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Dear Colin,

Enduring Transmission Charging arrangements for distributed generation

I refer to Ofgem's consultation regarding the various options for enduring transmission charging arrangements for distributed generation. I have attached SSE's response to the consultation and if you have any questions or require any further information about the proposals set out in our response, please give me a call.

Yours sincerely,

Rob McDonald
Director of Regulation

Enduring Transmission Charging arrangements for distributed generation – SSE response to Ofgem consultation

1. Introduction

1.1. Ofgem's consultation on enduring transmission charging arrangements for embedded generators has raised a number of issues. It has also, in our view, misrepresented the current arrangements in that we believe all usage of the transmission system as defined in the charging methodology is paid for. Our reasons for this are set out in appendix 1 to this response. However, it is not clear that the charging arrangements correctly reflect the uses made of the transmission system, or that the other market arrangements provide the necessary tools to manage the system in real time.

1.2. We therefore believe that the shortcomings of the existing arrangements need to be identified so that revised arrangements can be introduced and implemented. Against this background, it would then be possible to identify the strengths and weaknesses of the different approaches mentioned in Ofgem's consultation and if any other approaches could be considered.

1.3. In responding to this consultation, we have therefore set out the issues that need to be addressed, reviewed the options set out by Ofgem and considered alternative options before setting out our proposals for the way forward.

2. Issues to be addressed

Exporting GSPs

2.1. Ofgem has stated in chapter 4 that one of the issues to be addressed is "Exporting GSPs without access rights". The two main aspects to the issue are characterised as operational concerns on control of the network, and that "some parties do not pay for the use they are making of the transmission system".

2.2. While we understand the operational concerns, we do not believe there are any parties not paying for the use they are making of the transmission system. The current charging methodology identifies two types of user of the transmission system, generators and suppliers. There is a system in place to ensure that generators liable for transmission charges are defined and charged according to the methodology. Suppliers are charged for their offtake net of embedded generation within a GSP group at system peak. We have expanded on this point appendix 1.

2.3. It is clear, therefore, that the existing methodology captures all usage of the transmission system within its current definition of the cost drivers of transmission investment. It is questionable whether this is a correct assumption about cost drivers given the current context of increasing embedded generation and exporting GSPs. The issue of charging therefore falls under the second of Ofgem's issues to be addressed, namely the cost reflectivity of charges.

2.4. This means that the issues to be addressed in respect of exporting GSPs are limited to:

- Whether the procedures to ensure there is sufficient transmission capacity are in place, and;
- Whether NG has adequate means to manage flows on the transmission system.

Adequate Transmission Capacity

2.5. When a generator applies for connection to or use of the transmission system, the TO (NG in the case of applications in E&W and SPT or SHETL in Scotland) is obliged to ensure that the transmission system complies with the GBSQSS. A large power station, even if connecting to a distribution system, is obliged to apply for use of the transmission system. This ensures the ability of the GB transmission system to transmit power is maintained for a number of predefined eventualities. Indeed many of the GSPs in the SHETL area are specifically designed to export and the transformers at these GSPs are rated for the level of potential export rather than customer demand.

2.6. Connection of new generators is prevented until the necessary reinforcements are made. However, in E&W this definition of a large power station is 100MW, while in Scotland it is 30MW (SP area) and 5MW (SHETL area). This discrepancy could lead to perverse incentives to size generating stations below the relevant threshold, and, particularly in E&W, could lead to lack of transmission capacity.

2.7. It is therefore clear that some refinements to the planning process (particularly in E&W) may be required to ensure the provision of adequate transmission capacity.

Constraint Management Tools

2.8. While the process outlined above ensures that adequate transmission capacity is provided within the planning time frame, NG also needs a mechanism to manage the flow of power into and across the transmission system in real time. To manage constraints on the transmission system, NGC uses the Balancing Mechanism (BM) bids and offers to pull back generation behind a constraint. Generators participating in the BM will have their TEC granted through a BEGA or a BCA. Since TEC is granted on a nodal basis, a very targeted approach to constraint management can therefore be taken.

