

Any charging method applied to DG at exporting GSPs needs to be transparent and reflective of the additional costs the exporting GSP placed on the network. Transparency of the method and predictability also need to be taken into account to ensure volatility is addressed.

Demand will also play a role as to whether a GSP is importing or exporting and therefore signals should be consistent to allow the most efficient and lowest cost options for power transmission to prevail.

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

We note that the consultation document shows some large differences in TNUoS local circuit charges which could have some significant impacts on DG already connected to an exporting GSP and those that will be connecting in the future. The interactions with interruptions on the transmission system also need to be considered in terms of compensation for DG exporting on to the transmission system.

Demand will also play a role as to whether a GSP is importing or exporting and therefore signals should be consistent to allow the most efficient and lowest cost options for power transmission to prevail.

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

Any charging method put in place to recover TNUoS local charges needs to be transparent and allow users to forecast their costs. DNOs will need to consider how these charges are recovered from users, we consider that only a pass-through charge would be justified and understand that the question would require further consideration through the DCUSA change modification process. DNO charging methodology cannot be an afterthought and must be developed in tandem with any changes to transmission charging methodology.

We consider that the signal for charging exporting GSPs are important and should ensure that this drives behaviour that would avoid physical upgrades to the network. As such, how these charges are passed through would also be important for example if GSPs are found to export at night then a charge on Solar PV generators may not be appropriate and would not provide a signal to change behaviour. The proposal as set out in this consultation does not provide sufficient information about how the change would be implemented and how exporting GSPs impact transmission network costs.

Without knowledge of how DNO's would pass charges on to connected parties it is difficult to accurately assess the options presented. This runs the risk of unintended consequences, including

counter-productive charging signals. Therefore any proposals to implement a charging methodology for exporting GSPs under the CUSC should be carried out in parallel with a Distribution Connection and Use of System Agreement (DCUSA) modification. It will also be important that as much as possible the charge is forecastable for each class of user on a year by year as well as on a medium-term basis.

10. 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?

We consider that BSUoS charging arrangements should continue to be applied on a net basis and should not be done on a gross basis because costs are dependent on net (not gross) flows. Charging based on net flows will also incentivise DNOs to transition to DSOs where the appropriate signals would incentivise them to balance their distribution network.

Where National Grid are procuring services directly from DG for balancing purposes, it may be appropriate to charge them BSUoS. However, if BSUoS was to be applied to these parties then changes should also be considered regarding how balancing services procurement to assist DG in accessing and making more of this market and getting its fair share of the income available to balancing service providers.

11. 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?

We consider that National Grid should seek to work with DNOs to ensure that assets that are able to be used for managing both the transmission and distribution system should be able to do so without the need to enter into overly restrictive contractual agreements which limit the assets use.

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

We consider that a DSO or a third party aggregator contracting with National Grid would be an efficient party to assist in the procurement of balancing services from DG. Any move towards contracting directly with small scale generators needs further consideration.

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

We consider that all options should remain open where best value to the end consumer is achieved.

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

We consider that wider TNUoS arrangements should not be reviewed at this time to take account of DG and responsive demand. The EU network codes are due to be implemented in the next couple of years which will provide a platform for a review of wider TNUoS arrangements to take place. We consider that any wider fundamental changes to TNUoS arrangements (or indeed to any part of the TNUoS or BSUoS charging arrangements) should only be considered once the EU network codes are in place.

The long-standing “triad” basis, unchanged for over 25 years, assumes that only flows at times of winter peak demand are important in terms of transmission system investment. It has become apparent that with new patterns of flows and new types of generator connected to meet demand, it is not only generation/demand at time of winter peak demand that influence the need for transmission system investment, and this has been taken account of in the way generation TNUoS tariffs are to be calculated from 1st April 2016 due to Project “TransmiT”. The exclusive focus on the times of winter peak demand in the application of demand-side TNUoS charging, may no longer be appropriate and may need reviewing.

We also note that it appears likely to be the case that the present treatment of DG in the area of TNUoS and BSUoS charges can lead to perverse outcomes in the Capacity Market. Existing assets (sunk costs) are failing to get contracts while new build DG are allocated Capacity Market contracts (requiring new investment capital). This is partly due to the value of “triad” avoidance services to DG which may be economically inefficient. DG are thus winning Capacity Market contracts due to their impact on transmission investment requirements, at the expense of generators that have already been accommodated on the transmission system; it is essential that there is a level playing field for distribution and transmission connected generation competing in the Capacity Market.

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

We are uncertain as to whether the options laid out in section 4 help move arrangements towards those required in the future. The effectiveness of distribution signals will be key as will the ability of distribution networks to manage their impact on the transmission network. These signals need to work with each other to create a cost efficient network model across GB.

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

If it is deemed that DG should pay for access rights to the transmission network then that should also allow them to get the same benefits as transmission connected users. However, once there is a system for charging for exporting GSPs there will need to be review of the treatment of Bilateral Embedded Generation Agreement (BEGA²) / Bilateral Embedded Licence Exemptible Large Power Station Agreement (BELLA³) contracts to ensure these generators are treated fairly.

The issue regarding what is classified as transmission assets in England and Wales which are categorised as (275kV and 400kV) in comparison to Scotland where transmission is classified as (132kV) is also creating a distortion. The definition of an exporting GSP in Scotland is therefore different and warrants further consideration as to how these systems are treated to ensure price signals are effective as far as possible and consistent throughout the GB.

² A BEGA provides Transmission Entry Capacity (TEC) allowing the generator to have the right to operate in the electricity balancing market and export onto the National Electricity Transmission System.

³ A BELLA does not commit the generator to adhere to the Balancing and Settlement Code (BSC) as a BELLA does not give the customer rights to operate in the electricity balancing market and export onto the National Electricity Transmission System.

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

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:

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Respondent Specific Information

Respondent Name	Simon Lord
Company	ENGIE
Contact Telephone Number	01352-705289
Please confirm if you wish this response to be treated as confidential	This response is not confidential.

Informal Consultation exporting GSP	
Question	View
Q3.1 What are your thoughts on the drivers for our work?	<p>The growth of distribution connected plant is clearly a major structural change which can only become of increasing importance in the coming years. Charging arrangements must reflect the economic costs and benefits of connecting plant at both the distribution and transmission levels. Given this we support the review.</p> <p>As a basic principle we consider that, at the same location, exporting GSPs and transmission connected generation share the same characteristics and in general should be charged as such.</p> <p>The review should concentrate on ensuring that the cost of running the transmission system is not simple borne by transmission connected customer but is shared by embedded customers in an appropriate way.</p>
Q4.1 Do you agree that any local TNUoS charging option should be limited to those GSPs which export power onto the transmission network?	<p>This principle risks being too restrictive. The principle will drive a shallow approach. A deeper approach should not be ruled out at this stage of the analysis.</p> <p>In the long term it may be appropriate to base charges at GSPs on the incremental flows on the transmission system created by embedded generation.</p>
Q4.2 Who do you believe is the appropriate party liable for a potential TNUoS local charge?	<p>The current contracting arrangements would require the DNO to collect any fees or charges. In the medium term (over 5 years) it may be prudent to work towards an embedded register so charges can be directed at specific users again via a supplemental DuOS charge.</p>
Q4.3 What are your views on using historic metering data to determine the charging base?	<p>See answer to Q 4.1. It is important to address the more fundamental issue.</p>
Q4.4 Do you have any comments on this approach to the potential calculation of a charging base for these options?	<p>See answer to Q 4.2. The charges would be DuoS charges collected and managed by the distribution company</p>
Q4.5 Do you have any comments on our proposed approach to transformers at shared exporting GSPs?	<p>In the long term it is not clear that this approach is suitable; it is preferable to find an enduring solution. This could involve charges being based on incremental flows with a share of TNUoS applied to GSPs where this results in “generation type flows “.</p>

Q4.6 Do you have any comments on the potential change to the MITS node definition?	The definition should be consistent with whatever is determined to be the enduring solution.
Q4.7 What are your views of potential local TNUoS charging option 1?	See answer to Q 4.1. Whilst option 1 is coherent, it is important that a thorough analysis addresses the more fundamental issue.
Q4.8 What are your views of potential TNUoS charging option 2?	See answer to Q 4.1 simply targeting existing or future GSPs fails to address the more fundamental issue
Q4.9 Do you have any comments on potential options for a recovery mechanism for any local TNUoS charge passed through to a DNO?	See answer to Q 4.2. Ultimately, we expect this to be passed on by the DNO to generation connected at each GSP via a change to the methodology. This distribution company is best place to apportion this charge.
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?	<p>We believe that this is an issue of equal if not greater magnitude to the TNUoS issue and ultimately embedded generation should share both the benefits and the costs associated with balancing and system support actions.</p> <p>As a minimum embedded generation that receives benefit or causes costs on the transmission system should be subject to some form BSUoS although it is recognised that not all of the benefits of being transmission connected (e.g. constraint payments) flow through to embedded generation.</p> <p>Much of the increase in BSuOS is driven by embedded generation connected on the system. The issue should be treated as a priority as it impacts the long term economics of both transmission and distribution connected generation.</p>
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?	We support this and believe that a project of similar duration to Project Transmit is required to address this issue possible by a significant code review. See above.
Q5.3 Who do you believe could be an efficient party to assist in the procurement of balancing services from distributed generation?	The SO is the correct party to optimise the procurement of balancing services from embedded generation.

<p>Q5.4 Do you believe our thoughts should be limited to models considering an aggregator at this time?</p>	<p>Direct contacts with the SO should be considered.</p>
<p>Q5.5 Do you believe wider TNUoS arrangements should be reviewed to more appropriately account for distributed generation and responsive demand?</p>	<p>We support this and believe that a project of similar duration to Project Transmit is required to address this issue. See above.</p>
<p>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?</p>	<p>No, the proposed changes would simply delay a more holistic look at the issue.</p>
<p>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?</p>	<p>As noted in the various section above.</p>

Exporting GSPs

Need to recognise that the growth in distributed generation is changing the nature of distribution networks and power flows both within them and between the T & D systems and (to varying degrees) on the transmission system.

The Issue is not exporting GSPs per se but more to do with the changing nature of interaction between the Distribution and Transmission networks. As such, it is necessary to ensure that strategic and wider policy issues are considered such that any changes to the charging arrangements for GSPs are consistent with overall government energy policy objectives (e.g. promotion of renewables/local energy/distributed generation) and do not have to be revisited in the near future.

Although not covered by charging proposals, the issue of network operations and the interaction between networks is central to this matter and cannot be ignored (we cover this later)

Accept that where GSP behaviour changes and drives additional investment by NGET, then the costs of this need to be recovered. In a simple situation, where load growth requires that a GSP be reinforced for demand, then the relevant parties should have the costs allocated to them. The reverse should also be true (particularly where generation is increasing in a DNO network) in that NGET should be able to **signal in advance** the potential need for additional investment at a GSP to those parties who are in a position to consider actions to avoid or reduce this investment. This might be:

- DNOs – through (planned) lower cost investment (than transmission) in their networks through (planned) reconfiguration of their network

- Generators – who are considering siting decisions and have some flexibility of location within a DNO network OR are given connection offers by a DNO which take into account differential network investment/configuration options to reduce/avoid particular levels of export from Relevant GSPs

It needs to be considered how a lower cost investment solution by a DNO (than the transmission network owner) would be triggered, how the differential benefit might be calculated and how approval for the DNO investment would be gained. Appropriate cost recovery by the DNO across its charging base would also need to be considered. In the example above, there might be an option for the DNO to recover part of the identified investment costs from specific generators

Assuming that an efficient mechanism can be put in place to ensure that the optimum investment decisions are made (either DNO or generator location), there will still be the potential for GSPs to require additional investment (at some point) by the transmission network owner.

We note that the majority of transformers at GSPs are categorised as connection assets as they are used by a sole party (the local DNO).

“Where there are GSPs which are used for the connection of more than one party (multiple DNOs at the GSP, or the GSP supplies a DNO and a generator) 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.”

- We note the possibility of this differential charging treatment. However, it is the product of a particular methodology rather than an unavoidable conclusion. It could equally be argued that in the case of multiple users, the assets are shared connection assets and that the

methodology has not yet been sufficiently developed to correctly apportion the connection asset costs appropriately, rather than automatically allocating any costs to wider TNUoS infrastructure charges. Conversely, a GSP has traditionally been established as a connection between one network and another, rather than an individual user. As such an argument can be made that it is not a sole user asset and should be recovered via infrastructure charges.

- NGET allude to the possibility of individual charge allocation when discussing options for the local charge at infrastructure GSPs. “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.”

Given that the growth in distributed generation is likely to continue and that flows onto the transmission system from the distribution system will also continue (and likely increase), consideration of distributed generation as “negative demand” is no longer appropriate.

The options presented in the informal consultation paper 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. As such, the options are limited to consideration of an extension to the local TNUoS charging arrangements to exporting GSPs on this basis. If an exporting GSP were indeed equivalent to a generator, then it is unclear why the proposed charging changes have been limited to consideration of the local TNUoS charge. In order to ensure equivalence, it would be expected that wider TNUoS generation charges would also be applied. This would have the effect of incentivising GSPs to export in negative generation TNUoS zones relative to those in positive ones. It is unclear exactly how the generation and demand TNUoS charges would interact and what “netting” algorithm would be used. For the sake of clarity, we are not advocating the application of wider generation TNUoS to exporting GSPs – as they are not equivalent to a transmission connected generator.

It is not appropriate to consider an exporting GSP to be the equivalent of a generator (apart from the special cases in the Appendix to this document). The export is the product of a complex and changing demand/generation balance. In a mixed and substantial DNO network:

- Exports cannot be attributed to a single generator where there are several active. Even if demand where a constant, different combinations of generators/outputs may be responsible for equivalent export at differing times
- There are differing methods of allocating “export” responsibility across multiple generators (last connected, load factor, output at system peak, simple average etc)
- Export may be caused by a decrease in demand rather than an increase in generation
- Export may significantly reduce or cease, due to changing demand patterns
- The level of export is not directly correlated with generator output, as it would be for a pure generation only connection
- The export generation is not subject to single direct control actions, or to dispatch instructions from the system operator, as a generator only source would be.

The GSP may be considered to be an unmodulated interconnector, in that flows are largely outside of the operator’s control unlike (e.g.) an HVDC interconnector.

Transmission charging for generation is based upon capacity, rather than usage. Other interconnections between different network systems break down capacity usage into appropriate time periods to arrive at a reflective cost/usage charging structure. As such, for exporting GSPs the solution would be to measure export by half hour and allocate to distributed generation by output in that half hour (taking into account how far “up/down” in the DNO system it was).

Answers to Informal Consultation Questions

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

Need to recognise that the growth in distributed generation is changing the nature of distribution networks and power flows both within them and between the T & D systems and (to varying degrees) on the transmission system.

The issue is not exporting GSPs per se but more to do with the changing nature of interaction between the Distribution and Transmission networks. As such, it is necessary to ensure that strategic and wider policy issues are considered such that any changes to the charging arrangements for GSPs are consistent with overall government energy policy objectives (e.g. promotion of renewables/local energy/distributed generation) and do not have to be revisited in the near future.

It is also important to understand the way in which both Transmission and Distribution networks will evolve over the coming years. It is not necessary to specify detailed outcomes. However, there will be certain baseline assumptions and challenges which will need to be addressed:

- Two way energy exchange will increase between the T&D networks
- D networks will become “smarter”. They are already “active” and at some point they will need to be actively managed
- Distributed generation can no longer simply be treated as negative demand.
- More sophisticated frameworks are required for planning and operation of the D network and the T/D interaction

Although not covered by charging proposals for exporting GSPs, the issue of network operations and the interaction between networks is central to this matter and cannot be ignored (we cover this later)

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

We do not consider that this is the correct question to ask. The principles of energy exchange between the two networks and the cost recovery of the relevant assets involved need to be discussed and agreed before moving to specifics such as the use of local TNUoS to address a specific issue associated with the growth of distributed generation. Of equal importance is the need to understand the requirements for investment ahead of need in this area and the challenges of operating both T and D systems interactively and efficiently in the future.

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

National Grid notes that these local charging options would reflect the incremental cost of an exporting GSP on local transmission infrastructure. We have already noted that NGET consider an exporting GSP to be equivalent to a generator. If this were the case then the impact on the wider system would also be taken into account (Presumably by the transport and tariff model used in the derivation of TNUoS). This is not proposed and we do not believe it to be appropriate. As such, the proposal to use the local charging mechanism represents an incomplete consideration of the actual impact of exporting GSPs on the transmission system and as such needs to be reconsidered against the wider context of the issues discussed in 3.1 and 4.1 above.

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

We agree that the DNO is the appropriate party to take responsibility for any charges involved in the development of network to network interfaces. However, as already stated, we do not endorse this particular charge and we believe that the allocation of any charges by the DNO requires joint consideration and engagement with stakeholders prior to any implementation. We are also concerned that the DNO may not currently have the information/capabilities to pass through any charges of this nature in an equitable manner to final users of its network.

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

It has already been noted that the proposed local charging options would reflect the incremental cost of an exporting GSP on *local transmission infrastructure*. As we have noted above, this is an incomplete picture in that the exporting GSP will have an impact on the *wider* transmission system which has not been considered.

We agree that the use of historic metering data appears to be a reasonable basis on which to determine (eventual) costs and benefits.

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

“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 understand why this approach has been considered, based on the maximum export figure. It has the virtue of simplicity. However, it is not necessarily accurate. It is inappropriate to consider an exporting GSP to be the equivalent of a generator (apart from the special cases in the Appendix to this document). The export is the product of a complex and changing demand/generation balance. In a mixed and substantial DNO network:

- Exports cannot be attributed to a single generator where there are several active. Even if demand where a constant, different combinations of generators/outputs may be responsible for equivalent export at differing times
- There are differing methods of allocating “export” responsibility across multiple generators (last connected, load factor, output at system peak, simple average etc)
- Export may be caused by a decrease in demand rather than an increase in generation
- Export may significantly reduce or cease, due to changing demand patterns
- The level of export is not directly correlated with generator output, as it would be for a pure generation only connection
- The export generation is not subject to single direct control actions, or to dispatch instructions from the system operator, as a generator only source would be.

We have already stated that we believe the basis of the charge needs to be reconsidered. Any network to network charge eventually deemed appropriate would be more equitably allocated if it referenced the impact of individual users on a more specific basis.

The GSP may be considered to be an unmodulated interconnector, in that flows are largely outside of the operator’s control unlike (e.g.) an HVDC interconnector.

Transmission charging for generation is based upon capacity, rather than usage. Other interconnections between different network systems break down capacity usage into appropriate time periods to arrive at a reflective cost/usage charging structure. As such, for exporting GSPs the solution would be to measure export by half hour and allocate to distributed generation by output in that half hour (taking into account how far “up/down” in the DNO system it was). The individual charges for half hour(s) would then be scaled to ensure that gross charges and costs were equivalent

over relevant charging periods (e.g. one year with k factors). We recognise that this is a level of charging granularity is currently not used. However, given the need to increase the quantity and granularity of data in DNO networks for many other objectives, this should not be insurmountable.

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

Before considering changes to the definition of a MITS node (which is a significant step and should not be undertaken lightly), we repeat that the basis of energy exchange between two connected networks needs to be considered in the round, rather than narrowly confined to the issue of “exporting GSPs”.

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

NGET state: “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.”

We disagree with this statement. Even where a GSP exports (provided it is not above the capacity/capability of the assets), the benefit of distributed generation remains. Without the distributed generation, reinforcement for additional demand would indeed occur sooner than otherwise, GSP exporting or not.

