Industry responses

Charging pre consultation GB ECM 14: Consequential impact of CUSC amendment proposals CAP161 to 164

December 2008

1.0 Purpose

This document contains the responses that National Grid has received from Industry participants with respect to GB ECM 14. The table below show the respondents along with the main issues raised, Annex 1 contains the responses. National Grid will discuss the issues raised and the next steps at 22nd December 2008 TCMF.

Company	Summary
Welsh Power	SO incentives are an important issue in SO Release, National Grid requires a strong incentive / exposure to forecast accurately. Charging methodology for overrun must be transparent. Further understanding for including of non-Balancing Mechanism activity within the pricing required e.g. Warming, Intertrips, and PGBTs
British Energy	CAP161 - Impact on BSUoS could be minimised through appropriate SO incentives. CAP162 – support simple methodology that should be kept under review, do not support Marginal methodology. CAP163 – If TNUoS is recovered from the donor party then agree no additional charge on recipient (subject to appropriate mechanisms for local and residual charging). CAP164 – support for more cost reflective approach than the original. Do not support TNUoS based charge being passed through BSUoS.
EDF	We expect the planning and operational standards to ensure that the overall costs incurred both in the long and short run are acceptable. The structure of charges should reflect how costs are incurred, so fixed investment costs and marginal operating costs should be charged as fixed and variable costs Cost-reflective charges should relate to either the long-run investment costs of the system or the short-run operational costs of the system. We rely on NGET's charging in order to ensure charges are cost reflective, fair and provide no significant perverse incentives. We allow for reasonable approximations in order for simplification and believe current TNUoS charging strikes the right balance between cost reflectivity and simplicity.
SSE	Support a charging regime as follows: Generator only local assets For those transmission assets used solely by generation user(s), a user-specific charge that reflects the upfront capital cost and ongoing maintenance cost of those local assets. Wider shared transmission assets For the parts of the transmission system used by both generation and demand users, a uniform commodity charge that is levied on generation users based on their measured export onto the transmission system. Concerned that short term users are not liable for wider TNUoS charges and the possible long term implications for transmission investment.
SP	Complexity in the framework and charges will reduce the take up of TAR related products. A uniform transmission charge levied on all generation on a half-hourly metered basis would better facilitate competition. The predictability of charge affects the 'bankability' of projects.

RWE	CAP164, connect and manage, a cost reflective charge should be introduced. Support for the marginal overrun model. Further consideration is required of the impact on revenue recovery and the predictability of the residual charge.
BIFFA	SO incentives should afford protection to BSUoS parties. The cost recovery model is preferable, leaving other player neutral.
E.ON UK	Whilst short term products provide additional flexibility, they will generally be secondary to long term access products. The volume of short term products is likely to be relatively low and so simple arrangements for both SO release and overrun charging are appropriate.
REA	The marginal charges based on the transport model should not be charged for access products that do not precipitate transmission investment or provide wider rights to a generator. All generators should face local network charges. Should consider use of additional TNUoS contribution under CAP164 cover increased BSUoS costs.

National Grid initial thoughts on issues raised and way forward

This section provides National Grid initial response to the issues raised in the responses.

Non Balancing Mechanism costs

The construction of the tariff includes activities that are undertaken other than Balancing Mechanism activities to ensure that all the costs imposed by overrunning are taken account of in the constriction of the tariff. In most cases this will decrease the cost of overrunning.

National Grid will choose to carry out a certain percentage of actions prior to Balancing Mechanism through Pre Gate Balancing Trades. These are taken outside the Balancing Mechanism, consistent with the Balancing Principles Statement, on the basis that they are forecast to provide a more economic solution.

In the case of Intertrip, whilst no MW reduction is delivered there is still a cost associated with switching the Intertrip in to facilitate higher pre fault transfers. In deciding whether to accept theses costs National Grid compares them to the cost of constraining an equivalent volume. So as the intertrip costs are a replacement for constraining plant off these should be included in the tariff model.

