Enduring Transmission Charging Arrangements for Distributed Generation
Response from the Association of Electricity Producers

9 December 2005

Introduction:

The Association of Electricity Producers (AEP), with a membership of around 100 companies, represents the interests of the electricity generation sector in the UK. Our members own and operate power stations and trade electricity. Their power stations use most of the technologies available and some are grid-connected, some distribution-connected. Charging arrangements for generators are one of the key commercial risk areas for our members.

The importance of distributed (embedded) generation and the interaction between distributed and transmission-connected generation was underlined by the Association's members when the first Association Policy Position on embedded generation was established in 1998. The core of this position remains valid and has been used to inform our response.

The confluence of a large variety of issue areas means now is an important time for Ofgem to consider the enduring arrangements for transmission charging for distributed generation. There is an opportunity to establish a strategic direction for development of charging arrangements that will support delivery of Government's policy aspirations and underpin continuing security of supply.

Below we make summary points and then address the issues as posed in the consultation document.

SUMMARY POINTS

- This issue area is strategically important and cannot be seen in isolation. It is connected to many other areas of government policy and regulatory review, and will directly and substantially impact on investment and operating decisions over the decade.
- We suggest that Ofgem involves Association members in the development of this area over the coming months. This will help to ensure robust paths for development are established.
- In considering the way forward we believe the following principles need to be borne in mind:
    - The industry should operate in a non-discriminatory manner for all connections whatever the voltage, whether the connection is for generation or demand and regardless of asset ownership.
    - Generation that is not centrally despatched should only be obliged to deal directly with the network to which it is connected and that network operator should have an obligation to act on behalf of the generator customer where necessary.
    - There should be a clear hierarchy of responsibility for system security that ensures that there is transparency of technical information across the DNO/NG or other network boundary.

- The security benefit that embedded generation gives to the transmission and distribution networks should be recognised in the charging methodology as well as the costs imposed on transmission and distribution.
- All network operators should be liable for the wires component of security costs in their network and also for network boundary transfers such as reactive power flow. All network operators should be required to promote an active trade in system security products with customers, generators and other network operators to optimise security and minimise cost.
- Charging arrangements provide the price for the network access product. It is imperative that the definition of this product is considered alongside any consideration of charging arrangements.

DETAILED COMMENTS

1. Why the Review is Timely
Ofgem ask 'whether chapter 3 has captured full range of interrelated subject areas?' We believe Ofgem has captured most of the interrelated subject areas but we would add a few more and have further comments on some of the areas mentioned.

1.1. Additional Areas

1.1.1. Island Generators: Her Majesty's Government (HMG) has just signalled their intention to establish a semi-permanent (up to 20 years) rebate for island generators off the coast of Scotland. We estimate this will be in place within 2-3 years and therefore spans the temporal scope of this review.

1.1.2. Definition of Transmission and Distribution: With the implementation of BETTA, HMG decided that 132kV networks would be classified differently in England and Wales (E&W) from in Scotland. As far as we are aware there are no plans to change this. Additionally, for the offshore wind farms for E&W being developed under Round 2 we understand the vast majority would need to be connected to the shore via 132kV. Depending upon the nature of the majority of the business of the network licensee that connects to the windfarm, this might result in 132kV networks that are either wholly transmission, or a sandwich of transmission and distribution. Again we know of no plans to revisit this decision area beyond the issues covered under the recent Ofgem governance consultation.

1.1.3. Distribution Network Use of System Charges (DUoS):

1.1.3.1. Location: Within Distribution Charging Implementation Steering Group Ofgem have indicated their goal of making all distributed generators liable for GDUoS from 2010. It is not yet clear how those generators who have previously paid for continuing connection and use of system via a capital payment will be dealt with although the Association has always maintained that generators connecting prior to April 2005 had paid the full amount then asked for a connection and use of system product. Also, there is no obligation on two different Distribution Network Operators (DNOs) to levy the same GDUoS on power plants that are distribution connected even if they were connected at equivalent positions in the networks. This arises for two reasons: i) DNOs do not have a licence obligation to adopt the same charging methodology as each other, and ii) all DNOs have differing charge bases and different anticipated investment in their network. Any choice by DNOs to adopt the same charging methodology would be driven by pressure for conformity from the Regulator and any cost savings arising from shared development and maintenance of the methodology. Therefore, it is by no means certain, at this point, that the longer term GDUoS will show any conformity between distribution networks.