2.9. However, while the supplier can participate in the BM in the same way (and can respond to bids and offers by adjusting their embedded generation output) it is not clear to NG at which node the supplier may be offering to reduce generation. Therefore this tool is ineffectual in managing constraints even though it can be used for energy balancing since the latter requirement is non-locational.

2.10. It is possible to foresee a situation where a constraint needs to be dealt with, but the only generators available to reduce their output are contracted to suppliers, and either have only a "BELLA" in place with NG or are small generators without specific agreements. It is therefore clear that the tools currently available to NG to manage the transmission system may not be sufficient against a background of increased embedded generation.

Cost Reflectivity & Perverse Incentives

2.11. The second issue identified by Ofgem that needs to be addressed is cost reflectivity. As argued in paragraph 4.4 of the consultation, it is clear that the impact of a single incremental MW of generation on flows across the network is the same regardless of the voltage at which the generators connect. It is also true that the impact of an incremental MW is the same regardless of the capacity of a generating station. However the current framework of transmission and distribution charging coupled with regional differences in the Grid Code definition of a "Large" generator and regional differences of which assets are classified as transmission creates an environment of perverse incentives.

2.12. For example generators pay a different charge per MW of transmission capacity required dependent upon the connection voltage (i.e. transmission or distribution) and the size of the generating station.

2.13. It is clear that the regime of charging suppliers for embedded generators via the netting off arrangement might not be cost reflective and creates perverse incentives on generators to connect to distribution systems rather than transmission. This can also affect location choice since a 132kV connection would be classed as transmission in Scotland but distribution in E&W. Also there is a lack of consistency of charging arrangements relating to the size of the generating station.

3. Options for an Enduring Framework

3.1. In light of the issues set out above, Ofgem have identified a number of options for an enduring charging arrangement. Our comments on each of these and strengths and weaknesses are set out below.

Option 1 – Do Nothing

3.2. This option would affirm the existing arrangements, particularly that the transmission capacity at peak demand is driven by suppliers' offtake (net of embedded generation) at system peak. It therefore implies that the net TNUoS charge paid by the supplier is cost reflective of the impact of all that suppliers contracted embedded generation on the transmission system.

3.3. This illustrates a further issue with the current charging methodology. Chargeable generators pay a capacity charge (whether they use the capacity or not), whereas suppliers pay a usage charge based on their actual net take at system peak.

3.4. While it is not envisaged that a supplier's net take would ever be negative (i.e. that a supplier's contracted embedded generation exceeds the demand of the supplier's customers), it is clear that across the suppliers portfolio, some individual GSPs could be exporting, even at peak.

3.5. The "do nothing" option would therefore fail to address the issue of cost reflectivity of charges.

Option 2 – De-energise plant that spills

3.6. As stated in 2.5 above, we believe that the existing planning framework ensures that there is sufficient transmission capacity available to cater for embedded generation. Whether the embedded generator contracts directly with NG through a BEGA for access rights, or through a supplier (with a BELLA with NG where appropriate) is in fact irrelevant.

3.7. The CUSC right under 5.2.1 can only be used if the user's equipment poses a threat to the transmission system. If the DNO and the transmission licensees have complied with their licence obligations in designing the system in accordance with the GBSQSS, then it is clear that a threat could only be posed in case of an unsecured event under the GBSQSS. Only in these extreme circumstances would 5.2.1 be exercised.

3.8. On this basis, we believe that option 2 does not in fact address the problem of providing NG with the means to manage the system and would undermine existing arrangements where GSPs are specifically designed to export. Furthermore, in cases where there are a number of generators behind the "spilling" GSP, arrangements would have to be put in place to choose which generator to de-energise.

Option 3 – Amendments to the charging model

3.9. Amendments to the charging model could go a considerable way towards dealing with the cost reflectivity of charging but would not address the problem of managing the system. Any amendments would need to address the discontinuity in charging for generators connecting to the 132kV system. The definition of "transmission" and "distribution" is arbitrary and the different definitions in Scotland compared to E&W causes a further distortion in charging.