Overrunning parties may ‘sterilise headroom’, i.e. they prevent National Grid from accessing reserves in part of the network, requiring National Grid to create reserves on the system. Given the difference in the lead time for calling non synchronised plant and gate closure, National Grid needs to warm plant to ensure it is available to run within gate closure timescales, also possibly due to uncertainty over overrun. Where these costs are direct as a result of plant overrunning it is considered appropriate that they contribute directly, and therefore they would be included in the tariff calculation.

Role of incentives

National Grid agrees with the respondents who believe that SO incentives are critical to the effective and efficient functioning of these products. In the pre consultation National Grid indicated that it would work with Ofgem and the industry to developed appropriate incentives. National Grid intends to discuss with Ofgem the exact process for developing these new incentives and the interaction with existing incentives. The aim is to have appropriate arrangements in place by 1st April 2010. The consultation process for these is likely to involve a number of industry seminars and consultations during 2009.

Transparency of SO Release process
National Grid understands the concerns expressed in relation to transparency of the SO release process. National Grid agrees that the SO Release methodology should be an Industry document (where CUSC parties can raise change requests) and that all auction bidding information should be published.

Nodal Settlement and Zonal Tariff
Some respondents indicated that it was confusing what the role of zones would be in a nodal model. Under the existing long term model, TEC is allocated on a nodal basis, although the charge is defined on a zonal basis (all nodes within a zone are subject to the same tariff). The WGAA for Overrun proposes to maintain this arrangement for overrun charging. The Overrun tariff would be set based on the average cost across a zone with the charge being set by the nodal metered output.

Preferred charging model for Overrun
The majority of respondents favoured a simple model, however there was some support expressed for both the cost recovery and marginal models. Generally the view was that the simple model provided a reasonably close approximation to an ex ante prices, yet retained some protection for third parties. Most respondents indicated that the simple model was a proportionate response given the expected low volumes of overrun. Some respondents also expressed that development of a more complex model would reduce transparency and predictability, increasing the risk and therefore discouraging the use of overrun.

Considering the support for the Simple model as a default and as a primary mechanism National Grid intends to develop this further for discussion at TCMF.

National Grid believes that a marginal model would provide the most economic and efficient short term signal consistent with providing efficient long term investment. However, a marginal model could not be implemented by April 2010. National Grid recognises that there are a number of implementation, development and cost benefit issues that need to be addressed in relation to the marginal model. Similar to the Balancing and Settlement process there may also be some benefit in discussing slightly more predictable models where the outlying costs are averaged ('chunky marginal'), encouraging the efficient use of overrun but providing protection for other users.

Development of a marginal model
Respondents raised some concerns about the stage of development and complexity of a marginal model, as well as more fundamental concerns, such as the robustness when applied to generation only and proportionality considering the likely implementation costs.

National Grid appreciates the concerns expressed about the stage of development and complexity. National Grid agrees that there would need to be a period of testing and trialling before go live to ensure that the model performed as expected. Given the magnitude of the project the Industry would need an effective change control mechanism to manage final implementation. National Grid believes that the current amendment mechanisms to the CUSC and charging and are reasonably flexible that they can deal with changes to implementation dates or issues raised during detailed development of a model.

During assessment National Grid made available a reasonably complex model that calculates the long term price (replicating the transport model) along with the locational marginal price. National Grid also produced a number of scenarios that investigated differing aspects of a marginal model e.g. varying the location of the hub. This model reasonably demonstrates the main principles involved in calculating the overrun price based on a marginal principle. National Grid appreciates the limitations of this model and the desire from users to see more detailed tariffs from a scaled up model.

National Grid intends to work with TCMF and CISG to address these concerns. National Grid could produce marginal prices ex post based on bids and offers, but without significant development work would be unable construct a reasonably robust platform to produce real time marginal prices taking full account of constraint interaction. With the TCMF and Ofgem National Grid will investigate further the cost benefit case for the development of a marginal model.

RCRC
The model developed and presented in the pre consultation for Simple pricing of Overrun includes indexation against BSUoS-RCRC. The element of RCRC was included as it provided the best correlation to constraint data. A respondent highlighted a number of concerns with including the RCRC element in the calculation. There are also a number of timing issues relating to when accurate RCRC data become available that National Grid is currently investigating. National Grid will discuss these issues with TCMF before deciding the way forward.