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

Exporting GSPs are not generators; they are network energy exchange points. Applying generation based local circuit charges is inappropriate.

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

Charges should be based on the principles of network energy exchange and consider wider issues than just local infrastructure before determining the level and structure of any charges (and importantly, benefits). We support the principle of cost reflective charges and have commented above that appropriate signals need to be provided in advance, both to DNOs and users of their networks such that optimum decisions on network investment, configuration and generation siting can be made BEFORE charges are levied by the transmission owner.

As always, a fundamental principle is that those users who have made decisions based on arrangements existing at the time of those decisions should not face discriminatory additional charges due to subsequent changes in frameworks/charging methodologies etc.

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?

BSUoS is long overdue for reform (user views.....)

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?

Yes, but it is a matter of scope and scale – at some point NGET will need an aggregator

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

Whoever has the primary relationship with them – supplier or offtake/contractual party

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

Not your job to solve all the issues, so think as wide as you like. Much more helpful if NGET put effort into detailed problem definition that solution providers can then work against, rather than trying to guess all outcomes.

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

It certainly needs the principles of energy exchange between networks to be discussed and agreed by stakeholders – once that is sorted charging is an important part, but equally important is control and operation – which should be considered in the round.

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?

No – nice try, but using a spanner to solve a problem just because it is the nearest tool to hand does not work when the requirement is for a router

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?

Lobby Ofgem to “power up” the DNOs. They do not have to be the exclusive route to all solutions, but without a DNO that can manage, control, monitor and operate a modern active distribution network, you will not get very far.

Additionally, we would be disproportionately impacted if the exporting GSP charge were to find its way to the generator, we have GSPs where we are the only connectee and so we cannot avoid it. Apply charges that we cannot respond to and to see a charge that was not visible at the investment decision will harm our business.

Graeme

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Mr D Corby
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31 October 2015

Dear Mr Corby,

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

Thank you for the invitation to respond to the above informal consultation paper. Good Energy is a fast-growing 100% renewable electricity company, offering value for money and award-winning customer service. An AIM-listed PLC, our mission is to support change in the energy market, address climate change and boost energy security.

Executive Summary

Growth in exporting GSPs is likely to be significantly reduced due to massive Government cuts in subsidies for renewable generation which undermines the case for developing charges for exporting GSPs.

Any local TNUoS charge introduced should be:

- cost reflective, transparent, minimise as far as practicable volatility of charging, be relatively simple to apply and allow users to forecast their charges;
- levied on Distribution Network Operators so as to provide them with appropriate signals for:
 - managing their networks and potentially facilitating a transition to smart networks and becoming Distribution System Operators in Great Britain;
 - making least cost choices between investment in distribution system reinforcement and additional charges for increased capacity at GSPs;
- structured so end users could respond to the price signal. This would require major change to distribution use of system charging to enable the charges to reflect the variation in TNUoS charges across GSPs within each GSP Group.

EU network codes are due to be implemented over the next couple of years bringing significant changes to the current code structure. In view of this we consider that no significant changes to the transmission charging arrangements should be considered until these codes are in place.

Consultation Questions

Our response to the specific questions raised in the informal consultation paper is set out below.

Drivers for our Work

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

The data presented of the number of exporting GSPs in 2013/14 and 2014/15 shows this to be only a significant issue in Scotland and we think it would be helpful if the data for Scotland was also presented on

the same basis as for the rest of Great Britain, namely for the interface between the 132kV and the 275kV/400kV networks.

We believe that projected growth in exporting GSPs is likely to be significantly reduced due to massive Government cuts in subsidies for renewable generation, which undermines the case for developing charges for exporting GSPs.

The EU network codes are due to be implemented over the next few years bringing significant changes to the current code structure. In view of this we consider that no significant changes to the transmission charging arrangements should be considered until these codes are in place.

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?

In principle we consider that, if local TNUoS charges were introduced, they should not be limited to those GSPs which export power onto the transmission network but should apply to all GSPs in Great Britain. We note that National Grid has not considered extending local TNUoS charging arrangements to importing GSPs on the basis that 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. We question the rationale for this, it being founded on the belief that it is appropriate for circuits which connect remote communities to the transmission system not to bear the cost of that local connection.

Charging for both importing and exporting GSPs would incentivise the minimisation of power flows through the GSP and the consequential reduction in electrical losses.

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

We consider the Distribution Network Operator (DNO) to be the appropriate party liable for a potential TNUoS local charge.

Actions by the DNO or by users of the distribution network can impact whether or not a distributed generator (DG) is exporting onto the transmission network. For example, the DNO could close circuits that isolate the generator from local demand, or a local manufacturer could close down causing a reduction in local demand. Both could turn a DG from not exporting through the GSP, to exporting through the GSP, although the DG has not changed its behaviour. By making DNOs the charge payer DNOs would be faced with appropriate signals for managing their networks and making least cost choices between investment in distribution system reinforcement and additional charges for increased capacity at GSPs. It could potentially also help facilitate a future of smart networks and a move towards a Distribution System Operator (DSO) model in Great Britain.

DNOs already have a commercial arrangement in place with all DGs and large demand users covering the terms of the connection to their network. DNOs are also far less likely to become insolvent than electricity suppliers or third party aggregators.

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

Using historic data would mean:

- new generation not being attributed any charge in the charging period immediately following its commissioning;

- charges wrongly being attributed to generators which were being de-commissioned in the charging period;
- charges potentially being affected by system outages that altered the normal level of import/export at GSPs.

Hence we favour the use of forecasts for the charging period such as the week 24 data provided by DNOs to National Grid under the Grid Code.

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

The charging base proposed in the consultation seems appropriate for determining potential local charges at exporting GSPs. A similar approach would seem appropriate for local charges for GSPs with a maximum import higher than the maximum export (with the charge also being based on the difference between the GSP's maximum import and its maximum export), which ensures consistency in the charging arrangements across all GSPs. This approach avoids step changes in charges as GSPs move from being importing to exporting (or vis-versa) and so minimises volatility in charges to users.

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

For shared exporting GSPs we would prefer the charge to be allocated between each DNO based on a forecast for the charging period of their maximum export in any settlement period, rather than using metered data for the previous year. A similar approach should be used for shared importing GSPs, with the charge allocated between each user based on a forecast for the charging period of their maximum import in any settlement period. Using metered data for the previous year has the unwelcome effect of charges potentially being affected by system outages on the networks of the DNOs at shared GSPs. An alternative approach which should be considered is to use metered data for the charging period.

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

We believe that further consideration of the MITS node definition is needed to enable local circuit charges to be applied on a consistent basis for both importing and exporting GSPs and for transmission connected generators.

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

We consider that any local substation charge for exporting GSPs should preferably also apply to importing GSPs and provide appropriate signals to DNOs for managing their networks and making least cost choices between investment in their networks or paying for investment at GSPs, thereby minimising overall costs to users. Any local substation charge for GSPs should be costed on a consistent basis to local substation charges for transmission connected generators but would need to be charged out to DNOs on a different basis if the charge is to be passed on equitably to DNO network users and provide an appropriate signal they can respond to, as explained in response to Q4.9 below.

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

Any local circuit charge for exporting GSPs should preferably also apply to importing GSPs and be costed on a consistent basis to local circuit charges for transmission connected generators. It would need to be charged out to DNOs on a different basis if the charge is to be passed on equitably to DNO network users and provide an appropriate signal they can respond to, as explained in response to Q4.9 below.

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

Any charging methodology put in place to recover local TNUoS charges needs to be transparent, minimise as far as practicable volatility of charging, be relatively simple to apply and allow users to forecast their charges. To be effective in providing cost signals to end users, they also need to be able to respond to the charges.

One approach would be for the local TNUoS charge to be on the basis of kW or kWh of demand or export during periods of 2 to 3 hours corresponding with times of potential maximum import or export of the GSP. This would be cost reflective but also provide more stable charges than if they were targeted solely at times of individual GSP peak import/export, the times of which might then move as a result of user response to the charge. Time of day charging should be applied such that solar PV generation, for example, would not pay for GSPs exporting during hours of darkness.

However, the above approach would require major change to the present basis of distribution use of system charging to enable the charges to end users reflect the variation in TNUoS charges across GSPs within each GSP Group. Users would need to be assigned to a GSP, a potentially major task at the outset and also ongoing with some users likely to move between GSPs following changes in circuit feeding arrangements.

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?

The costs of operating a transmission network are primarily driven by the physical flows across the network, being caused by the net effect of generation and demand connected to it. Hence suppliers should always be charged BSUoS on the basis of their demand net of distributed generation and not for their gross demand. Were charges to be applied on a gross (not net) basis:

- it would introduce perverse incentives to create private distribution networks specifically for the purposes of enabling the metering at the interface between the private and DNO networks to measure demand net of distributed generation on the private network, thereby paying transmission charges on a net demand basis;
- for consistency, transmission connected generation should not be allowed to continue to take advantage of Trading Unit benefits under which they net off on-site demand for transmission charging purposes.

Whether or not the System Operator is procuring services from parties we consider being of no relevance as to whether or not they should pay BSUoS charges. However, were parties from which services were procured to have to pay BSUoS charges, the parties would simply pass back the charges in their contract price for the service – a zero-sum game.

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?

Rather than introduce further commercial arrangements with both distributed generation and responsive demand, we believe it would be more cost effective for National Grid to work with DNOs to best manage

both distribution and transmission networks. DNOs would already have a commercial arrangement in place with the user covering the terms of the connection to their network.

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

We believe the most efficient party is likely to be a DNO (acting as DSO), or alternatively a third party aggregator contracting with National Grid. This is generally likely to be more cost effective than National Grid contracting directly with the DG, particularly in the case of smaller scale generation.

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

As part of its initiative to promote 'flexibility' Ofgem plans to encourage the transition of DNOs to DSOs, so we think it unwise to limit consideration of models to those solely involving an aggregator.

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

No; any fundamental changes to TNUoS arrangements, or indeed to any part of the transmission charging arrangements, should only be considered once the new EU network codes are in place.

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?

We are not convinced that the options laid out in section 4 help move arrangements towards those required in the future because:

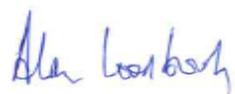
- growth in exporting GSPs is likely to be significantly reduced due to massive Government cuts in subsidies for renewable generation, which undermines the case for developing charges for exporting GSPs;
- we do not know to what extent DNOs will be able to manage their networks in response to the price signal;
- of the potential difficulty in reflecting the price signal in distribution use of system charging to enable end users to react to it appropriately, as explained in response to Q4.9;
- other outcomes may be more appropriate following:
 - a review of the present disparity in the transmission charging arrangements between Scotland and the rest of Great Britain due to 132kV transmission being part of the transmission system in Scotland but part of the distribution system elsewhere, as discussed in response to Q5.7 below; the data presented of the number of exporting GSPs in 2013/14 and 2014/15 shows it to be only a significant issue in Scotland;
 - implementation of the EU network codes.

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?

At present there is a disparity in the transmission charging arrangements between Scotland and the rest of Great Britain due to 132kV transmission being part of the transmission system in Scotland but part of the distribution system elsewhere. This should be reviewed to allow all network assets to be charged in a consistent manner across Great Britain - but not until the new EU network codes are in place.

I hope you find this response useful. If you have any questions, please do not hesitate to contact me.

Yours sincerely,

A handwritten signature in blue ink that reads "Alan Goodbrook". The signature is written in a cursive, slightly slanted style.

Alan Goodbrook

Senior Trading Analyst

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22nd October 2015

Sent via email to: dave.corby@nationalgrid.com

Dear Mr. Corby,

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

I am writing in response to the above consultation, which asks for industry views on potential Charging Arrangements at Exporting Grid Supply Points.

Haven Power is a Drax Group company and is a non-domestic electricity supplier that has been supplying Small Medium Enterprises (SME), including microbusinesses since 2007. In 2009, we entered the Industrial & Commercial (I&C) sector and have been steadily growing our customer base in both areas and currently supply ~29,000 and ~9,600 MPANS in the SME and I&C sectors respectively. We would like to respond to some of the questions raised in your consultation and provide responses in Appendix 1 which follows this letter.

We recognize the need to develop charging arrangements for Exporting Grid Supply Points and agree with a lot of your suggested ideas. We would however like to reiterate that to us the stability and predictability of tariffs is fundamentally important to us as a supplier.

With the potential for the introduction of any new methodology in calculating TNUoS charges it is vital that any step changes in tariffs are kept as small as possible and notified well in advance.

We have worked with npower and EDF energy to raise the CUSC modification CMP 244. The greater notice period of TNUoS tariff changes that this modification proposal will bring is beneficial to our customers as we would be able to price a lower TNUoS risk premium into their contracts.

I hope you find our response useful. Please contact me using the details below if there is any aspect you would like to discuss further.

Yours sincerely

Karl Maryon
Non-Energy Cost Analyst
Email karl.maryon@havenpower.com
Direct Dial (01473) 237874

Appendix 1

Q4.1	<p>Do you agree that any local TNUoS charging option should be limited to those GSPs which export power onto the transmission network?</p> <p>Yes.</p>
Q4.2	<p>Who do you believe is the appropriate party liable for a potential TNUoS local charge?</p> <p>We believe your third option with the Distributed Generator liable for a potential TNUoS local charge is the better option. Prospective new generators would then directly receive a financial signal of the impact of their development on future transmission investment.</p>
Q4.3	<p>What are your views on using historic metering data to determine the charging base?</p> <p>We believe that using historic metering data to determine the charging base is the appropriate way forward and that only those GSPs which would be reinforced on an incremental basis should be liable for the charge.</p>
Q4.4	<p>Do you have any comments on this approach to the potential calculation of a charging base for these options?</p> <p>We believe this approach is the right one. Stability of Tariffs is fundamental to us as explained within our covering letter.</p>
Q4.5	<p>Do you have any comments on our proposed approach to transformers at shared exporting GSPs?</p> <p>No specific comment.</p>
Q4.6	<p>Do you have any comments on the potential change to the MITS node definition?</p> <p>No specific comment.</p>
Q4.7	<p>What are your views of potential local TNUoS charging option 1?</p> <p>No specific comment.</p>
Q4.8	<p>What are your views of potential TNUoS charging option 2?</p> <p>No specific comment.</p>
Q4.9	<p>Do you have any comments on potential options for a recovery mechanism for any local TNUoS charge passed through to a DNO?</p> <p>We agree that the costs should be borne by the party who can respond to the charging signal and do not believe that the socialisation of an exporting GSP charge across the entire charging base of a DNO would be appropriate.</p>
Q5.1	<p>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?</p> <p>We do not believe the current BSUoS arrangements are appropriate. As the proportion of distributed generation grows larger, National Grid will increasingly need to explore options to</p>

	efficiently balance the system using services procured from distributed generation. Introducing commercial arrangements with these generators means better access to their services providing a more efficient solution for the end consumer.
Q5.2	<p>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?</p> <p>We agree National Grid should be looking at further commercial arrangements with both distributed generation and responsive demand.</p>
Q5.3	<p>Who do you believe could be an efficient party to assist in the procurement of balancing services from distributed generation?</p> <p>No specific comment.</p>
Q5.4	<p>Do you believe our thoughts should be limited to models considering an aggregator at this time?</p> <p>No specific comment.</p>
Q5.5	<p>Do you believe wider TNUoS arrangements should be reviewed to more appropriately account for distributed generation and responsive demand?</p> <p>Yes.</p>
Q5.6	<p>Do you believe the potential local TNUoS charging options (laid out in section 4) help move arrangements towards those required in the future?</p> <p>Yes.</p>
Q5.7	<p>Do you believe we should be considering any other changes to transmission arrangements to facilitate access to services from distributed generation and responsive demand?</p> <p>No specific comment.</p>



dave.corby@nationalgrid.com

30 October 2015

Dear Mr Corby

Open Letter: Potential Transmission Charging Arrangements at Exporting Grid Supply Points

Introduction

Thank you for providing the opportunity to respond to this open letter consultation on *'Potential Transmission Charging Arrangements at Exporting Grid Supply Points (GSPs)'* issued on 06 August 2015. Within this document we set out our position.

Highlands and Islands Enterprise (HIE) is the Scottish Government's agency responsible for economic and community development across the North and West of Scotland and the islands.

HIE along with its local partners: the democratically elected local authorities covering the north of Scotland and the islands: Shetland Islands Council, Orkney Islands Council, Comhairle nan Eilean Siar, Highland Council, Argyll & Bute Council and Moray Council make representations to key participants on behalf of industry to influence the way in which grid construction is triggered, underwritten then accessed and charged for in the region.

General comments regarding exporting GSPs

We welcome the opportunity to discuss and develop transmission charging methodology. HIE is supportive of National Grid's focus on ensuring that the methodology is maintained and reviewed.

HIE considers that changing the charging arrangements to account for exporting GSPs, in the manner described within this open letter, is likely to make the charging arrangements for distribution customers more complex, and the arrangements overall unduly complex. Therefore, the proposals are less likely to result in better facilitation of competition, and efficient and coordinated development of the transmission system.

Further, we consider that the proposals within this consultation have significant risk of unintended consequences on distribution customers. The risk is particularly acute without a full and robust impact assessment of these proposals on distribution charging.

HIE notes that the basis for many of the proposed changes is that an exporting GSP is no longer like a normal GSP, but more like a generator, for charging purposes. We do not believe that this assertion is supported by any of the evidence presented in the open letter.

Furthermore, National Grid has presented no substantive evidence that exporting GSPs have a significant impact on the transmission system.

HIE also notes that there is no consideration throughout the document of the fundamental differences between the classification of transmission and distribution assets in England and Wales compared to Scotland. This is a particularly important point as almost all of the GSPs – defined as exporting in the open letter – are located in Scotland.

Finally we note that National Grid's 'informal consultation' appears to cover a number of issues which should probably be consulted on separately, namely:

- Exporting GSP and transmission charging
- Contracting of balancing and other services
- BSUoS
- Responsive demand

We look forward to seeing the results of the consultation in due course.

Yours sincerely



Elaine Hanton

Joint Head of Energy

In partnership with:

Shetland Islands Council

Orkney Islands Council

Comhairle nan Eilean Siar

Highland Council

Argyll & Bute Council

Responses to consultation questions

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

We understand National Grid's concerns with the continued growth of distributed generation in general terms.

However, we do not believe there is sufficient evidence that its impact is significant enough to merit a change to the transmission charging methodologies or further work on this.

The focus on exporting GSPs also appears discriminatory when a distributed generator connecting under an importing GSP will have the same net impact as one connecting under an exporting GSP.

Moreover, it has not been made apparent why there is a focus on local transmission assets. The letter has also not clearly defined what the extent of local infrastructure assets have been or are being progressed because of 'exporting' GSPs. Therefore, it is difficult to rationally assess the drivers for changing the charging arrangements for local tariffs.

Furthermore, there is no indication why the proposed method of directing local transmission charges at DNOs (whether they are exporting or importing) would provide better investment signals or better meet the licence objectives of National Grid.

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

The rationale for the differentiation between the treatment of generation and demand customers with respect to local transmission charges is very unclear, nonetheless, HIE strongly supports National Grid's policy to avoid directing disproportionately high transmission charges on vulnerable, remote communities.

The proposed differentiation between GSPs based on the direction of power flows is also confusing given net impacts on the wider transmission are not dissimilar. Overall, the transmission impacts at a local level are much more location specific than recognised by National Grid and it is quite possible an export from one GSP could serve to offload transmission at a nearby importing GSP. We do not find the basis of the proposals clear or well informed.

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

The key contractual relationship is between the DNO and National Grid. However, from a regulatory perspective, DNOs are not yet in a position to actively manage the power flows at grid supply points (notwithstanding current efforts to develop active network management schemes).