3.10. However, the physical attribute, i.e. the voltage, is a subject to physical limitations rather than arbitrary definitions. We therefore believe that the charging arrangements for the <u>132kV system</u> should be consistent across GB reflecting this physical property rather than its legal definition. This could be achieved by redefining 132kV as a distribution voltage in Scotland. However, we believe that this would be disproportionate in the circumstances. Instead we believe that the 132kV costs should be separately identified in the Scottish transmission licensees' areas and charged separately. This would then be consistent with the approach in E&W. NG's charging model should then be based on the "supergrid" of 275 and 400kV circuits as it is in E&W.

3.11. The 132kV charge could be made on Scottish distributors for incorporation into the DNO charging methodology. This would best mirror the arrangements in E&W.

Option 4 – Extend DCLF ICRP model to parts of the distribution network

3.12. This option is the mirror image of the proposal in 3.11 above. This might be a more consistent way to identify usage of the supergrid network for embedded and Scottish 132kV connected generators. However, it would not overcome the difficulty of 132kV cost recovery being on a different basis in Scotland compared to E&W unless the responsibility for charging for all 132kV network usage fell to NG.

3.13. Ofgem claim that this approach would remove the perverse incentives to connect at distribution as opposed to transmission voltages. However, the "incentive" to connect at distribution rather than transmission operates on a number of levels. Transmission charging is clearly one of these, and the possibility of avoiding TNUoS charges by being embedded is a key factor. However, embedded generators also get the benefit of a payment of the supplier TNUoS charge to the extent that they are generating at the triad. It was partly this discrepancy that led to the 132kV generator discount in Scotland, and this would also need to be addressed before the discount could be terminated.

3.14. The remaining incentives relate to the proportionality of contractual forms necessary to participate in the market and the obligations these bring. Small embedded generators prefer to avoid the complexity of CUSC and BSC and so contract with suppliers. The charging framework also needs to address these issues.

3.15. For NG to assume responsibility for all 132kV cost recovery would clearly achieve a consistent basis for charging but we do not believe that the DNOs would be prepared to delegate charging responsibility for part of their network to NG.

Option 5 – Amend use of size definitions as the basis for charging and contractual arrangements

3.16. Discriminating between generators on the basis of size is a feature of the existing arrangements that, to some extent, causes the problems that this consultation is addressing. Aligning the geographical definitions of small, medium and large generators would remove any perverse geographical incentives caused by this discrepancy, but would not on its own address the charging related issues or provide the necessary tools to NG to manage the network.

3.17. This option would only be useful in conjunction with other measures to address, for example, the 132kV issues.

Option 6 – Creating a consistent liability for charges

3.18. At present, there is not a consistent liability for charges for generators across GB. Conversely, suppliers and directly connected customers do have a consistent liability for charges, since all demand customers even down to the smallest low voltage connections pay a transmission use of system charge.

3.19. If the charging methodology were revised such that there was a locational tariff payable by all parties (equal and opposite for generation and supply) and a residual "cost recovery" element paid by suppliers, this would create a consistent charging methodology and limit embedded benefit to areas where the generator charge was negative.

3.20. We believe that it should be an objective of this review to create such a consistent liability for generators.

Option 7 Agency Models

3.21. While it is right that an embedded generator does not know the extent of its potential impact on remote parts of the network, the generator will require access rights for its full output at the point of connection. It is for the network operators to assess its impact on the wider network and ensure that adequate capacity is available. Charging is therefore ancillary to this obligation.

3.22. An extreme version of agency rights would be for DNOs to contract with NGC for capacity for both demand and generation at points of connection to the transmission network. While this would greatly simplify the contractual arrangements, it would also represent a fundamental change to the methodologies and would also not resolve the 132kV discrimination issue. We therefore do not support agency models as described in the paper.

4. Other Options

4.1. In our view, none of the options identified by Ofgem would address all the issues identified in section 2 above. There are merits in many of the options and we believe the optimum solution should have the following features:

- Deal more effectively with exporting GSPs
- Removal of "distribution" vs "transmission" connection incentives, particularly for 132kV connections
- Removal of size-related incentives
- Removal of perverse short run incentives
- Consistent and equitable charging arrangements for all generators

Dealing with exporting GSPs

4.2. In many cases, GSPs are designed to export to the transmission system. However, the planning process might not be sufficient to ensure there is adequate transmission capacity to cater for additional export.