Volume or Settlement period weighting
All of the respondents who commented on this area indicated a preference for volume weighting. Given that the proposed charge will be on volume basis National Grid agrees with this view and intends to develop the simple model based on volume weighting.

ANNEX 1 – RESPONSES

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14 November 2008

Dear Patrick

GB ECM - 14: Consequential impact of CUSC amendment proposals CAP161 to CAP164

Welsh Power welcomes the opportunity to comment on this charging pre-consultation document. As the owners of an existing coal fired plant, Uskmouth Power, and the developers of a new CCGT power station, Severn Power, Welsh Power believes that transmission access is vital to securing the GB electricity market in both the short and longer term. It is crucial to ensure that the appropriate charging methodology is developed for these new products i.e. entry overrun and CLDTEC.

Welsh Power believes additional SO incentives are required with the introduction of the CLDTEC product in comparison to the 5 week ahead and 2 day ahead SO release products. These two shorter term product options are less risky due to National Grid having greater certainly of the increased constraint costs closer to real time, unlike the CLDTEC product. As a consequence of CLDTEC being available for up to 45 weeks ahead, there is a greater probability of inaccuracies with National Grid's forecasting of constraints. We would like to propose that CLDTEC should only be progressed if the SO is exposed to 80% of the forecast error cost that incurs as a result of National Grid's inaccuracies of forecasting constraints. This type of incentive is vital to ensure the SO makes every possible effort to accurately forecast constraints limiting the amount of cross subsidiary arising from users of CLDTEC and other NTS users via the BSUoS charges they face.

With regards to entry overrun, we believe any overrun cost methodology needs to ensure that users have the ability to forecast the likely cost of overrunning in order for the tool to be considered for use. A generator maybe willing to participate in the Balancing Mechanism (BM) without the required level of entry capacity holdings if it had the means to factor in the overrun price to its offer price. Users need to be able to assess the risk and reward opportunities available from the new overrun product.

The simple and cost recovery charging methodology options both contain subjectivity being applied by the SO. Welsh Power would like to propose a detailed methodology being published, providing transparency of the process undertaken by the SO for the degutting of trades. This may address the industry's concern of these charging methodologies currently containing a black box process. It would be helpful for a draft of the subjectivity of trades' process methodology to be made available soon in order to accurately reflect whether these methodologies could be effective for overrun charging. Welsh Power welcomes the suggested approach of all methodologies being an ancillary document to the CUSC and therefore permitting changes to the methodology being raised by CUSC signatories.

One of the principles of overrun charging under the cost recovery methodology is "overrun charges would include all costs incurred, by National Grid as the GBSO,…… whether taken in the BM or outside of the BM (i.e. intertrip costs or warming contracts etc…)". The rationale behind why actions such as intertrips and warming contracts are being included with the overrun calculation would be appreciated. It is difficult to understand why the costs of warming contracts are included when no physical delivery may occur, whilst the intertrip involves locational specific plant which may not be associated with the location of where the overrun has arisen due to no physical interaction being possible. Will the following actions also be included Schedule 7 and PGBT's? If all these actions outside of the BM are incorporated within the overrun charge, what is the magnitude of change upon cash-out prices?

Please do not hesitate to get in touch if you wish to discuss any of the points raised.

Yours sincerely

R Williams

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British Energy

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21 November 2008

Dear Patrick,

British Energy response to the pre-consultation document GB-ECM 14 Consequential impact of CUSC Amendment Proposals 161 – 164.

The British Energy group of companies welcomes the opportunity to respond to the above consultation. British Energy own and operate eight nuclear power stations as well as Eggborough Power Station (a large coal plant with two units fitted with FGD) and four small embedded gas generator sites. Two of our nuclear stations are located in Scotland accounting for approximately 2300MW of capacity. We also have interests through a joint venture in developing an island windfarm in Scotland.

Our response will comment on each CUSC amendment in turn however our key points are summarised below:

- Whilst we recognise the possible impact on those parties making BSUoS payments that could be introduced by CAP161 we believe that appropriate incentives can be developed to ensure that these risks are minimised.