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

HIE considers that this approach seems reasonable, from a high level.

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

HIE considers that rather than focusing on a single calculation method, the principles and method of calculating the charge should be considered fully during a formal CUSC modification and looked at alongside the potential impact on distribution customers. The methodology should be entirely consistent with that applied across the board. Unfortunately it appears NGET is developing a somewhat ad hoc method which in our view will raise questions of discrimination.

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

HIE consider that, similar to the calculation of the charging base, this is a detail that should be explored as part of the formal CUSC modification process. Albeit, the impact is likely to be small given the number of potential users that it may affect and introducing a new charging variable for one user seems inefficient and disproportionate.

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

HIE is concerned about changing the definition of MITS node for charging purposes as proposed by NGET. No evidence has been provided to support the claim that the change will not have an impact on existing generators. HIE is also unconvinced of the need or justification to change the definition.

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

HIE considers that there seems to be little justification for discriminating between GSPs with regards to the application of local TNUoS. However, option 1 is particularly strange as this charging option is not consistent with any existing charging arrangements and we therefore cannot see how this better facilitates National Grid licence objectives.

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

As per the response given to question 4.7.

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

The options for how the DNOs pass through any new transmission charges needs to be considered in full as part of a DCUSA modification process. Whether or not the charges are socialised or not must be formed independently from any CUSC modification process, albeit the impact assessment of CUSC modifications must consider the potential impact on distribution customers. Previous CUSC modification processes have failed to adequately consider and accommodate for the potential impacts on DNO customers. A clear example of this failure is CMP192, which needed a subsequent further modification to address the deficiency created.

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?

HIE notes that distributed generators are exposed to BSUoS liabilities, depending on their contractual relationship with National Grid and/or through their supplier arrangements. During settlement periods when GSP groups are in delivery mode (exporting), the generators within that balancing group are exposed to BSUoS.

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?

HIE would welcome further exploration of potential new commercial arrangements for the procurement of balancing services from alternative suppliers, including distributed generation and responsive demand. However, balancing contracts with embedded customers need to be considered in the context of increasing active network management at distribution level. In addition to the potential for DSOs (who may set up similar contracts with service providers within their networks) who are able to manage the power flows interface between transmission and distribution.

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

It is not clear why introducing a third party to assist with the procurement of balancing services would be more efficient. Nonetheless, provision of services from distributed generation needs to be coordinated with any services that the generator has already contracted with the distribution network operator.

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

Wider zonal TNUoS already accounts for embedded generation as part of the exit charges. HIE supports changes to the charging methodology that better meets National Grid's licence objectives. We consider that the current methodology facilitates well these objectives, and it is not clear what could be reviewed to 'more appropriately account for distributed generation and responsive demand.' Therefore, we are not supportive of further reviews to the wider charging methodology.

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?

HIE does not believe that the proposals set out in section 4 are going to result in a methodology that will be more stable and encourage competition.

- There is no material consideration of the impact on demand users and the charges that they will face. Clarity on this point is extremely important.
- Charging in the future is likely to be significantly influenced by EU policy. It is not clear how this proposal will fit under the EU directive limiting charges for generators to €2.5/MWh.
- There is significant uncertainty going forward and investment decisions on projects will be further undermined if charging arrangements are again reviewed.

- The scale of investment decisions based on the exporting power flows from GSPs has not been addressed within the paper. This makes it difficult to judge the need for changes to the charging regime.

Much of the justification is based on the forecasted future change in generation makeup, which HIE supports and considers a good and strong approach. However, significant shifts in political landscape may change the outlook for penetration of further distributed generation.

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?

In order to provide balancing services to National Grid, embedded projects are currently required to enter into a BEGA or specifically seek to vary a BELLA, which bring certain technical requirements. Other than this, it is unclear what other routes to market exist for service providers connected at distribution. The current options, suitability going forward and potential changes required should be addressed alongside any future changes to the transmission charging regime relating to distribution.

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30 October 2015

Andrew Wainwright
National Grid

Email: andy.wainwright@nationalgrid.com

Dear Andy,

Informal Consultation on Potential Transmission Charging Arrangements at Exporting Grid Supply Points

The Infinis group of companies is delighted to enclose our response to the National Grid consultation on exporting grid supply points

We have invested heavily in a broad portfolio of renewable technologies encompassing landfill gas, onshore wind and more recently hydro. As a result, we currently operate 585MW of renewable capacity across 137 sites in the UK. Our UK operations benefit from a sophisticated 24/7 environmental compliance and plant performance monitoring and optimisation system developed internally and based in our Northampton head office.

As a key stakeholder in the renewables market (generating around 10% of the UK's renewable electricity) we support any plans which will improve stability and more accurately reflect the costs imposed by different parties on the electricity system. We do have concerns with regards to the 'informal' nature of this consultation as we believe this is an extremely important issue and we feel that many stakeholders will not understand the use of the word informal in this context and as such may be less likely to reply.

We are of the opinion that a wider ranging review of network charging and operation is necessary and we are concerned that this particular consultation deals with relatively niche issues and risks ignoring larger issues. In particular we are interested to see how this interacts with European proposals for grid charging along with how this will affect such key issues as the G:D split.

We look forward to a positive outcome from this consultation which comes at a time when the UK electricity industry is already undergoing significant change and faces a great deal of regulatory and investor uncertainty and we would hope that National Grid keep this in mind with any future proposals. Should you have any questions in relation to our views please contact Christopher Granby on 01604 662425.

Yours sincerely,

Steven Hardman
Commercial Director

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

We are in agreement that National Grid should periodically perform internal reviews to ensure that they continue to meet their licence obligations. However, in this case we see no changes of sufficient magnitude to have warranted this 'informal' public consultation.

In particular we believe that the drive by National Grid to charge distributed generation for Transmission costs is both unnecessary and unfair. In particular we believe there are several existing conditions which render further charges on distributed generators unreasonable:

- Distributed generators generally have no option of Transmission or Distribution when deciding to connect to the network. They connect to whichever is most convenient for the DNO/SO. This will usually, but not always, be driven by the voltage required for the generator to connect.
- Distributed generators already pay the full cost of all sole use assets within the DNO area
- Transmission connected generators receive the benefit of using the distribution network to service the end users without contributing to the installation or operating costs.
- Distributed generators have no TEC rights and indeed can be shut down via emergency instructions from the SO
- Distributed generators sell all of their output to licensed suppliers. It is the responsibility of the suppliers whether this power needs to access the transmission network.
- Distributed generators provide power locally and reduce the need for wider transmission reinforcement
- The transmission network ultimately exists to provide electricity to demand customers. Generators costs should be limited to the sole use costs of connecting them to the network

We do not believe that anything has fundamentally changed and as such there is no need for a wider consultation into exporting GSPs or TNUoS charges.

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

We are not in favour of any fundamental change to the TNUoS charging regime. The only changes which should be considered at this time are changes to the G:D split which should move away from charging generators.

Any investigation into exporting GSPs should be limited to those which have a typical export which is higher than its import but only those where this is the case at the peak TRIAD periods as this forms the basis for the charging.

In addition we believe that the scheme should also have a capacity threshold. For example it is not feasible to say that a GSP which imports 75MW but exports 80MW has been reinforced purely for purposes of export. We would suggest that the peak export must be at least 25% higher than the peak import before it could be considered to be an exporting GSP.

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

It would appear that there are three options on parties liable for charging, DNOs, suppliers or generators.

The least logical proposal would be the generators. Generators have no contractual relationship with National Grid nor with the end user. They have no rights to use the transmission network, they can

be shut down via emergency instructions and have no input into where their supplier ultimately decides to supply the electricity. You could potentially make a case for generators who have entered into BEGAs or BELLAs to be liable for these charges but these same generators will then be eligible for turn down payments.

It would seem sensible for the liable party to be the DNOs. The DNOs own the GSP and have a contractual relationship with the SO. The DNO would then need to pass these charges on to its own customers via a charging framework although presumably generators would expect the same exemptions as offered through the DUoS regime. This is due to the fact that many generators paid 'deep' connection charges which included ongoing use of system rights.

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

Using historic data would appear to be the most sensible option for determining the charging base. Another option would be to use a forecast of GSP output although this seems prone to inaccuracy and seems to offer little advantage.

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

As outlined in question 4.1 we believe that a GSP must be 'significantly' exporting before it could be described as an exporting GSP. As such we propose that any proposals are limited to GSPs which export at least 25% more peak power than they import.

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

The consultation states that there is only one such transformer in GB which would be liable for this treatment and as such it seems unnecessary to devise special rules. The cost of these transformers should continue to be socialised through the TNUoS residual charge. Any other solution introduces unnecessary complexity and potential disputes to an already very rare situation.

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

No comments.

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

The premise that distributed generators receive an 'embedded benefit' is not at all established. It is true that distributed generators do not have to pay TNUoS charges due to them not being connected to the distribution system. The absence of a charge for something you do not use is not at all the same as a benefit, if we can draw an analogy this would be akin to calling driving on the A5 in the West Midlands an embedded 'benefit' because we have avoided the M6 toll charge. The fact that SOME suppliers and generators might chose to share these cost savings does not amount to making them a benefit. In addition there is no standard for how these 'benefits' are shared. We are aware that there is a very large range on what percentage of these savings are shared ranging from 0-100%. We do not believe it would currently be possible to quantify the value of 'embedded benefits' across the industry.

In addition it is not clear that generators who connect to a DNO network would be aware if their GSP was connected to a single or double busbar substation nor what mitigation or optionality is available to them to make different decisions.

Furthermore, there appears to be an assumption that these substations have only been put in place purely to allow exporting GSPs to exist when in fact these units are of standard sizes. It is irrelevant if a GSP is exporting or importing. The costs to connect it to the transmission network will be the same.

Finally the underlying fact is that distributed generators have no TEC and can be shut down via emergency instructions. All of these rights would need to be re-examined if TNUoS charges were to be levied.

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

We refer to Q4.7 to illustrate why we do not believe exporting GSPs should be charged TNUoS. Option 2 appears to be adding the complexity that importing GSPs would in fact receive these payments as they have reduced the need for reinforcement. This would leave us in the position where over 300 GSPs would be in receipt of payments, if it could be shown that this would be passed on to generators to encourage them to generate. It could be argued that this could replace the 'embedded benefit' referred to in Q4.7 above that generators currently receive.

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

We would expect charges to be passed on to the DNO in a similar way to current exit charges. How these are then converted to distribution charges is a matter for the DNO and DCUSA.

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?

We believe that current BSUoS arrangements are appropriate. Parties who have no guaranteed rights to use the system and have no knowledge on whether they are impacting the system should continue to avoid BSUoS charges.

We welcome moves by the System Operator to engage with smaller generators and would encourage moves which saw them procure services from these generators. We believe that engaging with smaller embedded generators should be a fundamental cornerstone of any future policies.

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?

As explained in the answer to Q5.1 we believe that National Grid should be looking at this as a matter of priority. While we do not have any specific proposals we feel that it can only be positive if the System Operator is able to contract for services with a wider range of partners. In particular contracting with embedded generators for balancing services and voltage control could enable very local actions and perhaps reduce the need for wider actions or reinforcements. As an operator of around 150 embedded sites we would be happy to discuss these matters further with National Grid.

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

There appear to be three options for procuring balancing services:

- Direct from the generators

- From the DNOs
- From a third party aggregator

All three raise various challenges but we can see a viable model using any of them.

Direct from generators – This allows the generators to benefit directly from any arrangements. In addition generators are in the best position to understand what services they are able to offer at any given time. The downside is that NGC would need to enter into many arrangements with organisations of varying sizes and ability. This would probably be an option for large power stations or those generators with a large portfolio and/or a control centre.

From the DNOs – If each GSP were treated as a single entity then NGC could contract with the DNO for services with the DNO performing balancing actions as necessary. This is simple from the System Operator’s perspective but we are sceptical that the DNOs have the knowledge or infrastructure to operate such a system. In addition we are very doubtful that any benefits would pass through to generators or customers.

From a third party aggregator – This looks like the best compromise; NGC contracts with one or more aggregators who will provide balancing services to Grid. This negates the need for Grid to contract with many counterparties. In addition generators can remove much complexity by avoiding Elexon and the balancing mechanism. From a negative point of view the aggregators are going to need to take a margin from this so there will be reduced value to generators and increased costs for consumers.

We are not against any proposal but strongly favour avoiding the DNOs who are not currently well resourced to provide such services. Our understanding is that most DNOs do not focus heavily on balancing and take more of a reactive approach to managing their areas and place a higher value on ensuring that the network is robust than ensuring efficient actions are taken. We would prefer to see balancing actions taken by aggregators who well understand the requirements of generators or by the generators themselves

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

We do not agree with this. Considering this is an informal consultation and these investigations are at a very early stage it would seem premature to focus on a single delivery model. We are aware that there are several aggregators who are already marketing and lobbying for these products and we would hope that the System Operator would take a ‘big picture’ overview before settling on a solution.

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

We believe that there is no requirement to immediately change the TNUoS arrangements. These are well understood and have largely served the industry well in ensuring that there is adequate supply of energy at peak times.

Grid should limit their short term efforts on TNUoS to ensuring that the G:D split is in line with European Directives before embarking on wider-ranging reform of charging.

We do realise that in future decades as generation and demand increasingly migrates to distribution systems then the current model for funding the transmission network will become unviable. We would encourage NGC to begin work immediately on a radical overhaul of the system to better serve

the needs of industry and customers. We believe that this should take a clear and structured approach with adequate lead times and the avoidance of 'shocks' which will serve to make investors in UK infrastructure very nervous. We would not envisage these significant changes taking place before the end of the decade.

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?

It is difficult for us to determine which, if any, of the options help us to move towards those required in the future. The proposals within this consultation are at very high level and in little more than prototype form. We would require much more data along with impact studies and implementation details to make a clear view.

As detailed in response to Q5.5 we believe that NGC should be taking a more holistic overview of future needs for an efficient transmission system and avoid short term drastic changes which may lead to unintended outcomes. In addition we believe any major changes which are introduced prematurely, without adequate consultation or which alter revenue flows dramatically, will further reduce confidence in the UK energy sector. Regulatory stability and predictability are absolutely fundamental to a healthy investment sector.

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.

We believe that national grid should constantly be considering any changes which make transmission arrangements more efficient. While we have no specific recommendations we note that distributed generation can already provide responsive demand through the STOR program and the Capacity Market scheme.

An area that would appear to be rich in potential to explore would be between the DNOs and the SO. Currently it would appear that these two systems are operating almost independently of each other. It would seem that efficiencies could be achieved if there was far greater synergy between the two systems. One obvious possibility is that the operation of both networks is handled by a single body who has total oversight of the system.

Also working with embedded generators to provide Grid with generation forecasts could yield valuable results. Currently there is no obligation on generators to provide forecast or balance their portfolios. Some kind of incentive scheme for providing accurate forecast would, at first glance, appear to offer an opportunity for the System operator to receive higher quality data.

We would suggest that the System Operator holds a workshop with embedded generators to explore ways that generators could help with the current stresses that the system is under.



Andy Wainwright
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CV34 6DA

30 October 2015

Dear Andy,

National Grid open letter on potential charging arrangements for exporting grid supply points (GSPs)

We welcome the opportunity to respond to National Grid's consultation document, "Potential charging arrangements for exporting grid supply points".

The Association for Decentralised Energy, Energy UK, Renewable Energy Association, Renewable UK and Scottish Renewables are submitting a joint letter to this consultation to reinforce the fact that all significant trade associations, representing suppliers and both transmission connected and embedded generators, have a common and united view on this issue. We are giving our views on behalf of our members, who include both transmission and distribution connected generators, developers of future projects which are to be connected, and suppliers who actively buy and sell electricity from these generators and participate in the electricity market.

We have been closely involved in the recent work to consider licence condition C13 and the role of the Embedded Benefit, and as such we support the subsequent exercise to review the charging arrangements for exporting GSPs. We appreciate the time taken to meet with industry at various events and meetings and welcome the opportunity to respond to the current open letter, in advance of any modification proposals being brought to the Connection and Use of System Code (CUSC) Panel. Overall, we consider that any proposed changes must provide a solution that will result in a fairer and more cost reflective charging regime.

While we are supportive of the principle of developing charging arrangements for exporting GSPs where there is a cost impact on the network, there is some concern that the proposal in its current form does not provide sufficient information.

It is our view that a successful implementation of charging arrangements on exporting GSPs will depend greatly on a number of factors which are not yet addressed in any detail. These include:

- The proposal as set out does not provide sufficient information about how the change would be implemented and about how exporting GSPs impact transmission network costs.
- Without knowledge of how DNO's would pass charges on to connected parties it is difficult to accurately assess the options presented. This runs the risk of unintended consequences, including counter-productive charging signals. Therefore any proposals to implement a charging methodology for exporting GSPs under the CUSC should be carried out in parallel with a Distribution Connection and Use of System Agreement (DCUSA) modification. It will also be important that as much as possible the charge is forecastable for each class of user on a year by year as well as on a medium-term basis.
- The work presented does not attempt to value the impact of other changes at the DNO level, such as: more active management, demand side response providers, and load shifting. In particular it is vital that any arrangements do not create an unnecessary barrier to the development of DNO's taking on the role of DSO's (this is in line with recent statements from Ofgem¹)
- We see a significant risk that a charging arrangement that does not integrate these longer-term aims of a more flexible and responsive system into account could inhibit market participants' ability to react to short-term signals to prevent the need for additional infrastructure investment, raising the overall costs for consumers.
- While we support the principle that exporting GSPs should be charged in the same manner as a transmission-connected generator, changes to the MITS node definition would have consequences that go beyond charging arrangements. Therefore, the full implications of such a change should be considered carefully with industry to ensure they are implemented appropriately.

Therefore, we would encourage National Grid and Ofgem to work together with industry to update the current assessment to reflect these issues as a necessary next step before considering any changes to the CUSC.

Our associations have responded to the specific questions in the consultation individually.

Yours sincerely,

Jonathan Graham, the Association for Decentralised Energy
Kyle Martin, Energy UK
Frank Gordon, Renewable Energy Association
Gordon Edge, Renewable UK
Michael Rieley, Scottish Renewables

¹ https://www.ofgem.gov.uk/sites/default/files/docs/2015/09/flexibility_position_paper_final_0.pdf

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30 October 2015

Dear Andy

National Grid informal consultation on potential transmission charging arrangements at exporting GSPs

We thank you for the opportunity to provide comments on your informal consultation regarding exporting GSPs. As a Distribution Network Operator (DNO), we understand the drivers for the work described in this consultation. We have the same constraints under our licence and the Distribution Connection and Use of System Agreement (DCUSA) when addressing charging issues and changes to charging methodologies under open governance arrangements. It is therefore appropriate that you consult with stakeholders and gather their views before entering into the formal process.

We recognise that DNOs need to be moving towards a more active Distribution System Operator (DSO) type role and believe that this change should form part of a wider review of TNUoS arrangements, taking account of the other industry work associated with low carbon technologies; Ofgem's commitment along with the Department for Energy and Climate Change (DECC) to look at more flexible ways of managing how we consume and produce electricity and future proofing any changes to accommodate smart meter and smart grid solutions.

However, we must be cognisant that these proposals are at odds with our licence in terms of the ability to pass-through any additional costs and the new commercial arrangements that would need to be developed. The current regulatory framework does not facilitate this and as this is a significant change in charging arrangements we feel it should be considered as part of a broader review rather than taken in isolation.

More detailed responses to the specific questions are attached in the annex to this letter. We hope you find our contribution helpful and we look forward to hearing your conclusions on this matter.