4.3. The Bilateral Connection agreement for each GSP should therefore specify a maximum import capacity and a maximum export capacity. This is not a "TEC" as currently defined and would therefore not confer any liability for charges on a DNO. It would instead be a "connection entry capacity" and so mirror the arrangements for demand, where a DNO caters for his network demand by contracting for a GSP of adequate capacity.

4.4. Specifying the maximum export would then oblige the DNO to apply to NG for any additional export requirements of his customers, thus ensuring that the transmission system has adequate capacity.

4.5. A refinement of this would be for the DNO to introduce generation management schemes where it was uneconomic to provide a further increment of network capacity. Such a scheme is already in place in Orkney, for example.

Treatment of 132kV in Scotland

4.6. As a first step, we believe the artificial distinction between the 132kV system voltage should be removed. This would best be done by redefining the Scottish 132kV system as distribution, rather than the other way round, since no change of ownership would be involved. However, since this would require primary legislation, it might not be a proportionate response to the problem. Instead, we believe that only the 275 and 400kV supergrid should be included in the GB ICRP charging methodology.

4.7. The costs of the Scottish 132kV system should be separately identified for the two Scottish transmission licensees and charged on a similar basis to the E&W 132kV system. One option is for NG to charge this to the relevant DNO for inclusion in the DNO charging methodology. This approximates to the pre-BETTA situation in the north of Scotland where the majority of the 132kV network was classified as "exit" and charged to the DNO. Alternatively it could simply be incorporated in the supplier non-locational charge as a 132kV supplement.

Removal of size-related incentives

4.8. There are two aspects to this, avoidance of TNUoS charges, and avoidance of Grid Code/Licence/CUSC/BSC obligations. The key issue, we believe, in deciding at which point any size-related incentive should cease is the point at which it becomes impractical for the system operator to manage the individual generator in real time.

4.9. Choosing this "break point" is linked to the planning standards of the network. Close to a generator, the system is designed to cater for the full output of the generator. More remotely, the system is not designed for the simultaneous operation of all generation. Generators self select according to their generating costs and their contractual position and this is supplemented by actions of the system operator balancing the system and dealing with constraints.

4.10. Traditionally, distribution system infrastructure caters for the full output of the generator and transportation to the GSP, whereas transmission infrastructure caters for specified scenarios and outage situations. Other supply/demand configurations on the transmission system are dealt with through the balancing mechanism where necessary.

4.11. We therefore believe that there should be a uniform de-minimis break point of, say 50MW, below which there would be no liability for TNUoS charges. A 50 MW limit would be consistent with the current definition of licence exemptable generators.

Removal of perverse short-run incentives

4.12. The TNUoS methodology is based on long run marginal costs of providing physical network capacity. In the short run, no additional physical capacity can be provided, but the system operator has to balance supply and demand in the most efficient way, by encouraging the most efficient generation to run to meet demand and by encouraging demand to load manage at peak times.

4.13. The current charging methodology produces negative demand charges in some areas that are inconsistent with this objective. These charges would incentivise demand to increase and generation to decrease at peak times. This is exactly the opposite signal to that being produced in the balancing mechanism. For this reason NG have adjusted the tariffs to ensure that the charges remain positive, and have consulted on a longer term solution to this problem.

4.14. However, Ofgem have now rejected this change and, as a consequence, the problem remains. We therefore believe that this underlines the need for a thorough review of all of the underlying parameters in NG's charging methodology, with particular focus on the security factor and the expansion constant which have a disproportionate effect on locational charges.

Consistent charging arrangements for generators

4.15. On the demand side, a domestic customer pays exactly the same, pro rata, for transmission capacity as a very large customer. There is less opportunity for a domestic customer to load manage, because the supply contract assumes a level of demand at the triad peak and the supplier takes the risk across the portfolio of the aggregate peak demand being in line with forecast and this needs to be addressed.