Nevertheless, in principle a move towards more cost-reflective DUoS charging this should reduce incentives to connect at an inappropriate location on an inappropriate network.

1.1.3.2. Voltage: To date, in the development of charging methodologies for GDUoS, DNOs have indicated the difficulty of creating charging methodologies that can be applied at all connection voltages. Typically they have indicated that locationally varying cost-reflective charges can be modelled for connection at voltages of 33kV and above, but that factors such as the vast volume of data make extension of such models to lower voltages practically impossible.

Notwithstanding these issues, in principle a move towards more cost-reflective DUoS charging should improve incentives to connect at the technically correct voltage.

1.1.4. Contractual obligations: Contractual arrangements between network operators, owners and users carry a wide variety of obligations. In considering what sort of contractual forms can be used and between which parties, this needs to be borne in mind. The scale of obligations may range from provision of information to a system operator, through compliance with frequency response (and other technical) capabilities, up to commercial arrangements for access to and use of a network. This is a vast range of obligation and even within the subset of information provision there is a vast difference in the resource impact on a small distributed generator between responding to occasional ad hoc request for information, through seasonal provision of outage information, up to provision of many parameters in operational timescales. The type and timing of information required can determine whether it is necessary for a direct contact with the transmission system operator or whether indirect contact via the DNO is adequate. CAP097 and the Grid Code LEEMPS work are examples of this latter case.

The form of contractual obligations is also important as it may carry with it obligations to comply with other codes such as the contractual triangle of the CUSC, BSC and Grid Code. All the industry codes are potentially in a state of constant evolution, so there is a continuing risk to any small distributed generator bound into one code via a contractual form.

Information provision is an entirely separate issue from charging arrangements and this must be recognised.

1.1.5. Current State of Plant Stock: Within the industry there is currently a lull in new build except for certain renewable projects. A number of nuclear plants are scheduled to be decommissioned within the timescales of this review. Additionally, the governance of the network connections for offshore plant is under review. All of this means the potential for a profound change in the relative disposition of generation around the transmission and distribution networks.

1.1.6. European Harmonization: Over the course of the last year the European strategy for harmonization of the G/D ratio for TNUoS with a long term goal of the European norm of 0/100 has changed to a desire that the G/D ratios should not diverge any further. It is not clear whether the earlier goal will be reinstated, or separate development will prevail in the longer term.

1.1.7. Planning Standards and Wind farms: There are currently two academic studies in train that are considering how the current planning standard rules could be amended could be amended to take better account of the presence of large amounts of wind generation in particular regions of the country. Both these studies should come to fruition by early 2006. Their results could feed directly into transmission charging methodologies. In this context it should be noted that the recently released report from Environmental Change Institute for DTI essentially concluded that wind powered generation is more nearly like other forms of generation in terms of its annual load factor and its seasonal correlation of output with demand. This might be seen as an argument for no or less special treatment for wind.

1.1.8. CONCLUSION The factors identified by Ofgem and the additional issues raised above suggest the following:

- The situation already has contradictory and crossed elements
- Many of those elements are outside the remit of this review
- Many of those elements have already been in place for a long time and/or will be in place for a long time
- Therefore any radical change must have a substantial benefit if it is to outweigh the costs of disruption and change.
- There can be no perfect ‘economics’ answer because some of the ‘distortions’ are the result of government policy, but the do nothing option is not obviously the correct one.
- Therefore a sensible goal is to limit gross disharmonies, and establish strategic criteria that can inform future changes and thereby allow parties to make informed guesses as to how a rational regulator would respond to future proposals for change

2. Issues to Be Addressed: In Chapter 4 Ofgem discusses the issues to be addressed and seeks comments on them and any further issues that need to be addressed. Below we make comment on those issues raised.

2.1. Exporting GSPs Without Access Rights:

2.1.1. NG operational concerns: We believe that NG’s operational concerns have some merit but are overplayed. It is sensible for an orderly set of connected networks that the transmission SO has some knowledge of generation above some de minimus level and ultimately to be able to control of flows onto or off transmission system. They also need to know about net volumes for constraint management. However, there is no need for any change in charging arrangements if information provision is the primary concern.
It seems to us that ancillary services are unlikely to be major issue unless an exporting generator is operating with a very unusual power factor affecting reactive power, but the DNO should be managing that anyway. The effect on frequency is directly related to output and its rate of change and therefore should be captured under gross volume of energy issue above. Therefore except in unusual circumstances, it seems unlikely that additional BSUoS costs will be a major issue.

