CE Electric UK

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Dear Colin

RESPONSE TO ENDURING TRANSMISSION CHARGING ARRRANGEMENTS FOR DISTRIBUTED GENERATION DISCUSSION DOCUMENT

I am writing on behalf of CE Electric UK Funding Company (CE), which is the UK parent company of Northern Electric Distribution Ltd (NEDL) and Yorkshire Electricity Distribution plc (YEDL).

We welcome this discussion document, and agree with Ofgem that the best solution would be for industry players to bring forward changes to the various framework documents to address the issues raised.

The attached document is CE's response to the above consultation.

We look forward to publication of Ofgem's summary of responses in the new year, as we believe some of the issues are too broad to be addressed in a single document and expect that this follow-up document will stimulate the requisite broader debate.

Should you have any queries, please contact me on the above number.

Yours sincerely

Joseph Hart
Network Sales Manager

Enduring transmission charging arrangements for distributed generation – Ofgem discussion document September 2005

Summary

We welcome this discussion document, and agree with Ofgem that the best solution would be for industry players to bring forward (and, ideally, agree) changes to the various framework documents to address the issues raised. We believe that Ofgem will need to take a stronger lead, as some of the issues are too broad to be addressed in a single document and there appears to be marked differences in philosophy between, in particular, NGET and other key stakeholders.

We also believe that Ofgem must take a strong lead in determining the principles on which embedded generation can gain access to both the distribution and transmission systems, and the basis of transmission charges for connection and transportation.

We also submit that this debate must consider how access to the network will be gained, as well as how that access will be charged for. When considering charging, the key issue is not whether embedded exemptible plant bears a 'fair' share of the TNUoS bill, but whether the transmission system would be developed more effectively if TNUoS liabilities were incurred by more generators than is currently the case.

Specifically, we recommend an approach where:

- the bi-directional nature of distribution networks is explicitly recognised in CUSC etc.;
- reinforcement of the transmission network is managed by NGET on the basis of user forecasts and funded through TNUoS, and not predicated on specific modification/connection applications, underwritten by individual developers;
- energisation of exemptible embedded generating plant is made contingent on transmission reinforcement works only in extreme circumstances, with the clear presumption that any such plant may be connected;
- distributors have a responsibility to bring forward Modification Applications where customer connections, whether individually or in aggregate, may breach fault level or power flow capability at GSPs;
- licensable plant requires firm access rights through TEC and incurs a TNUoS liability; and
- embedded exemptible plant does not require a firm access right, but a TNUoS liability is incurred for all half-hourly metered sites and borne by suppliers.

Having reviewed the options suggested by Ofgem we feel in general that those suggesting changes to the connection boundaries would simply serve to move the issues downwards rather than resolve them. Whilst others such as the application of the DCLF model to distribution networks and the introduction of an Independent Distribution System Operator would add greater complexity and be potentially very costly to implement. We would support the “do nothing” option or the “supplier agency model” as suppliers currently have a liability for demand TNUoS charges, so it would not be unduly complex to develop the existing charging interface to include a liability for generation TNUoS charges as well.

Ultimately if DNOs are faced with additional transmission costs they will need to pass these on. To simply shift the levying of charges from NGET to DNOs or to the IDSO would not necessarily be the right option for consumers.

The issue is not just about transmission charging, but about the fundamental ability to gain access to the total system.

General Comments

CE Electric is actively involved in a number of the interrelated areas identified by Ofgem and we are happy to contribute to the debate. There is undoubtedly a need to define the real issues which the industry as a whole is seeking to address, primarily the efficient development and operation of both the transmission and distribution systems and the promotion of competition in the generation and supply of electricity.

We believe that it would facilitate the debate if Ofgem were to lay out the key principles such as:

- the desired degree of consistency between generation and demand;
- which generators are deemed to ‘use’ the transmission system;
- whether the efficient development of the transmission system would be better served by levying charges in respect of embedded exemptible generation plant;
- if so, for what size of plant any charges should commence, and on whom they should be levied;
- whether the connection of embedded exemptible plant is deemed to have sufficient impact on the transmission system to require connection to be deferred pending transmission reinforcement;
- if so, to what size of plant such restrictions should apply (and, if the concern should be over cumulative impact, whether the industry should seek to address this issue rather than penalise individual developments), and who should bear any costs (including under-writing liabilities);and

- whether some form of capacity trading might result in a more equitable treatment of new generation and lead to more efficient development of the transmission network.