5. Proposals

Step 1- Contractual changes for GSPs

5.1. As noted above, formalising the maximum GSP export in the Bilateral connection agreement will ensure that there is adequate transmission capacity, and that increases to the required export as a result of additional embedded generation can be subjected to appropriate planning studies.

Step 2 - Charging Arrangements for Scottish 132kV system

5.2. Step 1 above would be sufficient to deal with exporting GSPs and ensure adequate transmission capacity, but other measures would be required to make charges more cost reflective and remove some of the perverse incentives.

5.3. A key anomaly is the treatment of 132kV network. In our view it would be impractical to extend the ICRP methodology into the 132kV network in E&W, since this would involve NG in obtaining cost information and assuming responsibility for 132kV charging in E&W. Instead we believe the 132kV costs in Scotland should be separated out and charged either to the DNO for inclusion as a pass through in the DNO use of system charges (this would mirror E&W) or added to supplier TNUoS as a flat sum. The latter would be the preferred option, as it would contribute to avoiding negative demand charges.

5.4. The NG ICRP model would then only apply to the supergrid of 275 and 400kV. This would remove perverse incentives to connect to E&W "distribution" rather than Scottish "transmission".

Step 3 – Transmission charging arrangements for generators connected at 132kV and below

5.5. This step would require to identify the usage made of the "supergrid" by 132kV connected generators in E&W as well as Scotland and potentially generators connected to the 33kV and lower voltage systems. It is a fact that 1MW of generation has the same effect on power flows on the transmission system irrespective of its connection voltage. On this basis it could be argued that every generator, irrespective of connection voltage, should contribute to TNUoS, as does every demand customer, irrespective of size.

5.6. This would mean that all generators paid the TNUoS capacity charge for their zone irrespective of their connection voltage, which conferred the same "right" to use the transmission system as demand customers. This would retain an "embedded benefit" for those generators in negative charging zones but this would reflect the generator charge rather than the negative of the demand charge.

5.7. Collecting the TNUoS revenue could then be split into two mechanisms. Generators choosing to contract though suppliers would pay through their contracted supplier. Generators contracting directly with NGC would pay NGC directly. It is for consideration whether there should be a deminimis value of generation which, for administrative expediency, does not pay in this way. As discussed above, we believe this should be set at 50MW.

Step 4 – transmission network management tools

5.8. The above processes would ensure firstly that adequate transmission capacity is available in normal circumstances to cater for generators' requirements. NG would normally deal with any constraints "on the day" through the Balancing Mechanism (BM). However, there may be instances where generators have opted to trade through a supplier and not participate in the BM. Although suppliers do participate in the BM, their bids are not nodal. NG would clearly need either additional information, or further contract forms to deal with this eventuality.

5.9. In our view, the simplest means would be for NG to enter into constraint contracts with generators that NG identified as being in potentially constrained areas. This would minimise the administrative burden on NG since only a small subset of embedded generators would need such a contract.

6. Conclusions

6.1. We believe the proposals outlined above would lead to more consistent charging arrangements for generators, while removing the perverse incentives are a feature of the current charging arrangements. It will also provide means for NG to manage the transmission system that are absent at present.

6.2. We therefore urge Ofgem to bring forward proposals to develop the charging and other arrangements along the lines suggested above

6.3. We would also urge Ofgem to carry out the full and thorough review of NG's charging methodology that as promised as part of the approval of the BETTA go-live tariffs.

Appendix 1 – Transmission Charging arrangements and Allocation of Transmission Capacity Rights

Introduction

It has been asserted in Ofgem's consultation on transmission charging arrangements for embedded generators that some embedded generators do not have rights to use the transmission system and do not have capacity rights on the transmission system. We believe that this is not the case and that the current arrangements do indeed grant capacity rights. However, the charging arrangements do not necessarily reflect the costs imposed.

It has been established that many Grid Supply Points (GSPs) export to the transmission system. Indeed many Scottish GSPs and related transmission infrastructure are specifically designed to permit such exports.