2.1.2. Commercial issues: We believe this is a much more important issue. The big issue is cost allocation and free riding. This is relevant in terms of the effect on both TNUoS allocation and BSUoS allocation. Feedback effects in the cost allocation will tend to enhance any perverse incentive to connect on distribution network. Please note that in those areas of grid where generation TNUoS is negative, exporting gsps may provide system support. The issue here is that such adventitious support may be of little value if the SO has no prior knowledge of its timing and magnitude.

2.1.3. GSPs or GSP Groups: NG has made great play of unanticipated export from individual gsps. For a distributed generator, the pattern of flows within a DNO network and hence the balance of export within a gsp group is under the control of the DNO. The important commercial issue: ‘how to deal with distributed generation that may under certain circumstances lead to exports at some gsps’, is better dealt with by a consideration of the export across the gsp group.

2.2. Perverse Incentives Voltage: We accept that if a generator chooses to connect at a technically sub-optimal voltage in order to minimize their anticipated connection and use of system charges, this may have the effect of causing other costs across the network. However, if a generator connects at a technically correct voltage and thereby is distribution connected, that is likely to have the effect of reducing net import into the DNO system and may mean that transmission assets thereby become oversized for normal operation. The example adduced by Ofgem in this section does not clarify this difference.

2.3. Perverse Incentives Size: Ofgem correctly point out the arbitrary nature of the definitions of Small, Medium and Large. It should also be noted that the thresholds for licence exemption are arbitrary. From these arbitrary definitions a number of arbitrage opportunities arise for generators. Nevertheless, it seems unlikely that a more robustly defensible alternative would easily be available and these arbitrary definitions have influenced a substantial amount of development to date. Therefore the costs and uncertainties associated with replacing these classifications would need to be significantly outweighed by the benefits.

We understand that the current regional definitions of Small, Medium and Large arose from a consideration of the inter-regional power transfers under the British Grid System Agreement and the consequential information and control requirements. When the current work underway under the aegis of the Grid Code comes to fruition in the spring, it should be possible to gauge what the costs and benefits of change would be.

2.4. Interaction with Current GB Access Queue: We accept that the interaction with the current queue needs careful consideration.

2.5. Trade offs: we have already indicated in section 1.1.8 that a number of drivers lead to the requirement for pragmatic trade-offs. In seeking to achieve such trade-offs a number of practical criteria can help beyond the normal licence issues of facilitating competition and ensuring efficient operation and development of the system. These are:

- Equitable allocation of charges: The industry should operate in a non-discriminatory manner for all connections whatever the voltage, whether the connection is for generation or demand and regardless of asset ownership.
- Recognition of Benefits: The security benefit that embedded generation gives to the transmission and distribution networks should be recognised in the charging methodology as well as the costs imposed on transmission and distribution.
- Charges should encourage connection at ‘technically’ correct voltage
- Simplicity of Interfaces: Generation that is not centrally despatched should only be obliged to deal directly with the network to which it is connected and that network operator should have an obligation to act on behalf of the generator customer where necessary.
- Clarity of Network Operators’ Obligations: All network operators should be liable for the wires component of security costs in their network and also for network boundary transfers such as reactive power flow. All network operators should be required to promote an active trade in system security products with customers, generators and other network operators to optimise security and minimise cost
- Long-Term Clarity: The usefulness of strategic regulatory clarity in an industry with project life cycles of twenty years or more:
    - A stable basis for charging
    - A well-signalled programme of change
    - Account being taken of the interaction in timing between distribution and transmission charges within a holistic framework

3. Options for an Enduring Charging Framework: Ofgem have presented a number of possible options and we comment on each in turn. In general, a number of the options

seek to redraw the commercial boundary between the transmission system operator and the distribution system operator; they do not address the issue of how to deal with the flow across the boundary. It needs to be recognised that such re-drawing is unlikely to provide strategically robust answers.