Yours sincerely

A Jenkins

Andy Jenkins - Head of Network Trading

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ANNEX 1

Detailed response to the specific questions posed in the informal consultation regarding Potential Transmission Charging Arrangements at Exporting Grid Supply Points (GSPs)

Section 3 - Drivers for our work

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

As a Distribution Network Operator (DNO), we understand the drivers for the work described in this consultation. We have the same constraints under our licence and the Distribution Connection and Use of System Agreement (DCUSA) when addressing charging issues and changes to charging methodologies under open governance arrangements. It is therefore appropriate that you consult with stakeholders and gather their views before entering into the formal process. However, we have concerns that these proposals are at odds with our licence in terms of the ability to pass-through any additional costs and the new commercial arrangements that would need to be developed, in conjunction with Ofgem and impacted parties, to facilitate such changes.

We recognise that DNOs need to be moving towards a more active DSO type role and that this should be considered as part of the bigger picture, taking into account some of the excellent work that has already been undertaken in some of the Low Carbon Network Trials. However, the current regulatory framework does not facilitate this and as this is a significant change in charging arrangements it should be considered as part of a broader review rather than taken in isolation.

The consultation appears to jump to a conclusion that DNOs are in the driving seat for what gets connected, when actually the stimulus for distributed generation (DG) is:

- electricity supply licence holders buying the output of DNO connected supplier volume allocation (SVA) registered generators; and
- Central volume allocation (CVA) generation businesses and Balancing Mechanism Units (BMU).

Yet the option of directly charging suppliers for SVA sites who buy DG output or the owners of CVA sites are not put forward for analysis of the pros and cons.

Generators, for example windfarms, pursue sites where there is appropriate wind speed and the potential for planning consent. DNOs have little or no real influence over such locational decisions other than perhaps the connection charge, which could not accommodate pass through of these proposed TNUoS signals. In addition micro generation customers under G83 are free to connect first and notify afterwards so DNOs again have no locational influence on that DG sector either.

The DNOs existing assets are generally located where they are, due to historical factors and so are GSPs. Hence, taking all of the above into consideration the DNOs have less locational influence than some stakeholders may think. Because of the lack of locational control that the DNOs have, it can be seen that generator, operators and suppliers who purchase DG output are actually driving any grid investment caused by exporting GSPs.

Currently, based on the scenarios presented in this paper, this appears to be a largely Scottish based issue that may not warrant a national solution to changes in charging at this stage. The consultation only provides two potential options and we feel there would be benefit in exploring other future scenarios before drawing any firm conclusions. We note that you expect to see growth in small scale generation, however this may not come to fruition in the near future as a result in changes to incentive mechanisms and as businesses look to utilise on site generation to off-set their demand, again it may not result in net export of any significant

magnitude. We would therefore like to see more analysis and understand in more detail if there is a tipping point at which this becomes an issue in its own right.

Identifying the parties responsible for driving grid investment from the growth of DG and communicating cost signals to them may be fair in the longer term, but is difficult to see how it is the DNOs that are actually driving investment when the DNOs are simply meeting customer expectations in a lower carbon arena.

We note that National Grid already has existing contractual relationships with parties other than DNOs including for Short Term Operating Reserve (STOR) contracts and feel that this type of relationship should be explored further.

Section 4 - 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?

The introduction of any new charging arrangements needs to be carefully considered and the rules around which GSPs are impacted clearly defined. Potentially they should only apply to those GSPs that are clearly generation dominant (e.g. over 70% of the total consumption), rather than considering a positive variance between the maximum export and maximum import values, or the fact that the GSP exports in any particular time period

We note that National Grid 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. We would argue that as a DNO connecting to the transmission network, we are facilitating the connection of embedded generation which you rightly say can reduce the need for transmission investment in the majority of cases. It may be that some form of aggregation is required to help smaller generators and we should consider how this could be applied. However, at this point in time, it would seem more appropriate that National Grid enter into a contract with any generator that is deemed to be creating additional investment and offset this against any TNUoS charges that are socialised across all parties paying TNUoS, rather than socialising additional DNO costs over customers who are not necessarily contributing to this area of concern.

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

We note that you believe that there are a number of options for the appropriate party liable to pay a TNUoS local charge, but your options focus on the DNO as there are already contractual relationships in place. National Grid also has contractual relationships in place with suppliers and large generators, so it would seem sensible to also explore these options.

If this were to be considered an urgent change then we believe that given the small number of GSPs that are affected (particularly in England and Wales) that it would be more appropriate for a commercial framework to be developed directly between National Grid and these distributed generators. National Grid currently already have commercial agreements with a number of larger distributed generators, this would seem a logical extension of those arrangements. In the longer term it would be better to look at a broader more holistic approach and develop an enduring solution once there is a better understanding of the tipping points resulting from the future scenario modelling rather than a short term fix.

Alternatively National Grid could levy these charges on electricity suppliers who are the registrant for a significant number of embedded generation connections and purchase their outputs.

Contractual relationships currently exist between DNOs and embedded generators in the form of connection agreements which are put in place at the time of connection, DNOs then only enter into discussions with DG customers if they wish to make changes to the connection, we do not have enduring relationships with these customers.

Distribution Use of System (DUoS) charges are currently levied through electricity suppliers and not directly with embedded generators. The DUoS charges are governed by two approved charging methodologies the Common Distribution Charging Methodology (CDCM) and Extra-high voltage Distribution Charging Methodology (EDCM). Any proposal to pass-through TNUoS charges would require significant changes to both of these methodologies, which could be both challenging and lengthy to achieve. There would also be significant IT changes required to enable the billing of these new charges and changes would be needed to the regulatory arrangements to facilitate the recovery of these additional costs which were not part of the RIIO-ED1 agreement.

One specific area of concern is the exemption from export DUoS charges for generators connected prior to 2005. The use of time-limited exemptions was agreed by Ofgem following considerable industry consultation, as a result of the adverse reaction from the generation community to the introduction of charges, particularly those who were liable for site-specific charges under the EDCM. Many of these sites still have a significant period of exemption remaining, it would therefore seem almost impossible to reverse this and agree that they should now be subject to TNUoS charges levied by DNOs on behalf of National Grid.

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

This would seem appropriate, but other options should be explored. For example, consideration should also be given to using multiple years of historical data to avoid the potential for unnecessary volatility in charges that result from the use of an uncharacteristic year of data in isolation.

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

Only charging for the difference between the peak export and peak import values, seems the more appropriate of the two options discussed in the consultation as it is more likely to ensure that parties are not unduly charged. However, this does raise the question that, if this is a relatively small charge as quoted in your example, are the proposed options cost efficient? And do the implementation costs outweigh any potential benefits?

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

The proposed approach seems to introduce another change, where currently DNOs do not pay any connection charges for shared GSPs as these are classed as infrastructure assets. This could result in DNOs incurring additional costs for any such GSPs that are exporting.

This also raises questions on legacy agreements that have been made between National Grid and the DNO. We have one example in our Yorkshire area where National Grid upgraded an existing 132kV line to 275kV to facilitate a direct connection to the transmission network. If National Grid had not requested the change to the feeding arrangements then we wouldn't be exporting at this GSP. Currently we do not pay connection charges for this site as it is classed as shared, but if the above proposal were to be implemented then we could potentially become liable.

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

We agree that it is necessary to make the change to the MITS definition to facilitate the proposed charges and ensure consistency with the treatment of transmission connected generators.

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

To treat an exporting GSP in the same way as directly connected generators seems to reinforce that it would be better for National Grid to contract with these generators to ensure they are treated consistently. We cannot comment on any embedded benefit they currently receive from their electricity supplier.

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

As with option 1 we feel that to treat an exporting GSP in the same way as directly connected generators seems to reinforce that it would be better for National Grid to contract with these generators to ensure they are treated consistently. In addition this option puts an additional risk on DNOs who are currently connected at shared GSPs, see our response to Q4.5.

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

This is potentially the biggest area of concern for DNOs, it is not only the arrangements for allocating the costs which as you rightly say are currently socialised across our charging base, but there are implications for revenue recovery in the current price control period RIIO-ED1 which runs until March 2023. The licence currently only allows us to recover costs from National Grid for connection charges, and we can then pass these costs on to our customers, to enable us to recover our allowed revenue.

We note that you mention possible changes to your methodology would not be implementable until after 2018, however if that were the case then a change to the distribution licence would be needed to allow us to pass-through any other transmission charge that is currently levied through TNUoS, as the current regulatory settlement does not recognise this expenditure for DNOs. Taking all of this into account, if these changes were to go ahead it would seem more appropriate to develop proposals as part of a broader review with a target implementation date to coincide with the start of the next price control RIIO-ED2, which would then allow the regulatory concerns to be considered fully.

Please also see our response to question 4.2, with respect to the impact on the DNOs charging methodologies and the current exemption of export charges for pre-2005 connected generators.

Section 5 - 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?

As a DNO we are not currently liable for BSUoS charges as these are picked up by those parties who utilise and contribute to the settlement of energy on a day-to-day basis (e.g. suppliers, transmission connected generators and some distributed generators), and this seems appropriate.

As stated earlier, it may be more appropriate and cost efficient for National Grid to set up commercial arrangements with those distributed generators they believe to be contributing to any reinforcement in the same way as they enter into STOR contracts with distributed generators for providing services.

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?

In the same way as National Grid are looking at their methodology DNOs are also looking into options to manage the distribution networks more efficiently, these include time of use signals and demand side response products. It would therefore seem sensible to have a co-ordinated approach that considers the impact on both the transmission and distribution networks, as at the moment where a generator enters into a STOR contract at transmission, this would prevent a similar contract being setup at the distribution level, and a bottom up approach would then consider all implications.

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

We agree that going forward distribution networks will become more active and there may be a need for a Distribution System Operator (DSO) role to be developed, however our initial thoughts are that until further work is carried out to look at the range of options, it would probably be more efficient to look at a number of parties being involved, which will undoubtedly involve development of current commercial arrangements and the introduction of new arrangements, with all parties being consulted.

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

Not necessarily, but this requires more thought.

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

We believe that this change should form part of a wider review of TNUoS arrangements, in line with our earlier comments and taking account of the other industry work associated with low carbon technologies; Ofgem's commitment along with the Department for Energy and Climate Change (DECC) to look at more flexible ways of managing how we consume and produce electricity and future proofing any changes to accommodate smart meter and smart grid solutions.

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?

We believe this should form part of a wider review and should not be carried out in isolation see above.

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?

We believe this should form part of a wider review and should not be carried out in isolation see above.

In response to your exporting GSPs consultation: <http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Transmission-Network-Use-of-System-Charges/Transmission-Charges-Open-Letters/>

Some brief comments, best of luck bring this to a conclusion.

3.1

The drivers are you licence condition and the increase in embedded generation.

I have separately exchanged emails (24 Sept 2015) with Patrick Hynes on some weaknesses (in my view) of the current TNUoS demand tariffs and how I perceive that the current demand structure mixing triad and NHH consumption provides inconsistent and differing cost signals. In this context a customer trading NHH with PV generation can offset much of their consumption in the late afternoon, so minimise their contribution to TNUoS, whereas on a HH basis the PV will not (typically) be generating at the triad times. Conversely someone who has invested in a CHP boiler may see the opposite effect.

4.1

No. The approach should be applied across all GSPs, otherwise the charge would lead to the export moving to another GSP. The move may be possible by distribution network reconfiguration, or over a longer time, by embedded generators connecting into different parts of the distribution network. Neither of which may be optimal for GB plc

The discussion on GSPs is not simple. Many GSPs have a complex arrangement. I have recently been reviewing Heysham as part of BSC Dispensation. Within this arrangement there is a power station, GSP demand and wind farms. Seeking to fairly attribute costs of assets, and avoided cost of assets is not straightforward.

There is an added complication in that the Scottish GSPs are at a lower voltage than E&W, so they do not have the opportunity to 'average' or 'net' the import/export across more customers.

4.2

The only party that could reasonably have a relationship at a GSP is with is the DNO. The Supplier energy consumption (import and export) in any half hour is only known at the *GSP Group*. The Distributor has the ability to configure and/or re-configure their network to respond to differing demand/generation within their GSP Group. Depending on the local distribution network they can move open points to more evenly balance the import/export. The Distributor is also the party responsible for determining whether they need a GSP connection at that point. In efficiently managing the distribution network they need to consider how their customer load and generation change over time (e.g. heavy industry closing and generation connection).

4.3

Historic actual readings should be used. This can then take account of any practical mitigation (e.g. network reconfiguration) or failure to minimise the charging. Is it reasonable to regard the capacity at a GSP to be considered as a capacity for import and export. How is export at one GSP and import at another GSP all within the same GSP Group considered? Neither GSP may need any reinforcement, but the Distributor could effectively use the transmission network to 'move' energy within their distribution area.

4.4

This sounds simplistic. Is there any logic to this approach? If the peak demand is in the winter and peak export summer does this lead to different costs than when the demand is peak in summer and low in winter. I am thinking of London summer peak due to high cooling load.

4.5

Again sounds very simplistic. There are a number of wind farms connected at the GSP substation to the DNOs network bus bars. How would these be impacted? Would this start to create a price signal not to have a directly connected supply, but to have minimal DNO network connection which minimises the EDCM DUoS cost but avoid this new liability because they are included within the Distributors 'overall' demand/export.

4.7

This seems more logical. It would appear to be a charge for having the capability of exporting. So the Distributor would be incentivised to keep as low as possible by moving export energy over their own network when they could, otherwise it needs to 'spill' onto the transmission network. It almost leads to a volume of energy passing either way in or out of the transmission system incurring a charge.

4.8

This seems too complex. It may result in unexpected and changing cost signals of where to connect certain load/generation.

4.9

Agree with the argument presented. Embedded generation is starting to result in costs which should be reflected to the embedded generators through a price/cost signal. But this price signal must be supported by clear rationale as parties will react to the price signal.

5.1, 5.2, 5.3, 5.4

The ideal model would be that the load/generation is perfectly balanced within a GSP group. The transmission system then becomes a tool to spill/import the 'balancing error' in this idealistic world the transmission system can be significantly reduced in scale/cost. This effect has started to occur with the increase in embedded generation. Scottish Hydro GSP Group is showing the greatest effect by regularly exporting more than the demand within the GSP group. The use of the network should be fairly charge each users group, whether they are demand or generation. In the idealistic approach if the load passing into/out of the GSP connection is minimal then charging framework moves to a fixed charge for the capability existing, rather than a usage charge as a usage charge would be so penal that would encourage its avoidance at all costs.

I would regard balancing as a separate issue from TNUoS charge structure. It could logically lead to DUoS generation charges being structure to be low at high demand times and high at low demand times – the converse of the demand DUoS charges.

Tom Chevalier
Director

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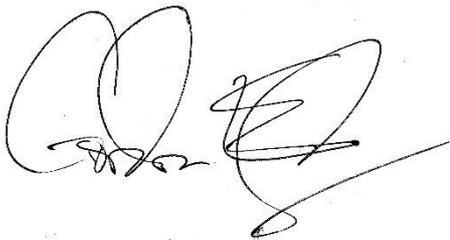
3 November 2015

Dear Andy,

National Grid open letter on potential charging arrangements for exporting grid supply points (GSPs)

Thank you for the opportunity to respond to your open letter, and for showing some flexibility in the timing of our response. You will have seen the joint letter from ourselves, ADE, EnergyUK, REA and Scottish Renewables, and that covers the higher-level issues that we see with your current proposals. We would like to underline that the issue of exporting GSPs needs to be seen in the context of the changing nature of the interaction between the Transmission and Distribution networks. Any proposals emerging from this current consultation will need to cohere with other workstreams in this area, both current, such as the work on flexibility that Ofgem is undertaking, and future, which are, to an extent, inherently unknowable. NG must be careful not to shut down options that may be required in the future. We have a few detailed points that we would like to make, however, and these are set out below as responses to some of the consultation questions. Please get in touch if you have any queries about our response, and I will endeavour to answer them.

Yours Sincerely,



Dr Gordon Edge
Director of Policy – Economics & Regulation

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

RenewableUK welcomes the work completed by National Grid, and appreciates the effort in compiling the information and the time taken to meet the industry at various events. We do, however, feel there is a lack of material evidence to justify a substantial change at this stage. The work presented lacks transparency insofar as it does not attempt to value the impact of other changes at the DNO level, such as: more active management, demand side response providers, and load shifting.

Crucially, it is impossible to comment on the effectiveness of the signal and the options for implementation if we do not know how a DNO would attribute charges to distribution-connected parties. Without knowing this, National Grid could wrongly install an ineffective/unsuitable signal to users, including distributed generators. Therefore we strongly advise that this proposal can only be progressed if progressed in tandem with a relevant associated distribution charging change proposal.

Finally, we do not believe this issue should only be viewed as it stands today, but also account for how the system may develop in the future. Please note our answer to 4.1.

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

(Response also relevant for:

- Q4.2: *Who do you believe is the appropriate party liable for a potential TNUoS local charge?*
- Q4.4: *Do you have any comments on this approach to the potential calculation of a charging base for these options?*
- 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?)*

We did not see any evidence to convince us that Local Circuit Charging would send an effective signal to connecting parties, and therefore cannot support this proposal – please see previous comment about an associated distributed charging change proposal.

We ask NGET to consider whether major demand customers should receive an equivalent signal, and note that demand customers are not subject to a local circuit TNUoS charge. In considering the impact and ability to respond to such signals, we ask that National Grid refers to the work of SmartGrid Forum Workstream 7, which shows increased flexibility and equivalence between demand, generation, and storage users, as well as the flattening of daily profiles. This work shows a need for a more holistic view of network charging in response to a likely significant increase in distributed energy sources; including a harmonisation of transmission and distribution charges, to ensure charges remain relevant and appropriately cost-reflective while avoiding confusing or conflicting market signals.

To highlight our concerns over the increase in charges for distributed generation under the local circuit charge strawman 2, it would be helpful if NG could provide a worked example of the charges attributed to DG connected sites situated in Stornoway once the Western Isles link is complete.

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 refer to changes under the EU Requirements for Generators.

Additionally, we ask any such services from DG to TSO should have contracts compatible (i.e. not mutually exclusive) with services which could be reasonably required by a DSO. Please refer to SmartGrid Forum Workstream 6 for more information.



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**RWE Innogy
Strategy and Regulatory Affairs**

Lewis Elder
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30th October 2015

RWE Innogy response to National Grid informal consultation “Potential Transmission Charging Arrangements at Exporting Grid Supply Points (GSPs)”, issued 6th August 2015.

Dear Mr Corby,

Thank you for the opportunity to respond to this consultation. This response is on behalf of RWE Innogy UK Ltd, RWE Supply & Trading GmbH, RWE Generation UK PLC and RWE Npower Ltd.

We welcome the work completed by National Grid in compiling this consultation and appreciate the time taken to present these plans to the industry at various events over the past two months.

We are, however, unsatisfied with the drivers for this work. There is a lack of information on what is causing GSPs to export. There are a various factors which may play a role in causing the ‘spill’ of power onto the transmission system, such as: demand reduction or load shifting; active management; micro generation; or, the impact of generation holding contractual agreements with National Grid (e.g. BEGAs). Without more information on these factors it is difficult to fully understand what is causing GSPs to export and even more difficult attribute charges to any party in particular (e.g. embedded generators).

We are concerned at the consultation strawman options 1 and 2 which propose to introduce local circuit and substation charges to embedded generation. We would highlight that Demand customers do not and have not been subject to this local charge element so it seems inappropriate to attribute these costs solely on metered embedded generators. Should National Grid continue to investigate this issue, we believe it would be sensible to describe how a potential TEC charge at the GSP Group level could work.

Please find our responses to detailed questions below.