There are three separate but related issues:

1. Who has capacity rights on the transmission system and how are they obtained
2. The adequacy of the transmission system to cater for rights granted
3. The tools for NG to deal with lack of capacity "on the day"

Transmission Capacity "Rights"

The CUSC recognises two types of user of the transmission system: generators and suppliers. Generators are granted Transmission Entry Capacity (TEC) according to their requirements, and suppliers are granted transmission capacity according to their net forecast requirement.

Transmission connected generators contract directly with NG and their TEC is specified in the Bilateral Connection Agreement (BCA). Embedded generators either contract with a supplier or enter into a Bilateral Embedded Generator Agreement (BEGA) with National Grid (NG). If the embedded generator is "large" but unlicensed and contracts through a supplier, the relevant agreement is a "BELLA". This occurs more often in Scotland due to regional variations in the Grid Code definition of "large".

Signing onto a BEGA can be by choice, to take advantage of opportunities in the market arrangements, or mandatory because the embedded generator exceeds a certain size. In any event the BEGA establishes a direct relationship with NG and the generator obtains rights to use the system through this agreement.

Suppliers are required to forecast their requirements and NG undertakes to "transport a supply of power through the GB Transmission System to the level forecast by the User from time to time pursuant to the Data Requirements set out in Part IIB of this Section 3 submitted by that User together with such margin as NGC shall in its reasonable opinion consider necessary…" (CUSC 3.4.2)

Suppliers forecast their demand on a GSP group basis and are charged based on the triad demand net of any embedded generation. If a supplier has forecast 1000MW of customer demand NG undertakes to transport up to that level. The supplier can reduce its liability for TNUoS by contracting with an embedded generator.

The embedded generation is considered to reduce the supplier's net requirements for transmission capacity. Within a GSP group (which is the level at which supplier charges are levied), there could potentially be a number of both exporting and importing GSPs. However, the CUSC is only concerned with the net GSP group position and the supplier is only charged for demand net of embedded generation.

It is therefore clear that an individual generator's right to use the transmission system is obtained either directly from NG through a BCA or BEGA or indirectly for embedded generators through their contracted supplier.

However, this leads to generators making sizing decisions in order to avoid obligations such as TNUoS or becoming a BSC party.

This in turn leads to a number of problems: ensuring the transmission system has adequate capacity in normal conditions, and dealing with constraints in abnormal circumstances. A further issue is whether the ability of a generator to avoid TNUoS by changing the connection arrangements, size or contractual basis is cost reflective. This latter issue is the subject of the current consultation. The first two issues are dealt with below, referring to the current contractual framework.

Adequate Transmission Capacity

When a generator applies for connection to or use of the transmission system, the TO (NG in the case of applications in E&W and SPT or SHETL in Scotland) is obliged to ensure that the transmission system complies with the GBSQSS. This ensures the ability of the GB transmission system to transmit power is maintained for a number of predefined eventualities.

Connection of new generators is prevented until the necessary reinforcements are made. In E&W this obligation only comes into effect for generators over 100 MW. In the North of Scotland the limit for carrying out this analysis is 5MW. This discrepancy could lead to lack of transmission capacity in E&W (although steps are being taken to address this information mismatch).

Constraint Management Tools

To manage constraints on the transmission system, NG uses the Balancing Mechanism (BM) bids and offers to pull back generation behind a constraint. Generators participating in the BM will have their TEC granted through a BEGA or a BCA. Since TEC is granted on a nodal basis, a very targeted approach to constraint management can therefore be taken.

However, while the supplier can participate in the BM in the same way (and can respond to bids and offers by adjusting the embedded generation output) it is not clear to NG at which node the supplier may be offering to reduce generation. Therefore this tool is ineffectual in managing constraints even though it can be used for energy balancing since this requirement is non-locational.

It is possible to foresee a situation where a constraint needs to be dealt with, but the only generators available to reduce their output are contracted to suppliers, either with BELLAs or smaller generators without specific agreements with NG. In the case where NG has identified a potential need to constrain an embedded generator not party to the BSC, we believe a separate agreement should be in place.