- We support the implementation of the Simple methodology for the pricing of CAP162 Entry Overrun and believe that its effectiveness should be kept under review. We do not support the Marginal Methodology.

- Under CAP163, assuming that the wider locational TNUoS tariff is appropriately recovered from the donor party (and that mechanisms are put in place for the recovery of revenue from local and residual TNUoS tariffs prior to implementation) we agree that no additional use of system charge need be levied under this amendment.

- We are aware that the working groups have continued to discuss alternatives for a more cost reflective alternative to CAP164 and would support such a proposal. We do not support a TNUoS based charge being passed through BSUoS.

CAP161
British Energy supports a pay as bid mechanism for CAP161 under the assumption that access is assessed against the binding constraint and that the bidder is in competition with other users behind the same constraint. Furthermore we believe that pay as bid in an auction for the release of scarce access in the short-term is appropriate. However we are a concerned about the lack of visibility to the user in initial stages following any implementation of this amendment and therefore support full publication of data following each bidding round.

We also note that the report has yet to publish a methodology for assessment of applications and believe that industry should be given appropriate opportunity to comment further on this.

We note that all of the options for SO release of access introduce a risk that BSUoS may increase or decrease and that for CLDTEC the SO is potentially required to assess the system over a 42 week period. However we believe protection to third parties should be addressed via appropriate incentives on the SO.

We believe that the running of the auction process should be subject to an ongoing review and we would support an initial five day a week auction (which would cater for all seven days of each week).

We feel that industry parties will make use of CAP161 where they do not hold sufficient long term entry capacity and we believe that a party would bid for access in line with what they can achieve in the energy market.

British Energy supports an implementation date of April 2010 and believes that recovery of the residual and local elements of TNUoS tariffs can be addressed in these timescales. We do not believe that the outcome of GB ECM 13 should be pre-judged and the existing mechanism for the recovery of the residual revenue (i.e. capacity based charges) should be maintained.

CAP162
British Energy considers Entry Overrun as the bedrock of the short term measures for access and believes that this amendment clarifies an uncertain area of the CUSC where consequences of breaches are not robustly defined.

British Energy supports the implementation of the Simple overrun pricing methodology as we believe it represents an appropriate balance between cost reflectivity and transparency. We favour the transparency of this option due to the ex-ante publication of scalars.

We believe that following implementation of the Simple Methodology that its effectiveness should be subject to a thorough review to consider if it is providing appropriate signals to industry parties and appropriate protection to those not making use of Entry Overrun. For example the correlation of (BSUoS – RCRC) with constraint costs may become more pronounced and following a review there may be opportunity to further simplify this methodology with greater ex ante publication of tariffs. However if this option proves to be insufficient protection to third parties the Cost Recovery methodology should be considered for further development. We do not support the Marginal overrun pricing methodology and will comment on this separately.

Our specific comments on the Simple Methodology are that:
- We support the National Grid view of using a volume weighted Scalar.
- We believe that the charge for overrun should be cost reflective of short term cost of access and not based on locational TNUoS which considers the Long Run Marginal Cost of access
- We support differential scalars for Import and Export as these should be more cost reflective, however this is a consideration for a review of the methodology following implementation.

Regarding the use of negative prices within the three methodologies, we believe that whether parties receive payment for overrun should be determined on a principles basis and therefore should be incorporated in all three options (Simple, Cost Recovery and Marginal) or not at all.

As we support the implementation of the Simple Methodology we do not consider that it is a temporary mechanism but should be reviewed once experience has been gained. Were it to become apparent that the Cost Recovery methodology should be pursued we could lend some support to the suggestion that the Simple methodology is used when in a default period.

Under the Simple Methodology the zones should be fixed on a forecast view of appropriate Operational zones. However the improved cost reflectivity which the Cost Recovery methodology provides would suggest that (if this methodology was chosen) a more accurate real-time view of Operational zones would be appropriate. The production of nodal or zonal tariffs from the Marginal Methodology can be considered a secondary concern until this option is better understood and is subject to further analysis and testing.