WE accept that there are fundamental differences between transmission and distribution. The transmission network is a meshed, high-redundancy system optimised for mass, long-distance power flow, whilst the distribution networks have less redundancy, and hence an inability to influence power flows as they are optimised for short-haul. Furthermore, distribution networks have millions, rather than hundreds, of nodes. It may therefore be entirely appropriate to have different commercial arrangements to facilitate the economic development of the two types of system.

Over recent years suppliers and end-users have been subject to many changes in both the transmission and distribution arenas. Changes in connection boundaries have resulted, in some instances, particularly for transmission, in a shift in charges between connection and use of system within short timescales, not always providing the suppliers/generators/end-users with sufficient time to quantify the impact on them.

In the distribution arena the structure of charges debate is still looking at the development of an enduring solution following the introduction of a shallower connection boundary in 2005 and the application of generator use of system charges applying to new generation connections after 2005. We understand that Ofgem will shortly publish conclusions on these topics, with the intention of providing a platform for the development of longer-term and enduring charging arrangements by the DNOs and the industry. DNOs are working together with other key industry stakeholders to agree a common approach and will put forward proposals in accordance with the methodology modification process.

Taking all of these issues into account, it is essential that any debate, when considering the need for consistency between demand and generation, considers the impact of these changes on market participants, the parameters of any agreed timescales and the ease of implementation.

Interrelated areas of work

Ofgem has identified many areas of interrelated activity, multiple work streams are ongoing and we are actively involved in the following areas:

- structure of distribution charges review (SoC);
- a series of proposed CUSC amendments, such CAP 093 & CAP 097; and
- a Grid Code Review Panel working group to review the regional differences triggered by the definition of small, medium and large power stations.

We are also aware of the other relevant areas such as;

- different voltage definitions of transmission in England & Wales compared with Scotland;

- the interim discount granted to small generators in Scotland for a maximum of 3 years; and
- the Authority's conditional approval of NGET's GB use of system charging methodology.

We offer some general comments and then discuss each of the options suggested by Ofgem in more detail.

We recognise there is a need to review the GB-wide electricity market further following the introduction of BETTA. Under BETTA Scottish generators now have easier access to the larger demand for electricity in England and Wales. Scotland already has surplus capacity and there are plans to more than double the amount of renewable generation. The knock-on effect of this, however, is that the transmission network in the north of England is already near full capacity and significant investment will be required to accommodate such a high level of generation. This is in addition to the higher levels of embedded generation expected to connect to distribution networks.

NGET have stated that, as a result of the Government's Renewables Obligation (RO) providing strong incentives to develop new renewable generation projects, a step-change has been created in demand for connections to both transmission and distribution networks, in NGET's view leading to a larger number of GSPs exporting onto the transmission system.

The analysis carried out by the CAP 093[1] working group showed that in England and Wales there are currently only a few "spilling" sites. With around a dozen at system peak and less than two dozen in the summer trough (on average 20-30MW per site) it is not considered to be a current major problem. It is, however, anticipated that there will be an increasing requirement for two-way flow between the transmission system and distribution systems. The amendment proposal is designed to allow licensed distributors to continue to meet their obligations to provide connections for both demand and generation.

CE was represented on the working group and raised the Working Group Alternative Amendment (WGAA), which we believe recognises the bi-directional nature of the distribution systems and GSPs. The original CUSC amendment and the WGAA seek to correct a defect in CUSC that apparently prevents GSPs from facilitating the flow of electricity from distribution systems to the transmission system.

We believe that the revised definitions better facilitate effective competition in the generation and supply of electricity and that this amendment should not be deferred pending the outcome of further consultation, as it effectively denies embedded generators the right to connect until that process is complete. We believe that NGET are utilising this amendment proposal to raise charging issues which were specifically excluded from the scope of the working group, but which are entirely legitimate issues for this Ofgem discussion paper.

[1] CAP 093 – Enabling the Flow of Electricity form Distribution Systems into t he Transmission System at Grid Supply Points.

We have also been actively involved in the CAP 097[2] process and we believe that NGET's proposals are disproportionate and are potentially a barrier to small and medium generators connecting to distribution networks. The proposed amendment links the initiation of reinforcement works, with consequential financial liabilities, to the connection of a single generator perhaps as small as 30MW, rendering such investments inefficient.

NGET claim that transmission reinforcement cannot be carried out efficiently without forcing such generators to under-write the works involved. However, they acknowledge that such a development in isolation will not impact on the MITS. Their approach seems to us less likely to bring forward timely and efficient investment than one based upon distributors' forecasts, or one based upon the assumption of meeting government targets for renewable generation.