Yours sincerely,

Lewis Elder
RWE Innogy UK

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Drivers for our work

Q1 (3.1) What are your thoughts on the drivers for our work?

The analysis presented in this consultation letter shows that the incidence of export from distribution networks onto the transmission network has been increasing over time. This can be observed regardless of what definition of 'exporting GSP' is applied. There is an apparent change being reported in the way that networks are being utilised and we agree that this warrants a closer look at the phenomena and whether physical network and charging changes are required. It is, as noted in the consultation, a transmission licence obligation to keep the Use of System Charging and Connection Charging methodologies under review at all times and make changes as may be requisite for better achieving the relevant objectives. You have also responded to industry feedback that exporting GSP charging should be looked at.

However, the issue to be resolved as presented is currently too vague to justify any form of change and to start building solutions on. Firstly, the full set of causes for export occurring at GSPs need to be recognised by a review. Secondly there is important evidence missing in the consultation that prevents stakeholders from fully understanding the situation regarding exporting GSPs and their impact on transmission investment. Such evidence must be gathered and presented by NGET not only to provide transparency for stakeholders but, more fundamentally, to be able to establish what changes to charging methodology are actually required.

To provide some detail:

I) The drivers behind spill from DNO to transmission networks need to be understood:

As a first step we need to understand – *who is causing new costs to be incurred?*

There may be a number of reasons for the increase in exports from distribution networks. These could include:

- The growth of embedded generation on DNO networks;
- Increase in contracting for ancillary services by the System Operator from distribution connected assets particularly for STOR products;
- Changes in demand and flow management by DNOs; and
- Reconfiguration of DNO networks through new investments or renewal or removal of existing assets.

Looking at the incidence of spill – there is no explanation in the consultation of how BEGA contracted embedded sites are accounted for in the assessment. We understand from September's TCMF discussions that BEGAs are included in data on the basis that these sites do not pay for local assets. However, in our view this is not relevant as embedded generation is required to pay local connection charges to the DNO and local assets utilised at the GSP are irrelevant. Parties with BEGAs have explicit export rights via their TEC and are subject to TNUoS charges and therefore should be subtracted from the total spill evaluation.

The balance of export and import from distribution networks could also be influenced by a number of additional factors including:

- More active management of DNO network assets by the DNOs themselves (including utilising ancillary services within DNO networks);
- The development and deployment of demand side providers in the capacity market; and
- The introduction of smart meters and associated products in the energy market which results in load shifting.

It is also essential that the incentive properties associated with the transmission charging regime are acknowledged in considering the drivers of exports onto the transmission system.

The extent to which each of these drivers is contributing to any changes in power flows needs to be established in order to develop appropriate charging solutions.

II) Missing data and analysis need to be addressed:

There is a lack of detail in the evidence presented that makes it difficult for respondents to comment on what changes to the current charging methodology are warranted.

The following points are key to answering the question: *what impact does the increase in incidence of export at GSPs have?*

- What is the magnitude of current and forecast export at each GSP? Without this it is impossible to see if there is a material impact on networks from exporting GSPs.
(The only information currently provided is that at most GSPs net export is smaller than 25MW – this is not adequate detail. If exact figures per GSP are not available a range should be provided with some comment on the distribution).
- What reinforcement work is required based on the current export figures?
- What reinforcement work is required based on forecast export from GSPs?
- There is no explanation of what cost impact the spill has currently nor is there a forecast for the future. This information needs to be made available.

There are two further points from us regarding this section of the consultation:

We request that NGET consider the merits of a de minimus threshold:

NGET should consider the merits of a de minimus threshold for exports. The administrative cost of passing through charges to embedded customer's needs to be evaluated by both NGET and DNOs.

Feedback on definition of exporting GSP

Embedded generation predominantly serves to offset demand and only the spill is the issue. Therefore, we support NGET's general approach of looking at net exports when thinking about which GSPs charges may need to be targeted at.

You present various options for which definition of 'exporting GSP' to be used for identifying GSPs that could be having an impact on network reinforcement need¹. We agree that using the "max export > max import" criteria is logical. This will identify "those GSPs which have a higher maximum power export than their maximum power import during that financial year". It fits well with the TNUoS charging methodology, the difference in max half hour export and max half hour import can be used to assess system spill. This measure could also enable the DNO to actively manage the flows based on the price signal new charging arrangements could provide.

We suggest that NGET also investigate GSP Groups as a basis for assessing whether a net export is occurring. GSP Groups that are used for the basis of settlement charging and therefore assigning the equivalent of a TEC to a DNO area could form an alternative potential basis of charging DNOs.

Local TNUoS charging options

Q2 (4.1) Do you agree that any local TNUoS charging option should be limited to those GSPs which export power onto the transmission network?

To summarise your rationale for proposing local TNUoS charges: these options consider that an exporting GSP behaves in a similar manner to a generator exporting power onto the transmission system. Local charging options would reflect the incremental cost of an exporting GSP on local transmission infrastructure.

We disagree with the justification for applying local charges for exporting GSPs. You report that many GSPs are already exporting and there is no demonstration that this is demanding new investment in existing local assets. Local assets can serve both export and import functions- electricity can flow in either direction. Although no evidence is provided in the consultation it seems more likely that the impact of increased export from GSPs would be on the wider transmission network that may not have sufficient spare capacity to take these additional net export flows.

We also disagree with the principle of differentiating between 'exporting' and 'importing' GSPs: we consider that all GSPs should be treated in the same manner for any charges.

¹ (p4 of consultation paper sets out different definitions)

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

As set out above, we disagree with local TNUoS charges but if charges are introduced for net exporting GSPs these should be targeted at the DNOs. The DNO is the only party that has visibility and control of net flows at the GSP and has the contractual relationship with all parties contributing.

Q3 (4.3) What are your views on using historic metering data to determine the charging base?

Demand prediction causes under or over revenue recovery risk for National Grid. The utilisation of an equivalent of TEC as a charging base for DNO's mitigates this risk as it would give National Grid a more stable charging base, in comparison to using demand prediction. Under this arrangement, we envisage that the DNOs would indicate the TEC they require based on their anticipated max export for the year and would then have an incentive to managing capacity within this limit. We therefore consider that historic metering data should not be considered in relation to this proposal.

Q4 (4.4) Do you have any comments on this approach to the potential calculation of a charging base for these options?

We support the approach taken that net export at the DNO-Transmission boundary is the basis for any exporting GSP charges being considered. We have also explained under Q3.1 that we agree that those GSPs where Max export > Max import should be considered in the charging base. We also explained that the contribution of BEGA sites should be discounted from this assessment and that the application of a de minimus threshold would be economically efficient.

We suggest assigning a TEC equivalent for DNOs could work for a charging base since TEC feeds into the load flow model. The physical connection of a DNO to the transmission network is analogous to that of a power station connection. Contractually assigning a value of TEC to GSPs or GSP Groups can also be achieved in a relatively straightforward way by modifying existing DNO transmission connection contracts.

As previously set out, net export at GSP Group level should also be researched by NGET as an option because a GSP Group can be seen as analogous to a trading BMU. Under this approach each GSP would have CEC while the TEC would be defined at the GSP Group level.

The DNO would be responsible for identifying how much TEC it needs based on its forecast of the balance of import and export that its customers demand. The DNO is then the party that needs to target charges appropriately to those parties on its own networks. This charge would then need to be apportioned to the parties connected to the DNOs distribution network via DUoS charges in accordance with its charging methodology – we would not expect the DNO to capture a financial return in fulfilling this role.

At this early stage, DNOs need to look at how both demand and generation contribution to GSP flows can be measured and charged for. It is essential that ahead of the implementation of any modified transmission charging rules DNOs have agreed a uniform methodology amongst themselves via DCUSA. There has been precedent of this not been given due consideration (e.g. CMP192) and this should be avoided.

Q5 (4.5) Do you have any comments on our proposed approach to transformers at shared exporting GSPs?

This is reported as a very rare situation – we would like to understand whether the impact on the residual is significant, what are the financial implications on the residual charge with the single example where this is happening? The solution proposed is complicated and appears to lead to volatile annual charges for the parties connecting to the GSP.

Q6 (4.6) Do you have any comments on the potential change to the MITS node definition?

We disagree with the proposal to change the MITs node definition.

Q7 (4.7) What are your views of potential local TNUoS charging option 1?

We disagree with Local TNUoS charge for reasons set out in Q.4.1.

We cannot comment on the specific option due to an absence of sufficient information on the drivers for export or the impact on local substation investment. We cannot assess the impact of this proposal because the information provided is insufficient.

Q8 (4.8) What are your views of potential TNUoS charging option 2?

We disagree with Local TNUoS charge for reasons set out in Q.4.1.

We cannot comment on the specific option due to an absence of sufficient information on the drivers for export or the impact on local substation and local circuit investment. We cannot assess the impact of this proposal because the information provided is insufficient.

Q9 (4.9) Do you have any comments on potential options for a recovery mechanism for any local TNUoS charge passed through to a DNO?

This is a matter for the DNOs and would be subject to a separate DUoS charging methodology review. As stated previously the impact of different drivers for export and the consequences of export at GSPs must be quantified before charges and charging options are considered. However, we would expect that any such costs would be directly passed through so as not to incur additional costs on consumers.

Longer term commercial arrangements

Q10 (5.1) 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?

No, we consider that parties who influence the costs of the system operator should all be liable for the costs of balancing the system. This is true of users and network owners.

Q11 (5.2) 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?

No response other than that all parties, specifically generation and demand, should be treated equitably.

Q12 (5.3) Who do you believe could be an efficient party to assist in the procurement of balancing services from distributed generation?

In order to understand the cost effectiveness of such arrangements we would find it helpful to understand what processes/criteria (e.g. technical requirements, compliance process, bilateral contracts, instruction process, metering, reconciliation etc.) would be required to acquire balancing services from distributed generation. Until we know this, we are unable to respond as to who should assist in the procurement of these services.

Q13 (5.4) Do you believe our thoughts should be limited to models considering an aggregator at this time?

No, see Q12 above. Embedded generation (whether aggregated or not) has potential to provide solutions to some of the issues raised in this informal consultation but would require an open and transparent regime in place with appropriate incentives.

Q14 (5.5) Do you believe wider TNUoS arrangements should be reviewed to more appropriately account for distributed generation and responsive demand?

No. With the regulatory / ownership separation of obligations at the transmission / distribution boundary, the scope of TNUoS should end at the transmission – distribution / directly connected User boundary and any power transfers at these boundaries treated on a net basis. That said, in the event that National Grid is instructing distributed gen-

eration to provide services, arrangements should be in place to ensure that National Grid recompense the DNO, to ensure other distribution system users are not financially disadvantaged.

Q15 (5.6) Do you believe the potential local TNUoS charging options (laid out in section 4) help move arrangements towards those required in the future?

No, the proposals in Section 4 are introducing local charges, which seem inappropriate given that the consultation has not justified that impacts are caused for local assets. The proposal to introduce a local TNUoS charge would suggest that the defect this proposal aims to address is primarily an issue related to the local transmission assets as opposed to the wider transmission infrastructure. It would be helpful for National Grid to confirm that this is the case, since local charges do not give any locational signal and do not include the cost of using the wider transmission system.

In any event, most local GSP assets are needed for power import and therefore to apply a local charge based on the same assets being used to export power would seem to be an arbitrary arrangement.

Q16 (5.7) Do you believe we should be considering any other changes to transmission arrangements to facilitate access to services from distributed generation and responsive demand?

National Grid should also consider the EU Requirements for Generators (RfG) as applied to GB to enable market access for embedded entities in relation to this consultation.

Thank you, once again for the opportunity to comment on this consultation.

Please feel free to contact us should you wish to discuss or clarify any of the responses in this paper.

Dave Corby
Grid Access and Charging Development
National Grid
Warwick Technology Park
Gallows Hill
Warwick
CV34 6DA

31 October 2015

Dear Dave,

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

Thank you for the opportunity to respond to your informal consultation paper on potential transmission charging arrangements at exporting Grid Supply Points (GSPs).

ScottishPower acknowledges that transmission charging methodologies should adapt to reflect the changing nature of the transmission network and increases in the deployment of low carbon generation on distribution networks.

Charging arrangements should likewise take account of the changing nature of distribution networks with the increasing deployment of smart-grid technologies and the increasing role of the Distribution Network Operators (DNOs) in managing flow within their networks and through the GSP interfaces with the transmission system.

As an increasing proportion of investment in generation capacity has been and will continue to be made on distribution networks, it is essential that developers have clarity and certainty over future charges in order to facilitate efficient economic investment decisions.

Our responses to the specific questions in the informal consultation are contained in the attached annexe.

Yours sincerely,

James Anderson
Commercial & Trading Arrangements Manager

Drivers for our work

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

ScottishPower acknowledges that transmission charging methodologies should adapt to reflect the changing nature of the transmission network and increases in the deployment of low carbon generation on distribution networks. This is resulting in distribution networks and their associated GSPs playing a non-traditional role as collector networks for embedded generation in addition to meeting the traditional electricity demand needs of customers.

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?

Yes. ScottishPower supports the underlying assumption that the primary role of a GSP is to act as the interface between customer demand on a distribution networks and the bulk supply of power on the transmission network. However, where investment at a GSP is being driven by an increase in embedded generation and not by the demand connected then we believe that is appropriate for a this cost to be reflected at that exporting GSP.

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

At present settlement systems only manage the relationship with suppliers at a GSP Group level and not at the level of individual GSPs. It would therefore require a major revision of the existing settlement systems to apply a TNUoS charge at an exporting GSP directly to suppliers. It is difficult to foresee how any potential benefit from improved signalling of infrastructure investment costs would be sufficient to justify the potentially significant cost of such a change to settlement systems.

The GSP is the interface point between the transmission and distribution system and the contractual relationships around its construction and operation are between National Grid and the DNO. National Grid in most cases does not have a contractual relationship with the embedded generator unless the generator has entered into a bilateral agreement (BEGA or BELLA). The administrative burden of creating contractual relationships with all distributed generators would likely outweigh any potential benefits of reflecting costs upon these generators.

As the DNO is the only party who has the ability to manage export power flows from its network through the GSP it would be appropriate for the liability for any potential local TNUoS charge to fall on the DNO. Depending on the arrangements for recovery of such charges by the DNO, placing this liability on the DNO could act as an incentive on the DNO to manage power flows at a GSP to minimise export flows and hence the requirement for potential future investment in increased export capacity at the GSP.

Reflecting the costs of exporting GSPs should be used as an opportunity to signal the benefits of moving towards a DSO model.

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

Although the use of historic data is intrinsically less cost reflective than current year data, ex-ante charges provide certainty and allow parties to make better economic

decisions than ex-post charges. Much of the embedded generation may be intermittent in nature and therefore it would be difficult to forecast its potential output at periods corresponding to various levels of demand in order to derive a forecast net GSP export. In addition, due to the nature of distribution networks, it may be difficult to model which GSPs on a DNO's network could be impacted by connection of further embedded generation.

On this basis, ScottishPower would support the use of historic metering data in determining whether a GSP should enter the charging base.

However, we have concerns that use of a single year's historic data could result in a GSP being classified as Exporting due to unique or unusual circumstances on the associated distribution or transmission networks e.g. circuit outages resulting in atypical flows. It may be necessary to examine the maximum import and export over a number of years using a methodology similar to the Annualised Load Factor methodology in TNUoS to remove anomalies. Alternatively, a mechanism to allow DNOs to appeal the classification of a GSP as Exporting could be adopted.

Increasingly, parties are looking for greater certainty over future charges (see CMP244, CMP250 and DCP178) and any methodology should be consistent with this aspiration.

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

The TNUoS charging methodology is a forward-looking, incremental methodology which considers the impact of an additional 1MW of generation or demand on transmission investment.

Under the proposed charging methodology there is a risk that increased investment is indicated at a GSP while there is still significant excess capacity available. Please see the attached example (Appendix1).

It may be necessary to consider the extent to which conventional and intermittent generation share export capacity at a GSP in order to provide a cost-reflective local substation charge. Peaking or conventional generation may "depress" maximum import meter readings leading to maximum export exceeding import at a value well below the physical export capacity of the GSP i.e. indicating that incremental embedded generation may trigger GSP reinforcement much sooner than would actually be the case

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

We agree in principle with the aim of reflecting the costs associated with "infrastructure transformers" on users at exporting GSPs. However, the indicative local Transformer Tariffs in table 4.2 are significantly higher than the Onshore Local Substation Tariffs in Table 1.6 of the current Statement of TNUoS Charges. This would appear to imply that power flows onto the transmission system from embedded generation would be charged at a higher rate (£/kW) for exporting onto the transmission system than a directly connected generator.

We would seek clarification on how the potential re-classification of transformer assets would be accommodated within the proposed changes. At present, embedded generators can be asked to make a "one-off payment" towards the cost of a transformer which is considered a connection asset. If this proposal results in the

transformer being re-classified as an infrastructure asset would the embedded generator be reimbursed for its previous payments?

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

We have concerns that changing the definition of a MITS node could have charging implications for directly-connected generation thereby exposing them to an unexpected local substation/circuit charge. It would be helpful to have clear information which nodes would be impacted immediately by such a change of definition and which would potentially change in future e.gg through the publication of an indicative MITS Map.

The potential “flipping” of GSPs from export to import from year to year could result in nodes changing status from MITS to non-MITS resulting in increased uncertainty for directly-connected generators whether they would face a local circuit charge.

Any change to the definition of a MITS node should be considered carefully to ensure that there are no unexpected consequences beyond the charging methodology.

Q4.7 What are your views of potential local TNUoS charging option1?

We believe that potential charging option 1 (introduction of a local substation TNUoS charge) for exporting GSPs could be an appropriate way forward. However, the charges would be applicable at lower connection voltages in Scotland than in England and Wales due the differences in the definition of the transmission/distribution boundary. If the data is available, it would be interesting to determine how many 275kV substations in Scotland would be classified as “Exporting” under the definition within this proposal and whether the proportion would be more similar to that illustrated in England and Wales.

Q4.8 What are your views of potential local TNUoS charging option2?

Where investment at a GSP and the associated circuits between it and the Main Interconnected Transmission System is being driven by export flows it would seem appropriate for the charging methodology to be aligned with that for directly connected generation and a local circuit charge should be applied. However, consideration would be required as to the proportion of the circuit cost to be reflected on the exporting GSP.

A local circuit provided for one or more directly-connected generators is solely for their use; a local circuit at an exporting GSP would only trigger a charge because for a limited period (perhaps as little as one settlement period per year) the maximum export exceeded the maximum import. Consideration would therefore have to be given as to the split of any charge between the export and import flows.

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

ScottishPower believes that if transmission charging arrangements for Exporting GSPs are progressed then the corresponding distribution charging proposal detailing how DNOs would pass charges on to connected parties must be progressed in parallel. This would enable parties to fully assess the potential impact of the changes.

Any TNUoS charge applied to an exporting GSP should provide a signal to the relevant Distribution System Operator (DSO) to manage the flows at the GSP. This could

involve active power management or investment in infrastructure on the distribution network to manage the relevant exports. The signal provided would have limited effect on the DSO should it simply be able to pass-through the TNUoS cost to its customers.

However, should some form of pass-through of the exporting GSP TNUoS charge be envisaged it should follow the principles of cost reflectivity and where this cannot be clearly identified the costs should be socialised. In practice it may prove difficult to determine responsibility for exporting power flows at GSPs as these could be triggered by DSO system management or outage decisions in addition to generator operating decisions. Any pass-through of costs should be accompanied by an incentive upon the DSO to minimise any charge incurred.

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?

We consider that the existing methodology of charging BSUoS on the net transfers onto the transmission system remains appropriate.