Option 3: Marginal Methodology

The proposed load flow model builds on the methodology of the TNUoS calculations to distinguish between the short-run and long-run marginal cost of access at each node. The LRMC is the cost of assets used to support transmission of an extra megawatt from a node; this is measured by the change in total MWkm in the load flow solution and used to set the wider locational element of TNUoS.

Starting from these calculated load flows - the unconstrained solution - the locational marginal price of power at a node is the sensitivity to an extra megawatt injection at the node of the total cost of taking bids and offers to constrain the load flow on each line to within operational limits. The SRMC of access at a node is the difference between the Locational Marginal Price (LMP) at the node and the LMP at a reference node.

Whilst this model has an abstract theoretical appeal, it is clear that there are substantial practical difficulties to its implementation. For example, the operational constraints encountered do not relate only to load flow on lines, but also to headroom / reserve requirements; similarly, the bid and offer prices are only a part of the cost of constraints, as there are also intertrip costs, contracted STOR provision and so forth. These costs are explicitly considered in the "degut" (Cost Recovery) methodology, but it is unclear how the Marginal model could be adapted to include them. If this is done, the methodology is no more automated or objective than the "degut" methodology.

Furthermore, we do not believe that the Marginal methodology is properly understood by industry and therefore should not be implemented without further analysis, testing and detailed consultation. The Excel prototype model is insufficient on which to base a decision for implementation of a pricing methodology. We are concerned that this methodology does not fulfil the principles of Locational Marginal Pricing as it does not, for instance, incorporate any dynamic demand side participation.

The likely costs for the development and implementation of the model are daunting, and potentially disproportionate to the benefit (if any) over the Cost Recovery and Simple methodologies, and should be subject to a thorough cost benefit analysis. Finally it is far from apparent that the Marginal methodology will not lead to significant over-recovery, given the expected concentration of use of the over-run product in (exporting) positive TNUoS zones.

CAP163

British Energy support the implementation of access sharing on a nodal basis and believe that it will be most effective if the arrangements are clear and simple to allow generators to make advance decisions about their access.

Assuming that the wider locational TNUoS tariff is appropriately recovered from the donor party (and that mechanisms are put in place for the recovery of revenue from local and residual TNUoS tariffs prior to implementation) we agree that no additional use of system charge need be levied under this amendment.

British Energy has previously been involved in the temporary exchange of entry capacity and believes that this amendment enhances those arrangements. This proposal has the potential to be very effective in making efficient use of the transmission system. We note however that entry capacity sharing will be greatly more beneficial if CAP162 is also implemented.

CAP164

The socialised cost of constraints under CAP164 original is too significant a cross-subsidy for British Energy to believe that the amendment is cost reflective or better than the baseline. However we are aware that the CUSC working group have been considering an alternative to CAP164 which will address this cross-subsidy whilst still providing new projects with the connection and charging certainty they need for funding.

Whilst we recognise the likely impact on TNUoS tariffs should the CAP 164 Original be implemented we believe that TNUoS charges should continue to be asset based. Furthermore the alternative being discussed by the working group should minimise this effect (this assumes that mechanisms are put in place for the recovery of revenue from local and residual TNUoS tariffs prior to implementation).

We do not think that the TNUoS calculation should be amended to over recover and then the revenue channelled to BSUoS. This would suggest that the LRMC signals are being used to address a SRMC. Furthermore the TNUoS tariffs are calculated on the basis of a 27:73 split between demand and generation and the BSUoS charges are split 50:50 which will introduce further cross-subsidy across industry parties.

Please contact me directly should you need clarification on any of our comments.

Yours sincerely

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14th November 2008

Dear Patrick,

EDF Energy response to CAP 161, 162, 163 & 164 charging pre-consultation

We are pleased to have the opportunity to comment on the pre-consultation and thank National Grid for its efforts in administering it.
EDF Energy did not support the implementation of the CAPs 161,162.163, 164 as we do not believe it will provide 'bankable' capacity for investors aiming to connect new generators.
However we have some opinions on the charging for these amendments, should they be implemented. Please be aware that our opinion on the most appropriate charging option for Overrun (162) depends on the availability of firm transmission capacity.