The WGAA provides NGET with the information they need to develop an economic, co-ordinated system where bulk capacity is provided according to the aggregate of customer needs and not the unfortunate party deemed to be the trigger for transmission reinforcement. We believe that the proposed amendment will distort competition in generation by placing undue costs upon developers of embedded projects.

Following implementation of BETTA, Ofgem introduced a new licence condition for NGET, a rebate for small (less than 100MW) transmission-connected generators to address a specific arbitrary benefit to being distribution-connected in England and Wales as opposed to being transmission-connected in Scotland. The discount was only set for a period of three years with a view to reviewing the charging arrangements and developing enduring arrangements for charging distributed generators. This has the effect of subsidising these generators, with the shortfall in income recovery being made up by demand customers.

It has been suggested that the differential charging arrangements for distribution-connected and transmission-connected generators can lead to perverse incentives when deciding where, and at which voltage, to connect. It is not proven that, in offsetting GSP demand, the distributed generator would give rise to transmission system costs for which it would not be liable. In fact it is possible that it could offset the need for reinforcement on the transmission network.

1 Options for an enduring framework for distributed generation

We have reviewed the options suggested by Ofgem and have the following comments:

Option 1: Do nothing

We recognise that the "do nothing" approach would not provide an enduring solution to the issue of the rebate for small generators connected to the 132kV transmission network in Scotland. However, parties currently liable for TNUoS charges would continue to be so, with charges calculated in accordance with the use of system charging methodology, and there would be minimal impact on existing arrangements.

[2] CAP 097 Revision to the contractual requirements for Small and Medium Embedded Power Stations under CUSC 6.5

There is some merit in this approach for charging issues, although the ability for embedded exemptible plant to gain access to the transmission system requires some work (for example, by approving the CE WGAAs for CAP 093 and 097). The case has not yet been proven that the transmission system would be developed more efficiently if TNUoS liabilities were incurred by more generators than at present.

We note that there are differences between Scotland and England. However, it is not practical as Ofgem suggest in section 4.9 to connect to NEDL's distribution network rather than to Scottish Power's transmission system, simply to avoid TNUoS charges, as the nearest 132kV bar is over 50 km from the operational border. If voltage were an issue, it should be noted that half of CE Electric's GSPs transform down to voltages other than 132kV - distortions which would remain unless the boundary moved down to 33kV. Even then, it would simply move the problems downwards, as developers might seek 'large 11 kV' connections rather than 'small 33kV' connections.

Option 2: De-energise plant that spills

In view of the fact that the studies carried out concluded that the number of GSPs that currently spill are few in number it would seem both a draconian and disproportionate measure to de-energise such plant and would no doubt create more issues than it sought to address. We agree with Ofgem that it might not be considered appropriate to prevent a plant from generating because of what could be a relatively small export onto the transmission network, which might be caused largely by circumstances beyond their control.

Option 3: Amendments to the charging model

This option seems only to address Scottish 132kV issues. However, as Ofgem have stated in the absence of changes to charging thresholds, amendments to NGET's charging model would not extend the liability for charges but rather would only serve to change the allocation of charges between existing paying parties.

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

Applying a single charging regime for transmission and part of distribution might remove the Scottish 132kV issue, but would create similar issues elsewhere. For example, as previously noted, half of CE's GSPs transform down to voltages other than 132kV. This option would, therefore, extend the issue of arbitrary discrimination by voltage in the north-east and Yorkshire down to the 66 and 33kV systems. This would spread the issue over a wider area and simply move the issue downwards, through to lower voltage levels. It implies that generators connected below the new boundary continue to ride free.

The wholesale transfer of the 132kV systems to NGET, whether operational of ownership, would represent a major step, one that we would resist. It would involve the re-assessment of the distribution price controls, re-definition of settlement boundaries and re-valuation of distribution businesses. Given the scale of these changes this does not feel like a credible solution at this time. Furthermore, again the boundary issues would simply be moved downwards, increasing the discrimination by voltage of connection in North-East and Yorkshire

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

Moving the boundary through the Grid Code assumes there is already a bilateral agreement with NGET. The same issues would again simply be forced downwards through to lower voltage levels and occur around different thresholds. This option does however provide scope for proportionate solution, for example, moving TEC/TNUoS requirements down to 30 MW.