It is not clear which particular costs National Grid have identified as being driven by embedded generation. Where a GSP is identified as exporting it could be argued that there may be some potential contribution to any constraint costs in the local area. However, it may be difficult to identify to what extent embedded generation benefits from the existence of a stable transmission system and should contribute towards the cost of its provision or whether embedded generation reduces the requirement for such services from the transmission system by providing system management services directly to the distribution network and thus reduces the cost to the transmission system operator.

BSUoS is charged to parties across the full year based upon their metered output. However, the potential charging mechanism being discussed is based upon the maximum export as measured in a single settlement period exceeding the maximum import during the preceding year. Therefore it is not clear how BSUoS could be applied at Exporting GSPs. It would be inappropriate to apply a BSUoS charge for the full year based upon power flows in the previous year which could have been triggered by atypical circumstances in a single settlement period.

A further consideration is the possibility that applying a BSUoS charge to parties who provide services to the System Operator could either act as a disincentive to those parties providing the service or result in the additional BSUoS cost being reflected back to the System Operator in the prices at which the services are offered.

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?

It is not clear how such further commercial arrangements with distributed generation and responsive demand could be introduced without a clearer understanding of the respective future roles of Transmission and Distribution System Operators and the interface between them.

If DSOs are incentivised appropriately to manage power flows at the interface with the transmission system then it may not be necessary for the TSO to develop contractual relationships with embedded parties.

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

At present there is an identified role for parties to aggregate balancing services from smaller embedded parties and to offer these to the TSO and we would envisage this role being developed further.

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

Yes.

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

This would not appear to be an appropriate time to consider changes to the wider TNUoS arrangements in GB as we are awaiting guidance from the European Commission on tariff harmonisation and any substantive change could be contrary to the direction of travel in Europe.

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?

We believe that option (a) in section 4 could help move charging arrangements towards those required in the future if developed in full consultation with market participants.

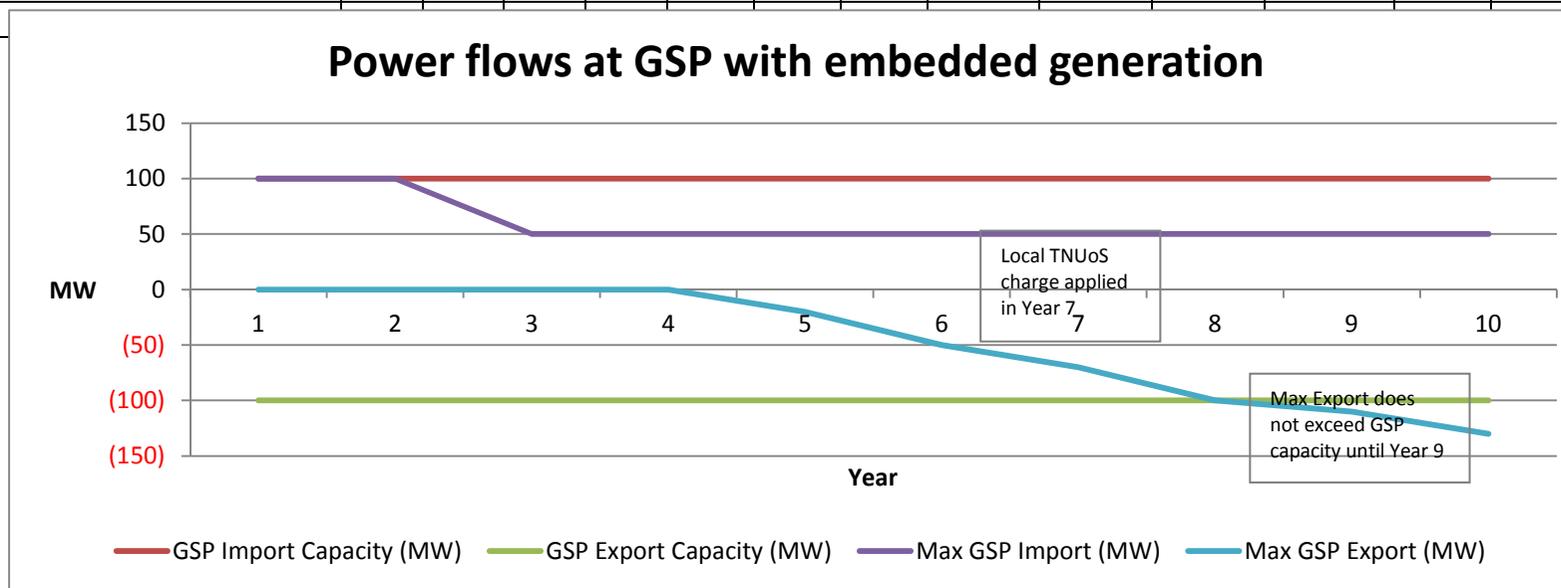
Q5.7 Do you believe we should be considering any other changes to transmission arrangements to facilitate access to services from distributed generation and responsive demand?

We do not believe that any further changes should be considered at this stage.

Appendix 1

Triggers for applying a Local TNUoS Charge compared with triggers for reinforcement and an Exporting GSP															
Year	1	2	3	4	5	6	7	8	9	10					
Peak Demand (MW)	100	100	100	100	100	100	100	100	100	100	100				
Min Demand (MW)	50	50	50	50	50	50	50	50	50	50	50				
GSP Capacity (MW)	100	100	100	100	100	100	100	100	100	100	100	Note 1			
Peaking Plant (MW)	0	0	50	50	50	50	50	50	50	50	50	Note 2			
Intermittent Plant (MW)	0	0	0	40	70	100	120	150	160	160	180	Note 3			
Max GSP Import (MW)	100	100	50	50	50	50	50	50	50	50	50	Peak Demand - Peaking Plant output			
Max GSP Export (MW)	0	0	0	0	(20)	(50)	(70)	(100)	(110)	(110)	(130)	Min Demand - Intermittent Plant output			
Max GSP Export exceeds Max Import	No	No	No	No	No	No	Yes	Yes	Yes	Yes	Yes				
Note 1	assumes GSP capacity built to accommodate Maximum Demand and that GSP has equal import and export capacity														
Note 2	assumes Peaking Plant will operate to mitigate Peak Demand but has negligible output at other periods														
Note 3	assumes Intermittent Plant will make a negligible contribution at times of Peak Demand but may reach 100% output at times of low or even minimum demand														
In the above example, the GSP would be deemed to be "Net Exporting" in Year 7, when the Max GSP Export (120MW of Intermittent output at the time of lowest demand 50MW) exceeds the Max GSP Import (100MW demand reduced by 50MW of Peaking Plant output)															

	However the maximum GSP export would not exceed the export capacity of the GSP (100MW) until Year 9 when the Net Export of 110MW (160MW of Intermittent output at the time of minimum demand 50MW) exceeded this physical capacity.		
	It would only be in Year 9 and not year 7 that incremental investment in the GSP would be required to accommodate the additional export flows. i.e. a further 50MW of embedded generation could be connected to the GSP before further investment was required.		
	Applying a local TNUoS charge to the DNO in Year 7 could signal a requirement for reinforcement in the GSP too far in advance of the economically efficient point for investment		
	This appears to be due to the effect of Peaking (or Baseload) embedded generation suppressing the Maximum Import and therefore it may be necessary to take account of "sharing" of the GSP Export capacity between Conventional and Intermittent plant in order to reflect this. This would be similar to the Peak and Year Round structures within the wider locational TNUoS tariff methodology.		



Andy Wainwright
National Grid House
Warwick Technology Park,
Warwick
CV34 6DA

21 October 2015

Dear Andy,

National Grid open letter on potential charging arrangements for exporting grid supply points (GSPs)

Scottish Renewables is the voice of the renewable energy industry in Scotland representing more than 320 organisations including developers, community groups and supply chain companies actively working across wind, solar, hydro, marine, biomass and low carbon heat technologies.

We have been closely involved in the recent work to consider grandfathering arrangements for embedded generators and the subsequent exercise to review the charging arrangements for exporting GSPs. We appreciate the time taken to meet with industry at various events and meetings and welcome the opportunity to respond to the current open letter, in advance of any modification proposals being brought to the Connection and Use of System Code Panel (CUSC panel).

We have worked with The Association for Decentralised Energy, Energy UK, Renewable Energy Association, and Renewable UK to develop a common and united view on the proposed charging arrangements. The attached response builds on these high level points and offers Scottish Renewables additional views in response to the consultation questions.

We would be happy to contribute to any additional work arising from this consultation.

Kind regards,

Michael Rieley
Senior Policy Manager: Grid & Markets

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Consultation Questions

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

While we are supportive of the principle of developing charging arrangements for exporting GSPs where there is a cost impact on the network, there is some concern that the proposal in its current form does not provide sufficient information

Overall, we consider that any proposed changes must provide a solution that will result in a fairer and more cost reflective charging regime.

It is our view that a successful implementation of charging arrangements on exporting GSPs will depend greatly on a number of factors which are not yet addressed in any detail. These include:

- The proposal as set out does not provide sufficient information about how the change would be implemented and about how exporting GSPs impact transmission network costs.
- Without knowledge of how DNO's would pass charges on to connected parties it is difficult to accurately assess the options presented. This runs the risk of unintended consequences, including counter-productive charging signals. Therefore any proposals to implement a charging methodology for exporting GSPs under the CUSC should be carried out in parallel with a Distribution Connection and Use of System Agreement (DCUSA) modification. It will also be important that as much as possible the charge is forecastable for each class of user on a year by year as well as on a medium-term basis.
- The work presented does not attempt to value the impact of other changes at the DNO level, such as: more active management, demand side response providers, and load shifting. In particular it is vital that any arrangements do not create an unnecessary barrier to the development of DNO's taking on the role of DSO's (this is in line with recent statements from Ofgem1)
- We see a significant risk that a charging arrangement that does not integrate these longer-term aims of a more flexible and responsive system into account could inhibit market participants' ability to react to short-term signals to prevent the need for additional infrastructure investment, raising the overall costs for consumers.
- While we support the principle that exporting GSPs should be charged in the same manner as a transmission-connected generator, changes to the MITS node definition would have consequences that go beyond charging arrangements. Therefore, the full implications of such a change should be considered carefully with industry to ensure they are implemented appropriately.

We would encourage National Grid to further consider these points before any changes are proposed

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

We did not see any evidence to convince us that Local Circuit Charging would send an effective signal to connecting parties, and therefore cannot support this proposal – please see previous comment about an associated distributed charging change proposal.

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

It is our view that DNOs would be the most appropriate party and that this should be used as an opportunity to move towards a DSO model.

In addition, it is vital that such models should enable relevant price signals to set the right incentives for demand side solutions.

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

There is some concern that historic data will not provide an appropriate signal for marginal GSPs which are not yet exporting. We propose that, if historic data is to be used, that National Grid should publish exporting GSP forecasts to indicate which GSPs are currently exporting and which are expected to begin exporting within the following five years

It is important that the charging base is consistent with the outcome of the following CUSC modification proposals

- CMP244 ‘Set final Transmission Network Use of System (TNUoS) tariffs at least 15 months ahead of each charging year’
- CMP250 ‘Stabilising Balancing Service Use of System (BSUoS) with at least a twelve month notice period’

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

The actual impacts of exporting GSPs on local assets are not explained in the consultation making it difficult to respond.

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

The proposed solution appears to lead to volatile charges for parties connecting to a GSP which is undesirable.

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

There is significant concern within industry that these changes are being proposed with the sole purpose of facilitating the charging arrangements for exporting GSPs. Such changes to the MITS node definition would have consequences that go beyond charging arrangements and would require justification taking account of such implications

In particular, we have concerns that changing the definition of a MITS node could have charging implications for directly-connected generation thereby exposing them to an

unexpected local substation/circuit charge. It would be helpful to have clear information which nodes would be impacted immediately by such a change of definition and which would potentially change in future e.gg through the publication of an indicative MITS Map.

The potential “flipping” of GSPs from export to import from year to year could result in nodes changing status from MITS to non-MITS resulting in increased uncertainty for directly-connected generators whether they would face a local circuit charge.

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

We would encourage National Grid to undertake further analysis to provide industry with the following information in order to make a better informed response on the options put forward (see below).

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

We would encourage National Grid to undertake further analysis to provide industry with the following information in order to make a better informed response on the options put forward

- The proposal as set out does not provide sufficient information about how the change would be implemented and about how exporting GSPs impact transmission network costs.
- Without knowledge of how DNO’s would pass charges on to connected parties it is difficult to accurately assess the options presented. This runs the risk of unintended consequences, including counter-productive charging signals. Therefore any proposals to implement a charging methodology for exporting GSPs under the CUSC should be carried out in parallel with a Distribution Connection and Use of System Agreement (DCUSA) modification. It will also be important that as much as possible the charge is forecastable for each class of user on a year by year as well as on a medium-term basis.
- The work presented does not attempt to value the impact of other changes at the DNO level, such as: more active management, demand side response providers, and load shifting. In particular it is vital that any arrangements do not create an unnecessary barrier to the development of DNO’s taking on the role of DSO’s (this is in line with recent statements from Ofgem1)
- We see a significant risk that a charging arrangement that does not integrate these longer-term aims of a more flexible and responsive system into account could inhibit market participants’ ability to react to short-term signals to prevent the need for additional infrastructure investment, raising the overall costs for consumers.
- While we support the principle that exporting GSPs should be charged in the same manner as a transmission-connected generator, changes to the MITS node definition would have consequences that go beyond charging arrangements. Therefore, the full implications of such a change should be considered carefully with industry to ensure they are implemented appropriately.

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

This is a matter for DNOs to respond to, however we would expect this to be a direct pass-through item so that customers do not incur additional costs.

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?

We agree that distributed generation could do more, but it is perhaps more realistic to assume this would be co-ordinated by a DSO role.

It is important that this work is aligned with emerging EU legislation in particular – ‘Requirements for Generators’ and the Demand Connections Code. These laws will effectively set a legal requirement on generation and demand customers to provide certain services to the system operator.

The Demand Connection Code in particular focusses on industrial loads and DSO’s, will set out the requirements which will apply to the demand side of the power system and will introduce DSR measures on a non-mandatory basis.

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?

No. Embedded generation (whether aggregated or not) has potential to provide solutions to some of the issues raised if an open and transparent regime is put in place with appropriate incentives.

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?

The vast majority of ‘exporting’ GSPs are located in Scotland where the transmission network begins at 132kv – We would therefore encourage National Grid to consider if the reclassification of 132kV could offer a solution to the issue of exporting GSPs



FAO: Dave Corby,
National Grid

Reference Number: N/A

Email: dave.corby@nationalgrid.com

30 October 2015

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

Dear Dave,

SmartestEnergy welcomes the opportunity to respond to NGT's Informal Consultation Paper on Potential Transmission Charging Arrangements at Exporting Grid Supply Points (GSPs)

SmartestEnergy is an aggregator of embedded generation and a supplier in the electricity retail market serving large corporate and group organisations.

Please note that our response is not confidential.

Overview

We are largely supportive of the proposals in the Informal Consultation Paper relating to exporting GSPs but not necessarily in relation to further developments. We have always said that NGT should only be concerned with physical flows onto the transmission system, not the market arrangements that overlay the system and that charging should relate to the flows on the respective network generation is connected to.

The concept of "exporting GSPs" is a physical issue. It is, therefore, not appropriate to attempt to resolve it through notional supplier groupings but through charging the DNOs who will then pass the charges on through their own methodology.

Answers to specific questions.

We answer the specific questions in the document below:

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

We understand that there are GSPs which export at peak and that the level of embedded generation is set to increase. As exporting GSPs create a need for



smarter brighter better

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investment on the transmission network, we agree that it is reasonable for these costs to be recovered from parties other than those who are currently deemed to be transmission network users. We also agree with the document when it states that the natural home for these charges is the DNOs as all network companies have licence obligations to ensure efficient system development and they should be in a position to respond to the charging signal. This also makes sense because, as the document points out, the DNO is the party that National Grid has a contractual relationship with at the GSP and also because the DNO is the party with responsibility for co-ordinating net power flows at the GSP.

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

Yes we agree that any local TNUoS charging option should be limited to those GSPs which export power onto the transmission network. We are slightly concerned by the implication of the following wording: "We have not considered extending these arrangements to importing GSPs *at this time*." [Our italics]. We do not believe that this would be appropriate at any time; importing GSPs are the normal state of affairs and all other charging (Transmission/Distribution) is already structured around this.

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

DNOs are the appropriate party liable for a potential TNUoS local charge. Please see our answer to Q3.1. As the document states, it would be inappropriate for suppliers to be liable parties as there is no contractual arrangement between NGT and Suppliers at this level and, more importantly, suppliers are not in a position to respond to a TNUoS signal or roll in other commercial decisions they make, as DNOs are.

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

We agree with NGT that only those GSPs which would be reinforced on an incremental basis should be liable for the charge, although we are not sure that the methodology of taking GSPs with a higher maximum export than their maximum is the right one just to be consistent with the current methodology. Given that this is to do with investment on the network it would be more logical to apply to those GSPs which export at peak.

We have no particular strong views on the use of historic metering data to determine the charging base if it can be shown that there would not be much of a deviation from reality if charges are calculated and published at a year ahead stage. However, if the lead time for this process becomes too long we would question whether it is accurate enough. Using a forecast may be more appropriate as it should tie in with NGT's plans to upgrade the network. We are, however, not really in a position to judge whether the risk of forecasts being wrong outweighs the inaccuracy of the time-lag of an ex-post approach.



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

It would appear that the desire to use the difference between a GSP's maximum export and its maximum import is to ensure stability in the approach; we do not believe that there could be too much flipping back and forth year on year. Basing the charges on peak export would be fairer, more consistent with the justification for the charge and bring in more GSPs.

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

No

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

No

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

We agree that it is logical that an exporting GSP should be charged for local sub-station charges as it is not offsetting the need for transmission investment at that GSP.

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

We believe it is less appropriate to charge local circuit charges to embedded export as these seem to us to be more of a charge which comes about by the existence and arrangement of generators in the location. The point of connection at the GSP (substation) is where the net embedded generation is delivering and is an immovable point around which the Transmission local network is configured.

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

We agree that the costs should be borne by the party which can respond to the charging signal. In the first instance, this is the DNO. Whilst we would ordinarily tend to agree that the socialisation of an exporting GSP charge across an entire charging base would be inappropriate it is not for this or any future NGT consultation to establish how DNOs would pass the charges on. It is up to the DNOs to consider this in the context of their system configuration, charging regime, ability to respond, commercial decisions etc. We would also expect Ofgem to show an interest in to whether DNOs are responding to the price signal rather than merely passing it on, which may be inappropriate as a sudden decrease in demand connection could



cause a flip but it would be unfair to place the charge on the generation that was built at a time when there was sufficient local demand.

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?

In the current network ownership and contractual structure we believe that the current arrangements are appropriate. As National Grid is dealing with distribution networks and suppliers on a net basis it is not in a position to charge individual parties for any costs deemed attributable to BSUoS. If National Grid is using the balancing services of embedded generators it is doing so because it is cost effective for the GB system as a whole. It is not right to say that these generators are using the system any more than they are with their basic contracted energy, in other words, arguments relating to embedded benefits related to contracted energy apply equally to balancing energy.

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?

At this stage we believe further commercial arrangements are inappropriate.

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

A supplier or third party aggregator.

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

Yes. It is not appropriate for National Grid to be contracting direct at this stage.

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

No. It has not been shown that embedded generation is "accessing" the transmission network. It is offsetting local demand up to the point that a GSP starts to export.

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?

No. Please see answer to Q5.7





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?