Our view on charging can be summarised by the following:
- We expect the planning and operational standards to ensure that the overall costs incurred both in the long and short run are acceptable;
- The structure of charges should reflect how costs are incurred, so fixed investment costs and marginal operating costs should be charged as fixed and variable costs;
- Cost-reflective charges should relate to either the long-run investment costs of the system or the short-run operational costs of the system;
- We rely on NGET's charging in order to ensure charges are cost reflective, fair and provide no significant perverse incentives;
- We allow for reasonable approximations in order for simplification and believe current TNUoS charging strikes the right balance between cost reflectivity and simplicity.

We accept that there is an asymmetry between shorter-run constraint costs and the cost of investing in transmission and are fearful of massive increases in cost that can be incurred when operating a constrained system.

These shorter run costs are so significant that it is essential charging arrangements ensure that short-run over allocation of transmission rights are not excessive or can be abused. Therefore the "polluter pays" principle should apply.

We therefore believe the following charging arrangements meet EDF Energy's requirements:
- CAP161 – the ability for NGET to reject bids if receipts would not be higher than costs;
- CAP162 – the simple X * [BSUoS] charge[1];
- CAP163 – the exchange rates based on nodal ex-post overrun charges;

[1] Should all firm rights be withdrawn and only CAP162 implemented the Marginal methodology would be more suitable as the Simple approach would not be fit for purpose

However the <u>BSUoS charging for CAP164 clearly does not</u> meet EDF Energy's requirements.

Yours sincerely,

David Scott
Electricity Regulation

Cap 161 SO Release of Short-term access

Q1 Should the process for So Release auctions afford more protection to third parties (general BSUoS payers)?

- The intention of the original amendment in protecting BSUoS payers is reasonable – the ability for NGET to refuse to accept bids if they are less than the forecast constraint costs is adequate protection.

Q2 Should the process for calculating CLDTEC afford more protection to third parties (general BSUoS payers)?

- We do not support CLDTEC.

Q3 Do you think the auction process should run overnight and / or weekends?

- The auction process should be as close to real time as possible including weekends. Over time we would expect the auction to come closer to real time as per the development of gate closure in the forward markets.

Q4 Would you use an SO release product, and if so which aspects are appealing and which are concerning?

- As an investor in new generation the SO release product would not be useful as EDF Energy would not be able to raise finance against it. It is also unlikely that EDF Energy's stations at Cottam, West Burton and Sutton bridge would require the product because TNUoS charges these stations face are probably not high enough for EDF Energy to risk using the SO release product.

Q5 National Grid welcomes views on the approach (commoditisation based on MWh usage) to revenue recovery if a form of SO Release is implemented prior to revised residual changing arrangements being implemented, and welcomes other alternative options.

- The local capacity nomination proposal outlined in the Residual charging consultation is EDF Energy's favoured approach.

Cap162 Entry Overrun

Q6 Which is you preferred charging model and why?

- If overrun is implemented alongside a package of other access options, including "firm" access rights we consider the "Simple" proposal as being fit for purpose.
- EDF prefers Option 3 simple charge [X*(BSUoS –RCRC)] with as few zones as possible (maybe the 17 SYS boundaries or the 24 in the consultation); although we'd wish this to be refined to simply [X*BSUoS] as the energy imbalance charge and resultant RCRC charge are not the actual costs the overrunning generator places on the system.
- BSC parties are exposed to imbalance through the Energy Imbalance Charge (EIC) which is a payment associated with either short or long volumes

multiplied by SBP or SSP respectively. Energy imbalance cash-out prices (SBP/SSP) aim to represent the marginal cost of replacement energy, not system actions, such as constraints[2]. The aim of the EIC is not to recover the cost of the GBSO resolving the net imbalance of contract notifications against demand; rather it is an incentive for parties to self-balance and settles the gross imbalance of all parties. The net value of these cash-flows between parties and the GBSO is redistributed through the Residual Cashflow Reallocation Charge (RCRC) charge. This is the difference between the SSP & SBP prices and the respective party imbalance volumes to which they are multiplied. RCRC therefore does not equate to the cost of resolving the net imbalance. The actual cost of net imbalance is the bid or offer cashflows between the generator and the GBSO, which is included in BSUoS either as bid or offer revenues. This means that when the system is long, bid receipts may depress the overrun charge somewhat (if there is no offer side action accompanying it), however the actual cost of overrunning, which is constraints, will still be reflected by the bid-offer spread of bids with corresponding offer side actions.