This approach would also involve extending the area of influence of NGET to a larger number of parties, which is likely to impose a greater administrative burden on both distributed generators and NGET.

There may also be the likelihood of the need for a new billing system unless aligned with existing boundaries.

The only way to avoid undue discrimination on grounds of voltage or geography is to remove both as limiting conditions, and instead create liability based upon size. Allowing small, medium and large embedded stations a “free ride” may not in fact distort development of the transmission system but may be the best way to promote completion in generation through encouraging market entry.

Option 6: Creating a consistent liability for charges

If all parties faced a purely locational charge, based on the long run marginal cost of locating at a given point, this would ensure that users or classes of users are not being discriminated against. It could be considered that an additional MW of generation, regardless of the voltage of connection, imposes the same costs on the transmission system; by increasing flows or reducing off-take, signalling the cost or benefit associated with locating at that point.

This would address the issue of parties connected to 132kV in Scotland and render the discount provision obsolete and would seem to address the distortions between transmission and distribution connected generators, ultimately facilitating competition.

This option would require changes to CUSC and NGET’s charging methodology. However, it might readily be accommodated with minor modifications to existing billing processes.

Option 7: Agency models

Firstly, it is important to note that an agency model is predicated on agreement over which generators are required to be costed for the efficient development of the transmission system. Once we have established which sites incur a liability, we can discuss on whom that liability falls.

However, the debate over agency models serves to illuminate the debate over underlying liabilities, as it demonstrates practical solutions to the issue.

A supplier agency model would introduce consistency with demand charging, and the option outlined in 5.42 would require only minor modifications to SVA, so long as the charging boundaries are aligned. Suppliers currently have a liability for demand TNUoS charges based on their off-take over the Triad derived from half-hourly demand metering, so it would not be overly complex to develop the existing charging interface to also include a liability for generation TNUoS charges.

This would involve a two-tier charging system, with a conventional TEC privilege and TNUoS liability for licensable plant on one hand, and a more diffuse TNUoS liability (likely without an explicit access right) for embedded exemptible plant.

This may involve changes in the way accounts are produced, i.e. charging a supplier demand charges based on their demand off take and generation charges based on their total metered volume of distributed generation, rather than netting off the two as at present. Such an approach would recognise the impact that each incremental or decremental MW of generation has on flows on the transmission network and hence reflect such costs.

Implementing a DNO model would place an administrative burden on the DNO who currently has no incentive to operate in such a capacity. It would be wholly inappropriate for distributors to participate in such markets, given their licence obligation to offer terms for providing and maintaining connection, this could be seen as a conflict of interest.

The introduction of an Independent Distribution System Operator (IDSO) would be administratively complex and would require changes to multiple codes, licences and legislation. It is far from clear what the conflict of interest mentioned in 5.49 actually is. This option is probably only practicable in the long term, if ever. Whilst it might seem an appropriate development as distribution networks require more active management, in practice this change will most likely be phased in randomly over time.

Capacity auctions

One option not discussed in the Ofgem paper is a market for transmission capacity. If our proposals for free access for embedded exemptible plant are taken, up this may not be an issue. However, we currently see new, green generation being delayed in connecting to the Total System while existing, largely fossil-fuel powered, generation sits on legacy capacity.

If the link between embedded exemptible plant and transmission reinforcement is proven to the degree that it is clear that some connections will have to be deferred pending NGET works, it may be more efficient overall to create a capacity market. It would at least be helpful to understand how much exiting generators value their current access rights.

Any such market would have to deal in relatively small blocks of capacity, to allow embedded plant to compete meaningfully with directly-connected stations.

Conclusions

Having reviewed the options suggested by Ofgem we feel in general that those that suggest changes to the connection boundaries simply serve to move the issue downwards, whilst others such as the application of the DCLF model to distribution networks and the introduction of an IDSO add greater complexity and will be potentially very costly to implement. We would support the “Do nothing” option or the “Supplier agency model” as suppliers currently have a liability for demand TNUoS charges, so it would not be overly complex to develop the existing charging interface to also include a liability for generation TNUoS charges.

It should be noted that half of CE’s GSPs transform down to voltages other than 132kV, with most of these being evenly split between 66 and 33kV. These are spread across our service areas, so bringing 132kV into line with 275 and 400kV would simply raise the same issues as between 132 kV on the one hand and 66 and 33kV on the other.

Ultimately if DNOs are faced with additional transmission cost they will need to pass these on. To simply shift the levying of charges from NGET to DNOs or IDSO and would not necessarily be the right option for consumers.