As previously stated, National Grid should restrict itself to dealing with DNOs on a net basis. We accept that the model of transmission for generation and distribution for demand is becoming increasingly out-dated. Unfortunately, it is cemented in the ownership and contractual arrangements. In the longer term, we can foresee the need for a single system operator across transmission and distribution. This could work in a similar way to the way in which Scotland has been assimilated into the GB arrangements with NGT as System operator and DNOs as system owners. This would enable a network wide charging regime which would solve all anomalies with embedded generation etc. However, this would require fundamental industry restructuring.

As an interim step we can see some merit in NGT increasing their remit to include 132kV connections. There, must not be, however, any double charging with DNOs' charging methodologies. National Grid would essentially have to come to an arrangement to pay the DNOs.

Should you require further clarification on this matter, please do not hesitate to contact me.

Yours sincerely,

Colin Prestwich

smartestenergy

Head of Regulatory Affairs
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**Marubeni
Group**

Potential Transmission Charging Arrangements for Exporting GSPs - Informal Consultation

Further to the informal consultation issued on 6th August 2015, please find below the response from SP Energy Networks on the issues raised in relation to Potential Transmission Charging Arrangements for Exporting GSPs.

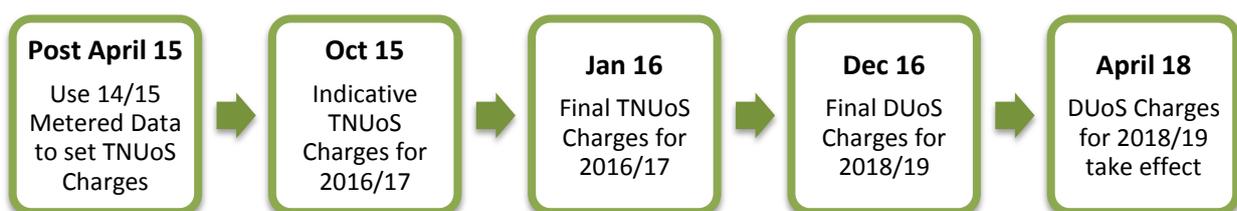
Introduction

Whilst we agree that one of the drivers for GSPs exporting onto the transmission network is the increase in embedded generation, a number of other factors are becoming increasingly relevant. A GSP is not acting in the same way, nor does it have the same rights, as a generator connected directly to the transmission system (with an agreed TEC). A GSP can become an exporting GSP for a number of reasons (e.g. demand side response and load shifting). This will be of particular importance when developing cost signals and ways to pass on relevant costs to a DNO's customer base.

The continuing development of flexible networks will impact on demand / export levels at particular locations and this proposal could introduce volatile charges that will be difficult to forecast in a cost reflective manner.

We would also like to further understand the following:

- The network areas of Scotland are most impacted by these proposals. How have the considerably lower rating of GSPs in Scotland compared with those in England and Wales been considered? The same amount of generation connecting at a GSP in Scotland would be subject to additional charges whereas it wouldn't be in England and Wales, leading to potential discrimination between customers connected to the distribution network in Scotland and those connected in England and Wales.
- Therefore, is it appropriate to target individual GSPs rather than a GSP Group? The reason why a GSP exports should be considered.
- How would the proposed charges impact on the current "Small Generator Discount" given to those small generators connected at 132kV?
- In circumstances where an exporting GSP has large generators connected who already have price signals via charges from NGET and smaller generators who do not – how the charges could be split between such customers will need to be considered.
- Legacy exporting GSPs where embedded generation is connected in areas with very little demand and provide system services such as voltage support. Without this generation wider reinforcement would be required. How would this be treated?
- Alignment with DUoS charge setting. The timeline for setting charges will impact on both the cost signals and recovery, especially in view of delays in pass through of costs and the 15 months' notice period required for setting DUoS charges. In summary based on current arrangements:



TNUoS charges calculated for 2016/17 (based on 14/15 data) may not be applied to DUoS customers until 2018/19 (or later), by which time the GSP may no longer be exporting

and/or the targeted customer may no longer be connected. (CMP 244¹ may also impact on the timeline to reflect TNUoS charges for exporting GSPs in DUoS charges).

Specifically on some of the points raised:

New GSP Connections

Within the SP Distribution and SP Manweb network areas, 100% of the new GSPs recently connected were developed for the purposes of demand requirements rather than for the connection of new embedded generation projects.

Charge Setting

Metering data is used extensively when setting DUoS charges therefore we agree that metering data would be the best source of data for undertaking any calculations. This would also have the added benefit of being readily available at the Transmission/Distribution interface point across GB. However using historic metered data will not take account of planned network developments (e.g. new connecting customers and plans relating to demand side management).

Whilst it appears appropriate for exporting GSPs to be defined as those with a higher maximum export than their maximum import, this could lead to a volatile charging regime in that a GSP could change from an exporting GSP to an importing GSP year on year.

In addition, if the level of charge is based on the difference between the maximum import and maximum export it could be quite small. The pass-through of any charge could require extensive changes to the current DUoS charging methodologies. Introducing a complex charge to recover a very small proportion of revenue would not benefit the parties, nor provide the intended cost signals.

Previously a DCUSA change proposal (DCP 137) was raised to introduce charging arrangements for generators connected into generation dominated primaries. Currently LV and HVN generators are believed to benefit the network and are paid credits, the level of which is dependent on if they are intermittent or non-intermittent. The change proposed the introduction of additional tariffs (credits) which would be reduced for those who were connected to generation dominated primaries. This was to be done on a sliding scale (i.e. if the connection was forecast to become generation dominated in 5 years, 10 years etc.). Generators would be identified within the model (by Line Loss Factor Class) and they could change LLFC year on year. The low materiality of this issue and the added complexity and volatility led to Ofgem rejecting the change (11 Feb 15).

Consideration also needs to be given to generators who may incur charges as a result of volatile demand profiles (e.g. as a result of warm weather). Any charge as a result may be discriminatory and subject to potential appeals to Ofgem or the CMA.

Cost Signals

For cost signals to be effective the level of the charge is key, it must also be targeted at those able to respond. DNO and customer projects are developed over the longer term, introducing charges that could apply one year and then not the next will not provide appropriate cost signals to encourage changes in behaviour. The delays in applying the charges will also impact on the appropriate signals.

MITs Definition

Changing the definition to facilitate a new local charge for DNOs raises significant concerns as there is a wider impact on Distributed Generations. Moving the boundary specifically for GSPs could be argued as discriminatory.

¹ Set final TNUoS tariffs at least 15 months ahead of each charging year (updated to suggested period of 6-8 months)

Recovery of Costs

Any charges levied on DNOs for the operation of the Transmission network will need to be passed on to connected customers.

To ensure cost reflectivity is maintained, the reason for the exporting GSP will be important. Should a GSP export onto the network due to active network management it may be more appropriate to socialise any charge across a DNO's entire customer base. However, if a GSP exports due to the behaviour of connected embedded generator(s) it would not be cost reflective for all customers to pay the resulting charge.

Any charge targeted at individual customers would require charging methodology changes (significantly so in the case of LV and HV customers charged under the Common Distribution Charging Methodology) and would introduce further volatility within charges that are now set 15 months in advance.

In addition, as mentioned in the consultation, under the current EHV Distribution Charging Methodology, EHV and HVS generators connected prior to 2005 are exempt from generation charges for a period of 25 years following connection. This would impact on the recovery of TNUoS charges from the appropriate customers.

Longer Term Commercial Arrangements

Ofgem's "Making the electricity system more flexible and delivering the benefits for consumers" position paper issued on 30th September details the complex regulatory, commercial and structural issues that need to be addressed in the development of more flexible networks.

Charging arrangements such as those included within this informal consultation are likely to be influenced by the work undertaken to facilitate flexible networks therefore it would be premature to implement stand-alone complex changes at this time.

Conclusion

Whilst we fully recognise that networks are changing both in relation to the types and behaviour of customers connected, and also in DNOs' responses to innovative developments in active network management, there are a number of issues that need to be further explored before any specific charging proposals can be fully considered and taken forward.

**Andy Wainwright
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-Transmission Network Services
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Energy Power Distribution
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Date: 30 October 2015

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Dear Andy

Potential Transmission Charging Arrangements at Exporting Grid Supply Points

Thank you for the opportunity to respond to the above pre-consultation. Scottish and Southern Energy Power Distribution (SSEPD) is the trading name of the licenced distribution companies Scottish Hydro Electric Power Distribution plc (SHEPD) and Southern Electric Power Distribution plc (SEPD). SHEPD serves the north of Scotland whilst SEPD serves central and southern England. We also own and operate small embedded distribution systems in other areas.

We do not support the main National Grid proposal in this pre-consultation because we do not agree that TNUoS charges associated with exporting GSPs should be passed to Distribution Network Operators (DNOs) for them in turn to recover the charges from distributed generators.

We believe that the proposals are likely to have a significant impact on existing and future distributed generation, especially those connected to our SHEPD network. We also believe that the proposed implementation date is ambitious given that fundamental reforms to industry codes (CUSC and DCUSA), as well as regulatory framework changes, are required.

Our responses to the specific questions raised are set out in attached Annex 1.

If there are any aspects of this response you would like to discuss please do not hesitate to contact me.

Yours sincerely



**Mo Sukumaran
Pricing Manager**

ANNEX 1

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

Questions:-

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

We acknowledge that National Grid is obligated by its Licence to review its Charging Methodology and, where appropriate, to make proposals for changes to better meet the relevant objectives set out in the Licence.

The major growth of distributed generation ('DG') in recent years has clearly driven transmission system investment in many areas and will continue to do so into the near future. We understand that National Grid would wish to review their methodology in light of this growth to ensure that it remains fit for purpose.

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 principle, at this stage we agree that a local TNUoS export charging arrangement that may be developed should only affect those GSPs which export. However, the proposals are at a very early stage in development and we may wish to consider alternative options with the benefit of more detailed information.

In principle at this stage we believe charges should be structured in such a way that limited to those GSPs with net export (more cost reflective)

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

As the consultation acknowledges, National Grid currently levy TNUoS charges on an annual basis to suppliers, transmission connected generators and directly to some DG operators. There are therefore long-established contractual and charging arrangements which enable National Grid to charge and collect TNUoS revenue from industry participants other than DNOs.

If a TNUoS charge for DG was implemented, in our view this existing contractual and charging relationship should be developed and extended such that any new charges would be applied by National Grid directly to the registrants (in settlements) of the export metering for any DG which is considered to be liable for the charges.

This would mean that the majority of any DG export TNUoS charges would be levied to the electricity suppliers, as they are the registrants for the vast majority of DG. Under established industry supplier hub arrangements, they are currently the recipients of a range of charges which they normally pass through under their contracts with the generators. Export TNUoS charges would also be levied directly by National Grid to the operators of the small number of Central Volume Allocation (CVA)-registered DG sites, these generally being the larger embedded generation sites.

We believe that this proposal maintains consistency with existing demand TNUoS charges. We see no compelling logic in adding a further layer of charging arrangements which effectively places the DNOs in a complex intermediary role between National Grid and either the electricity suppliers or the CVA-registered embedded generators. Indeed, we believe that the approach of using DNOs to allocate and collect charges would add inefficiency and unwelcome complexity to charging arrangements overall, assuming that a viable basis for applying charges through export Distribution use of system (DUoS) could even be established.

In most cases, the DNOs' only contractual relationship with their DG customers is through each site's connection agreement, which is an enduring agreement put in place at the time of connection. Connection agreements are not established for the purpose of levying any ongoing charges and the DNO normally has no commercial contact with the DG customer after connection unless they wish to modify their connection and change the agreement.

DUoS charges are the only ongoing charges levied by DNOs and these are charged to the relevant registrant. These charges are governed by approved methodologies (CDCM and EDCM), neither of which is designed to accommodate pass through of TNUoS charging. Any changes necessary to achieve such a position would be subject to very complex, challenging and lengthy development. We further believe that changes to the distribution licences would also be required to enable any such charging to take place.

As National Grid is aware, many of the DG sites charged under EDCM are in any event subject to complete exemption from all export DUoS charges. This arises from the arrangements established by Ofgem to implement export DUoS charging for 'pre 2005' DG. Many of these exemptions, typically for comparatively large DG sites, are scheduled to continue for a further 10 – 20 years. The use of time-limited exemptions followed considerable adverse reaction from the generation community to the introduction of charges, along with indications of potential legal challenge. It therefore seems almost inconceivable that an appropriate, justifiable and non-discriminatory basis for TNUoS charging through the vehicle of DNO DUoS charges could either be developed or implemented in any reasonable time horizon.

In our view therefore it is clear that National Grid should, if further detailed proposals are justified, base further development firmly on the principle of applying charges directly to export registrants.

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

Using historical metering/settlements data has the merit that actual data is being used but also means that evidence of the effects of customer behaviour to cost messages would lag by at least two years.

Using charging year forecasts presents challenges relating to the build up of these forecasts, these generally being based on a combination of historical trends and predicted generation patterns. Arguably this approach provides a better incentive for customers to react to cost messages because they would benefit from lower charges more quickly than using the historical data approach.

An alternative 'hybrid' approach is to use the settlements data and include any known new demand and generation that would make a material impact on charges.

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

We agree that stability should be achieved on the net approach (export-import) and no doubt customers would welcome a smaller charge but to ensure a cost reflective charging base is adopted an impact assessment should be completed on all potential options. The option of a kWh charging base should be explored.

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

We agree that, in principle, including the transformers at shared exporting GSPs as part of a local TNUoS is appropriate given this is currently recovered in the residual element of a TNUoS Infrastructure charge. However, any customer contribution towards the provision of the transformer via connection charges should be taken into account.

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

We agree that it is necessary to make the change to the MITS definition to facilitate the propose charges and ensure consistency with the treatment of transmission connected generators.

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

Option 1 appears to provide a less cost reflective charge than Option 2 because the assets that potentially contribute to the local network constraint or alleviates the constraint and thus the need for reinforcement are excluded. The impact on customers and merits of both options need to be further understood. It would be helpful to provide detailed information in future consultations.

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

See response to Q4.7.

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

We do not recommend recovery of any local TNUoS charge through DNOs for the reasons given in our response to Question 4.4.

However, if a local TNUoS charge is passed to the DNOs to recover, the following issues need to be addressed:

- changes to Distribution Licences would be necessary to allow recovery of the charges as a 'pass through cost'. The current RIIO ED1 settlement for DNOs did not consider recovery of the proposed charges, hence there is no provision for such costs, leaving DNOs exposed to unforeseen and potentially unrecoverable charges, even taking into account existing uncertainty mechanisms. Changing the basis of a price control mid-way through the relevant period introduces uncertainty and risk for both network operators and customers.

- changes to DCUSA, CDCM and EDCM charging methodologies would be necessary to recover these charges on a cost reflective and non-discriminatory basis. Issues are likely to include
 - o many generators who are connected at lower voltage levels and are charged through CDCM will contribute to GSP export. One of the principles underlying CDCM is a common structure of charges across each DNO licence area. Allocating new TNUoS charges for exporting GSPs only to some generators who are deemed to be contributing to the export at certain locations is at odds with this principle and would lead to localised DUoS charges.
 - o localised DUoS charges would be very complicated to administer compared to current arrangements and significant billing system changes would be required, incurring significant costs. From a customer understanding perspective, localised charges would also be very complex and would add a considerable communication and administration burden to DNOs.
 - o there are clearly going to be difficulties in determining exactly which customers are driving the rise in export from any GSP. The rise could be due to demand drop off combined with increased DG or growth in DG connected by non half hourly (NHH) metered customers which DNOs lack full visibility of.
- a large section of distributed generators have time limited export DUoS exemptions which typically do not expire for many years ahead. We believe that any attempt to recover exporting GSP charges from this group presents a significant contractual and commercial issue which must not be underestimated. Ofgem direction on changes to these existing arrangements would be required.
- engagement with DGs to recover these 'third party' charges is likely to be challenging commercially given the costs relate to transmission not distribution.

Section 5 Longer term commercial arrangements

The potential for DNOs to take on a DSO role i.e. taking on responsibilities for local energy balancing (as opposed to managing capacity) through commercial arrangements with generators and responsive demand is being considered by electricity industry stakeholders. However, it is at a conceptual stage and being trialled as part of potential smart grid solutions schemes. It is also being considered in other contexts by National Grid and more widely by other parties (DECC, Ofgem, European Commission / regulators).

DNOs are currently trialling a range of different commercial and technological arrangements that may allow them to incorporate flexibility options (such as energy storage, demand side response, voltage control and other options) in their management of the distribution networks. The ultimate aim of deploying these arrangements and options is to incentivise the production and consumption of electricity in a manner which should lead to lower overall distribution network costs.

Ofgem have recently published a position paper¹ stating their intention to facilitate the increased use of these types of techniques to deliver customer benefits. We acknowledge that

¹ <https://www.ofgem.gov.uk/publications-and-updates/position-paper-making-electricity-system-more-flexible-and-delivering-benefits-consumers>

in the future the DNO's role is likely to be more active in network management than is currently the case.

However, these arrangements and options are at a very early stage of commercial and technical development and will fundamentally affect the industry trading and settlement arrangements, which currently are delivered around 'supplier hub' principles. We believe that, given the issue raised in this consultation is a transmission system issue, it is more appropriate that this change should form part of a wider review of transmission charges, taking cognisance of other and wider industry work.

We believe that it is appropriate to review the TNUoS charging arrangements in light of the changing demand and generation patterns being imposed on the transmission network now and in the future. It is appropriate to ensure the charging methodology recognises these factors and reflects the cost drivers. The charging structure and basis of charges may well need to develop to meet different circumstances and new challenges but in the current price control period we do not support any mechanism which would pass exporting TNUoS charges to DNOs.

RE: Potential Transmission Charging Arrangements at Exporting Grid Supply Points (GSP)

UK Power Reserve is the leading independent developer and operator of smart, flexible power generation in the United Kingdom. Founded by energy experts and investors in 2010, UK Power Reserve combines a specialist team and a portfolio of flexible energy generation assets.

We agree that the drivers for this project into investigating the balances between transmission and distribution regards charging and balancing is relevant and fully justified. We are also overall supportive of the stated methodologies within the proposal.

We support option 1 as being the clearest and simplest implementation option as it extends the existing arrangements in the desired direction. We would however highlight the potentially perverse measures of National Grid having procured services such as Short Term Operating Reserve, Demand Side Balancing Reserve, Frequency Response etc. and publishing its commitment to procure more demand side services to fulfil its requirements (a hoped for 50% share for demand side measures) and yet is proposing measures to potentially discourage any such endeavour through punitive charges.

We believe that the growth of embedded generation is split between intermittent sources (wind and solar) and conventional plant that has grown to some extent as a result of a demand for generation that can assist in meeting the Triad peaks. In our view the exporting GSPs are largely as a result of embedded renewable generation and perhaps this is worth further investigation on if such changes to arrangements would have greater than anticipated impacts.

In our opinion it is critical that existing plant, or plant in the process of being constructed is grandfathered from any future proposals that would result from this alteration of the charging arrangements. The significance of such a change to the investment decisions made under plans such as the capacity market auctions would represent an irredeemable change to the nature of the marketplace and contracts already signed under an existing framework.

UK Power Reserve is already in partnership with several demand side customers for the provision of Demand Side Balancing Reserve and other demand side reserve services and believes this provides National Grid a strong option for combatting peak demand and supporting system stability and agree with the proposal to involve demand side services in the provision of commercial arrangements to deal with the issues National Grid and the DNOs are facing.