Q7 Under the simple methodology do you think the Scalar should be calculated by Volume or Settlement Period weighting and why?

- No comment

Q8 Do you think the charge for overrun should be set at an asset based charge derived from TNUoS?

- No. The costs created are not asset based, but operational based; it would be incorrect to charge an operational cost on an investment cost: this is the very flaw of Connect & Manage.

Q9 Would you consider using Overrun, and if so which aspects are appealing and which are concerning?

- EDF Energy would consider using Overrun, especially if it had the [-RCRC] element removed as in the majority of occasions the cost of overrunning should not be significant. Usage would depend on the other reform options, CAP161 (SO release of Short Term rights) and CAP163 (Entry Capacity Sharing); as the amount of capacity released under CAP161 would affect the price of Overrun. If solely CAP166 (Long Term Auctions) is implemented alongside CAP162, the use of Overrun may be significant for older plant unable to fund incremental capacity in the LT auction.
- It is feasible that overrun be implemented in isolation, after the withdrawal of firm rights.

Q10 Do you think the Simple Methodology (Option 1) should differentiate import and export?

- Yes.

Q11 Do you think that the Cost Recovery Methodology (Option 2) should be developed to include negative charges, if so which variant?

- No, the cost recovery concept should not be developed.

[2] P217, recently approved by ofgem aims to eradicate the pollution of cash-out prices by constraint actions. P217 will remove most "pollution" of cashout prices and hence of RCRC by constraint-related effects rendering any past correlations between RCRC and BSUoS, weaker

Q12 Do you consider the simple methodology would be a reasonable default mechanism?

- Yes.

Q13 Should the Simple Methodology include negative prices?

- Yes.

Q14 Under a nodal model, how should the zones for simple and Cost Recovery tariffs be constructed: Operational Zones, daily (not for simple) or TNUoS based?

- Confused by this question…nodal and zonal…however:
- EDF Energy has consistently regarded the development of zones as a reasonable sacrifice in cost reflectivity for the benefit of simplicity. We note the WGs' progress towards a more nodal philosophy in both Overrun (162) and Sharing (163) and realise that if nodal sharing exchange rates are to be based on ex-post Overrun charges then nodal tariffs would be required. At present the modifications are not defined such that it is simple to see the benefits between zonal and nodal charges.

Q15 National Grid is interested in respondents views on whether the Marginal Methodology should produce zonal or a nodal Overrun tariffs?

- Locational marginal Pricing is a very interesting concept that would require significant investment in systems and processes both for the GBSO and EDF Energy. Should CAP162 (Overrun) be the only access modification to be implemented it is clearly the most suitable charging option as the simple BSUoS charge would not be fit for purpose). For instance if no generators have "firm" capacity rights then it would be worth investing in it, yet, should firm access rights remain, the corollary is true.
- Should the LMP model be developed it would be advisable to use a nodal approach.

CAP163 Entry Capacity sharing

Q17 Would you consider sharing access, and if so which aspects are appealing and which are concerning?

- The concept of sharing is favourable to EDF Energy, as it is possible that larger generators (in expensive TNUoS zones) may reduce the TEC they require, thus allowing new generators onto the system with firm, bankable capacity.

Cap164 Connect and manage

Q18 Do you think an asset based charge is appropriate and what is your rationale?

- No an investment based charge should not be levied when the cost is operational.

Q19 Do you think the TNUoS calculation should be amended to over recover and then channel this revenue in to BSUoS to partially offset the increase in BSUoS?

- Connect & Manage should not become a contagion that sacrifices all cost reflective principles applied by the GBSO. Unjust cross subsides are not resolved by introducing another.