3.1. Do Nothing: We accept that a do-nothing approach would fail to improve the cost reflectivity of charging arrangements relating to distributed generation. However the case for change needs to be robust. Also, the list of issues in Chapter three together with the additional issues set out in Section 1.1 strongly suggests that change needs to be considered now.

3.2. De-Energise plant that spills: We do not believe that this option is practicable.

3.3. Amendments to the Charging Model: We accept that changes/refinements to the charging model will not address the issues highlighted in Section 2 above.

3.4. Extend the DCLF ICRP model to parts of the distribution network: DNOs have already indicated that they would look to develop locationally varying charging methodologies down to 33kV. Therefore any such extension would need to consider this voltage as well. Additionally, each DNO would have a cost-recovery requirement as well as a locationally varying charge. Therefore, the degree of conformity in charging achieved across the connected networks would only be partial anyway. There would also be the continuing issue of charging for access at the lower voltages and the discontinuity in charging, but this is probably insoluble. Therefore, whilst a common approach to charging methodology would be attractive from the perspective of transparency, it is unlikely to result in equivalence in charging.

Therefore whilst a degree of harmonisation between locational signals for connection and use of system might be obtained, it should be recognised that this would only be partial. Also, the change in charging arrangements would not address the access issue.

3.5. Amend use of Size Definitions as the basis for charging and contractual arrangements: Amending the size definitions so that more generators would have to sign BEGAs would have little intrinsic merit, merely add to their administrative burden. However, a consideration of a threshold above which a generator will have an impact on the transmission network would be part of a move towards a more equitable allocation of costs between those that make use of the transmission and distribution systems. However, it should be noted that in principle a gsp could become exporting if there was a sufficient number of domestic microchps attached below the gsp. 25 million CUSC BEGAs or BELLAs does not seem an outcome that anyone would welcome. Therefore definition of such a threshold would be practically very difficult, as it is the aggregate of demand and generation on a distribution network that determines the effect on the transmission network. It may be the case that Government policy would create a de minimus via its support for particular technologies. Over all this option may need further consideration, but it is not obvious how it could be made to work.

3.6. Creating a Consistent Liability for Charges: Currently demand TNUoS is set on a gsp group basis, whereas GTNUoS is set on a zonal basis determined by iso-charging contours. The disruption to supplier charging would be considerable and have wide impacts. If generation zones were dragooned into gsp groups, there would be inequitable charging. If a nodal approach were adopted, this begs the question of which node within a gsp group is a distributed generator attached to? At the moment

DTNUoS is constrained not to be negative, because of the possible impact on demand at times of system stress. Would this continue to be the case?

3.7. Agency Models: Agency models specifically involving a role for Suppliers or the DNOs as ‘exit access managers’ were discussed in the Transmission Access Standing Group (October 2003 Sections 9 & 10)). Their role with regard to distributed generation would be a part of this total role. The role would encompass access rights onto (and off) the transmission network. There is the linked problem of how generator access rights and ‘excess access’ to the distribution network are defined and valued. The definition of TEC for the transmission network was deliberately limited to entry by generators and has not yet been extended to exit by Suppliers. This is due, at least in part, to the difficulty of defining the demand-side access product, particularly for NHH demand. Therefore the effort required to develop the agency approach should not be underestimated. The role of agency would need to be seen together with amendments to charging arrangements that might take account of one of the options above.

Both of these routes have issues associated with them and are likely to incur substantial cost in their implementation. Neither of these two routes is easy. Nevertheless, they are worthy of further assessment. This assessment must involve affected industry parties.

3.7.1. Supplier as Agent: Suppliers already have contractual relationships with the DNO and the unlicensed embedded generation. Nevertheless, if there are a variety of suppliers and generators below the gsp, there is still an issue about how access is allocated between suppliers. If unresolved this would lead to an inequitable allocation of costs. Supplier access to the transmission system is the net of HH offtake, NHH offtake and export; definition and more importantly accounting for these components of access volume will be difficult.

3.7.2. DNO as Agent: This option will require the DNO to manage access risk across his region. DNOs are not currently equipped to manage this process, nor do they have income and/or incentive schemes to encourage them to undertake this role. Alongside any additional access management, there will still remain the contractual relationships between suppliers, DNOs and generators. Also, if the supplier is operating its demand and distributed generation as a portfolio, there is scope for confusion and complexity for the DNO, in managing access between a number of suppliers in one DNO region.