Yours sincerely

Ian Tanner
Senior Energy & Operations Analyst
UK Power Reserve

Dave Corby
National Grid

By email only

30 October 2015

Dear Dave,

Informal Consultation on Potential Transmission charging Arrangements at Exporting GSPs

Thank you for the opportunity to comment on this consultation. This response should be regarded as a consolidated response on behalf of UK Power Networks' three distribution licence holding companies: Eastern Power Networks plc, London Power Networks plc and South Eastern Power Networks plc. For convenience, the three licensees are collectively referred to as "UK Power Networks" throughout. Please note that our response is not confidential and can be published via the National Grid website.

We have provided answers, where appropriate, to the consultation questions in the appendix to this letter but there are a number of key points that we would like to make:

- The majority of this work by National Grid is a useful evolutionary development to TNUoS charging methodologies for those situations at GSPs where the maximum export exceeds the maximum import as a result of embedded generation and we suggest that National Grid take this work forward and produce a formal change proposal to its charging methodology on this basis.
- Before changes to the transmission charging methodologies can be agreed it will be necessary to consider and agree how any changes are to be reflected in DNO charging methodologies and in DNO price controls given that the latter have just been fixed until 2023.

If you have any questions or queries on this response then please do not hesitate to contact me using the details below.

Yours sincerely



Keith Hutton
Head of Regulation, UK Power Networks

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Appendix – UK Power Networks’ response to the questions set out in the consultation

CHAPTER: Three

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

All licenced network operators have overarching obligations to develop and maintain efficient and economic networks¹. These are reflected into their respective charging methodologies governed by CUSC² and DCUSA³ requiring these to be cost reflective. If National Grid has identified new drivers of transmission investment then consideration must be given as to whether and how these need to be appropriately reflected into the charging methodology. The same situation would apply to DNOs; if new costs arise then we would need to consider how these should be reflected appropriately into DNO charging methodologies.

CHAPTER: Four

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

Yes, we agree that any local TNUoS charging should be limited to those GSPs which export power to the transmission network. The only logic for considering the introduction of local TNUoS at GSPs is because of exports and so charging should be restricted to the relevant GSPs.

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

Should local TNUoS charges be introduced then the party who should be liable for those charges is the party (or parties) who are the underling drivers of the transmission investment. From a practical perspective this will need to be a party that National Grid has an existing relationship with or establishes a new relationship with. If the relevant parties have BEGAs⁴ or BELLAs⁵ then National Grid already has a relationship with them. However, applying local TNUoS charges down to embedded generators on this basis would expand the requirement to accede to CUSC to a wide range of smaller customers connected to DNO networks (i.e. those without BEGAs or BELLAs). This is probably unreasonable and so pragmatically means that either the Supplier or the DNO (who are already CUSC parties with relationships with National Grid) should be the counterparty.

This does not, however, displace the underlying premise that the triggering party should bear the costs. If the Supplier is the counterparty then the charges should be allocated using appropriate modifications to the National Grid charging methodology so that the charges are applied to the party causing the costs. If the DNO is the counter party we would expect to see modifications brought forward to DNO charging methodologies so that the DNO passes the charges onto the party causing the costs.

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

Ideally a charging methodology should be forward looking so that it drives future customer behaviour rather than “penalising” past behaviour. Therefore, we believe that forward looking charges should be calculated and published for GSPs where forecasts suggest that exports may

¹ Electricity Act 1989 Section 9

² Connection and Use of System Code for Transmission Licensees.

³ Distribution Connection and Use of System Agreement for Distribution Licensees.

⁴ Bilateral Embedded Generation Agreement

⁵ Bilateral Licence Exemptible Large Power Station Agreement

exceed imports but that charges should only be levied where the metered data indicates that this has actually occurred. This would provide a cost signal to the market.

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

We agree with the principle that the chargeable quantity should be the excess of the maximum export over the maximum import. Any other solution would prompt a very significant disturbance to customers' charges.

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

We do not agree with the proposed approach as the calculation suggested does not take account of the excess of exports over imports applied to local TNUoS charges. The same excess export principle should apply to any charging for infrastructure transformers.

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

Based on the information provided we are unable to provide detailed feedback on the proposed MITS node definition changes – we believe that more detail from yourselves is required to enable us to fully understand and model the potential impacts.

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

Again it not clear whether option 1 would apply to all exports or only the excess of export over import. The latter is appropriate (having been established in 4.3 as the charging base) but the former is not. This approach uses a generic tariff rather than a site specific one. We believe that more locational representative tariffs are appropriate particularly as the embedded generators will be receiving site specific tariffs based upon their location on DNO networks, on this basis the generic tariff is not appropriate.

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

We prefer this approach is over option 1 because of its better locational signal, however it should only apply to those GSPs where the maximum export exceeds the maximum import (as established at 4.4 above).

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

We consider that the recovery should be via the Suppliers of the relevant embedded generators. We would be interested to see National Grid provide a modified TNUoS charging solution so that charges could be applied on the same basis as charges to existing demand and generation entering or exiting the transmission system. This could be achieved by applying a GSP correction factor to embedded generation units so that the metered units match the units entering the transmission system from an importing GSP group.

However, if local TNUoS charges relating to embedded generators are levied on DNOs (which seems to be an assumption of National Grid despite the counterparty being consulting upon in 4.2 above) then there are two aspects to this question. Firstly the recovery mechanism of the charges by DNOs from their customers and secondly the treatment of the charges under DNO price controls.

Any cost arising to DNOs from local TNUoS charges should be incorporated into an appropriate DNO charging methodology so that cost falls on the triggering party or parties.

DNOs have just agreed price controls under the ED1 framework up to 2023 and were agreed at a time when methodologies clearly stated that these costs would not fall on DNOs. Therefore, any treatment of local TNUoS should be treated as a pass through under DNO price controls and any required investment should be initiated by National Grid.

CHAPTER: Five

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?*

At the margin every domestic customer who replaces a tungsten filament bulb with a compact fluorescent or connects an electric motor to the network is driving costs to the system operator in managing the system. The idea of pushing BSUoS down to all persons given the massive increase in complexity it would create for customers is not appropriate. We would suggest that the current arrangements need to be modified only so far as parties from whom the System Operator procures services should be paying BSUoS as by definition these are the parties capable of materially affecting the transmission system.

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 introduction of a new commercial arrangement potentially impacting Suppliers, distributed generators and DNOs calls for wider consideration by government, regulatory authorities not solely for the transmission system operator. In the current timeframe National Grid should consider arrangements within the existing legal and regulatory framework.

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

The appropriate system operator should be best suited to design and procure services to meet their balancing needs. The design process should incorporate appropriate involvement with industry stakeholders.

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

We believe that National Grid should not presume the presence of aggregators and should consider all potential models that could exist within the current legal and regulatory framework to ensure the most appropriate solution.

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

We believe that TNUoS arrangements do not need to be reviewed more wildly as evolutionary change to adapt them to reflect situations where the maximum exports at some GSPs are greater than their maximum imports should be the focus of effort at present.

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?*

The proposals looking at the potential TNUoS charging arrangements for those GSPs where the maximum export exceeds their maximum import are reasonable, appropriate and forward looking. We would suggest that option 2 is closer to a preferred way forward than option 1 because of its better locational signal.

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?*

We have no further suggestions to make at present.

NGET Consultation Paper

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

Vattenfall Wind Power response, 30th October 2015

Vattenfall Wind Power develops, builds and operates onshore and offshore wind farms in the Great Britain, including several distribution and transmission connected sites that have the potential to be significantly impacted by the changes proposed in this consultation. Our specific responses to the questions posed in the consultation are set out below. We would welcome the opportunity to discuss our responses with you and to participate in future industry forums on this matter.

Andy Causebrook, 30th October 2015.

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

Vattenfall recognise the substantial discrepancy between the treatment of distribution and transmission-connected generators with respect to transmission charging and welcome a review of means to address this. This discrepancy is particularly evident in Scotland and will be widened further by the removal of the small generator discount for 132kV-connected generators from April 2016. Vattenfall therefore welcomes the work carried out by National Grid and the opportunity to respond to the consultation but believes that there is a lack of evidence to justify that the proposed changes will deliver the desired objectives with respect to reducing discrimination or facilitating effective competition. Furthermore there are important unintended consequences of National Grid proposals which would compound the impact on transmission-connected generators, as detailed in Q4.6 below.

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

We agree that charging should be limited to cases where changes would drive additional investment. However, we also note that increases in GSP export can derive from either increasing generation or decreasing load. We also note that there no local TNUoS charges for demand customers and therefore the introduction of charges for generators associated with exporting GSPs, would discriminate between generation and demand classes of users. For example, a commercial generator and commercial consumer, with equivalent capacity and scale, would be treated differently under the proposed arrangements. We also note that suppliers are currently incentivised to reduce demand in areas with large numbers of exporting GSPs because of the strongly positive demand TNUoS charges.

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

If such charges were introduced, the DNO would appear to be the most appropriate intermediary. However, without knowing how a DNO would attribute charges to distribution-connected parties, National Grid could wrongly install an ineffective/unsuitable signal to users, including distributed generators. Therefore we strongly advise that this proposal could only be progressed in tandem with a relevant associated distribution charging change proposal.

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

No comment.

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

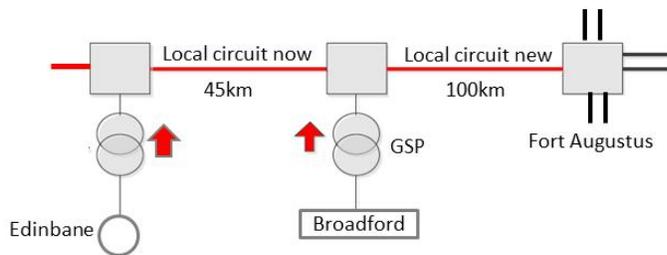
If such a charge were introduced we agree that using the difference between maximum import and export would be the most appropriate method. However, we note that such charges would discriminate between generation and demand classes of users.

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

Such charges would discriminate between generation and demand classes of users. This is further highlighted by the fact that generation and demand users triggering reinforcement of Transmission Connection Assets at a GSP are both liable for the associated capital charges but under the current proposals only generators would pay the “local transformer tariff”.

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

Important: We are very concerned about the unintended, and potentially severe, impact of this proposed change on certain transmission-connected generators, using Edinbane wind farm as a pertinent example:



Edinbane is a 132kV-connection generator in Skye (TNUoS Zone 4) with a local circuit TNUoS tariff of £6.1/kW based on a 45km local circuit length to the nearest MITS substation (Broadford GSP). The proposed change of MITS definition would make this site vulnerable to a change in the status of Broadford GSP to an exporting GSP, as shown in the above diagram. This change, outside its own control, would result in a more than tripling of its local circuit TNUoS charge. Such a change would compound the removal of small generator discount in 2016 resulting in an extremely adverse change in its commercial position. Other transmission-connected generators could be similarly impacted in this unintended manner.

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

National Grid’s argument that some distributed generators receive an embedded benefit from their electricity supplier reflecting the offsetting of additional transmission infrastructure costs at GSPs is unfounded because suppliers (and hence its demand customers) are not liable for local TNUoS charges. We therefore reiterate that such charges would discriminate between generation and demand classes of

users and cannot be shown to provide effective signalling unless progressed in tandem with a relevant associated distribution charging change proposal.

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

Such charges would discriminate between generation and demand classes of users and cannot be shown to provide effective signalling unless progressed in tandem with a relevant associated distribution charging change proposal.

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

We agree that any such charges should be borne by the party who can respond to the charging signal and therefore the socialisation of an exporting GSP charge across the entire charging base of a DNO would be inappropriate. This emphasises our previous point that without knowing how a DNO would attribute charges to distribution-connected parties, National Grid could wrongly install an ineffective/unsuitable signal to users, including distributed generators. Therefore we strongly advise that a proposal of this type can only be supported if progressed in tandem with a relevant associated distribution charging change proposal.

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?

We are not aware of commercial arrangements that will facilitate provision of balancing services from a significant population of distributed generation. Without broad-based arrangements it would not be appropriate to apply BSUoS charges to all distributed generators.

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?

We agree that further commercial arrangements could better facilitate constraint management.

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

No comment.

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

No comment.

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

The most significant discrepancy between the treatment of distribution and transmission-connected generators relates to wider TNUoS charges. However, we believe that there is a lack of evidence to justify that introducing a wider TNUoS arrangement for distributed generation will deliver the desired objectives with respect to reducing discrimination or facilitating effective competition.

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?

We believe that there is a lack of evidence to justify that the proposed changes will deliver the desired objectives with respect to reducing discrimination or facilitating effective competition. Furthermore there are important unintended consequences of National Grid proposals which would compound the impact on transmission-connected generators, as detailed in Q4.6 below. The proposals also introduce new discrimination between generation and demand classes of users.

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?

No comment.

30 October 2015

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Dear Mr Corby

Informal Consultation on Potential Transmission Charging Arrangements at Exporting Grid Supply Points

Welsh Power owns and operates 150 MW of embedded generation. We are therefore very interested in any proposals to charge exporting GSPs. Below we have tried to answer the questions posed by National Grid (NG), but we would note that charges need to be considered in their entirety and not on a somewhat ad hoc basis. Both the TO and the DNOs need to provide a set of coherent signals to generators about where to locate and when their operation is most useful. These signals need to be understood by investors, transparent and ideally easy to forecast.

Welsh Power would urge NG to work with Ofgem and the DNOs to create a more coherent charging regime. At the same time, NG should also be looking to get benefits from embedded generation where it can help support the system by providing services as required, for example the development of services like STOR that address new problems arising from renewable generation. We would be happy to discuss these issues further.

Consultation questions

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

Yes we agree. However, it is vital for investors that we can see where these GSPs are now and where they will develop in future. Welsh Power does not wish to, and has no need to, invest in areas where exports incur additional charges. We would therefore wish to see any charges accompanied by clear signals to investors about locations where embedded generation would be economic.

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

Welsh Power believes that the DNOs are best placed to be the party liable for potential TNUoS local charges. DNOs have a contractual relationship with all Distributed Generators (DG) and large demand users on its network as well as National Grid. However, there may be a need for changes to the DNOs' licences to allow for the collection of TNUoS charges from DNO connected parties. There would also need to be consideration given to how these charges are passed by the DNOs to the DG or other customers on their systems. We would like to see them incentivised to consider further charging changes to create more robust framework of economic signals around the operation of DG and customer demand.

Making the DNOs responsible for TNUoS local charges could also help facilitate the move towards a Distribution System Operator (DSO) model in GB if the right incentives are put in place. DNOs need to be encouraged to incentivise changes in flows onto and off the transmission system, as well as considering other ways to manage their systems with the growth of "smart networks".

NG should not attempt to charge DG directly because it has no commercial relationship with them; there is no way that NG can know which DG is creating the specific flows at which the charges are aimed.

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

Using historic metering data or forecasts to determine the charging base for exporting GSPs both have their problems. Historic metering data may be most robust, but consideration has to be given to issues such as outages and the treatment of new generation. Forecasts may be able to account for these problems, but there is always a risk with forecasting that they fail to see the unexpected and can therefore be highly inaccurate with the benefit of hindsight.

Using real, but industry forecast data, such as week 24 combined with the use of load factors may create imbalance between accurate, but forward looking charges. For all parties though there are wider issues around the notice periods given for the charges and the stability of the charges. These need further consideration.

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

The charging base proposed in the consultation (the difference between the GSP's maximum export and its maximum import for GSPs with a higher maximum export than their maximum import) seems appropriate.

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

Welsh Power believes that there needs to be further consideration given to the way new DG are treated under the proposed approach to transformers at a shared exporting GSPs. There are issues around equitability and stability that will have to be addressed.

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

While we can see the merits in changing the definition of a MITS node there may need to further consideration of the implications to other charges.

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

This would appear to be a relatively robust solution, but as already noted there is a need to consider if this is transparent enough and if parties can respond to the signals created. As part of that response, parties will need to know the timing of charging notices and how this will feed into the DNOs' own charges. This is an opportunity for the DNOs to consider the benefits offered to DG that operates at times when the system needs support.

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

The local circuit and substation charge appears to be quite volatile and is therefore likely to be less welcome by the DG that will be impacted by these proposals.

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

The DNOs need to consider their own charging methodologies and the signals they are sending to all their customers. Charging to recover local TNUoS, and their other costs, needs to be transparent and allow users to forecast their charges.

10. *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?*

Welsh Power believes that BSUoS charging should continue to be applied on a net basis rather than on a gross basis because costs are dependent on net (not gross) flows. Using net flows as the charging basis should incentivise DNOs to work on their roles as DSOs where the appropriate signals would incentivise them to actively balance their own distribution networks.

As NG also procures balancing services from DG these parties provide a benefit to customers by allowing the System Operator (SO) to secure services at the most economic costs. To then charge these parties BSUoS would then require that they pass the cost back to NG in their service price, which would seem to make the exercise somewhat pointless.

11. *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?*

Welsh Power believes that NG should be actively working with DNOs to ensure that assets that are able to be used for managing both the transmission and distribution system should be able to do so without the need for further direct contractual agreements. There seems little appetite for developing new services and working with DG to enhance system security. We believe that this is a missed opportunity for GB customers.

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

Both NG and the DNOs, acting as DSOs, could procure services if they wish to. There may also be a role for aggregators. However, the important thing is to develop the services that the DG can provide and offer reasonable contractual terms.

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

If the DG wishes to use aggregators it can chose to do so. It is important that the contractual structure does not stop this, but also that services provided via aggregators can be checked so that there are no “phantom” providers being paid without delivering the services contracted for.

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

The wider TNUoS arrangements should not be reviewed at this time. The TRIAD system is providing the type of system response that NG seems to need to reduce peak demand, though moving all TNUoS charges to the Suppliers would increase the TRIAD signal. The EU network codes are also due to be implemented over the coming years and may require a review of TNUoS arrangements.

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

Welsh Power is not convinced that the options laid out in section 4 create the right signals. It may be more prudent to look instead at the distribution signals which can be used to manage the DNO networks and thus their impacts on the transmission network.

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

Where DG does pay for access rights to the transmission network then that should give them rights to transmission access like other connected users. This will need some further consideration.

If you or your colleagues have any questions please do not hesitate to contact me.

Yours sincerely



Alex Lambie
Chairman

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

Drivers for our work

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

The reasons for the work being undertaken seems sensible

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?

Yes, under a cost reflective charging methodology this should be the underlying aim.

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

A commercial arrangement should be put in place between the direct cause of the GSP exporting and National Grid i.e. it should be solely between Grid and the generators. For generators connected at HV and below the DNO pays credits on all units generated and for non-intermittent generators connected at EHV the DNO pays credits for units exported in the super red. It would seem strange for the DNO to pay these to the generators and to also pay National grid for generator producing too much of these units.

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

This is reasonable.

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

No

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

No

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

No. It would seem reasonable to change to accommodate exporting GSPs

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

None

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

None

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

Currently DNOs have no licence facility to pass these costs on to end users in a similar way to how connection charges are passed through. If that facility did exist it would then take a change to the duos charging methodologies in order for those costs to then be reflected in use of system charges. This would require a change to the DCUSA. It would seem more sensible and more direct for these new charges to be passed through by National Grid direct to the embedded generators at exporting GSPs.

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?

Commercial arrangements should be extended to cover these generators to ensure equitable treatment.

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?

Yes options should be explored

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

It is more efficient to go directly to the generator; they are the party causing the exporting GSP issue.

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

Yes that would seem appropriate.

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

Strong growth in distributed generation is a reality and as such the impact of this type of customer on the transmission network needs to be fully understood, including accessing improved data. As such arrangements should be reviewed to ensure generators and their impact is fully accounted for. Also, in an era of SMART networks, demand response should be reviewed.

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?

Yes

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?

Yes, but these should be charged directly to the end customer so that the benefit could be realised.