Q20 Would you apply for early connection, and if so for what volume, number of years advancement of your project this represents and what SYS zone is the project in?

- Not known.

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21 November 2008

Dear Pat

Pre-consultation document GB ECM-14
Consequential impact of CUSC amendment proposals 161, 162, 163 and 164

As you know, Scottish and Southern Energy (SSE) has long had strong concerns regarding the piecemeal approach adopted by National Grid to modifications to the Transmission Network Use of System (TNUoS) charging methodology. Consequently, we welcomed the joined-up approach to assessing the CUSC amendment proposals arising from the Transmission Access Review that sought to consider charging modifications in parallel with changes to the commercial access regime.

Consistent with this spirit of joined-up thinking, we are assessing the implications of this pre-consultation, further consultation GB ECM-08, pre-consultation GB ECM-13, pre-consultation GB ECM-15, pre-consultation GB ECM-17 and Ofgem's impact assessment of GB ECM-11 together. It is our intention to submit a combined response to all six documents on 4 December 2008. If pre-consultation GB ECM-16 is published before that date we would hope to also be able to include our initial thoughts on that document.

We hope that by providing a full response that considers all of the 'live' modification proposals, our response will be of greater value to National Grid in further developing this work than a number of individual responses. However, if you would like to discuss this further then please do not hesitate to give me a call.

Yours sincerely,

Aileen McLeod
Regulation Analyst

4 December 2008

Transmission Charging

This paper addresses those issues under consultation in GB ECM-11 For the charging arrangements for generator local assets; GB ECM-13 For the treatment of the residual generation tariff in the calculation of TNUoS tariffs; GB ECM-14 Consequential impact of CUSC Amendment Proposals 161, 162, 163 and 164; GB ECM-15 Long term fixed TNUoS tariffs; and GB ECM-17 Transmission charging – a new approach. It is also mindful of the recent further consultation GB ECM-08 Modification proposal to the TNUoS charging methodology to introduce charging arrangements associated with offshore transmission networks; and the proposed future consultation GB ECM-16 Long term entry capacity auctions.

Summary

Following publication of the Energy White Paper 2007 and the Transmission Access Review, the GB electricity industry has committed to reassess the commercial arrangements governing generation users' access to and use of the GB transmission system.

Underpinning this work are the substantial security of supply challenges resulting from the scheduled closure by 2020 of up to one third of the existing UK generating capacity, and the legally binding targets to reduce greenhouse gas emissions set out in the Climate Change Act 2008. To meet this future energy challenge, significant investment in new generation capacity (both renewable and low carbon conventional technologies) is required. It is widely accepted that stability and certainty in the regulatory and policy frameworks are essential to achieving sufficient, timely investment.

Scottish and Southern Energy (SSE) strongly believes that the current arrangements for charging for access to the GB transmission network do not encourage investment in new generating capacity. We have argued for a number of years, and presented detailed evidence to support our arguments, that the incremental cost related pricing model used by National Grid in setting Transmission Network Use of System (TNUoS) tariffs is not cost-reflective. Further, the resultant TNUoS tariffs are extreme, volatile and unpredictable. In this charging environment, it is nearly impossible for a potential investor to gain the medium to longer term confidence over charges that is necessary for it to commit to the substantial investments required to achieve new GB generation capacity.

In our view, there are three sets of interlinked issues that need to be solved if the charging arrangements for generation users' access to and use of the GB transmission system are going to be fit for purpose. These are to put in place:

- An approach to charging for connection to the network that enables informed network investment decisions and, hence, minimises the exposure of other users to inefficient or stranded assets;
- A regime for charging for use of system that supports ongoing investment and operational decisions through the right balance between cost reflectivity, stability and predictability; and
- Charges for use of system that are consistent with the objective of maximising utilisation of the existing (and future) transmission network.

In summary, this means clear, cost-reflective charges for new connections to the network; stable, non-discriminatory charges for ongoing use of the network; and charging for usage rather than to reserve capacity.

To achieve this, we support a charging regime with a framework as follows:

- **Generator only local assets** For those transmission assets used solely by generation user(s), a user-specific charge that reflects the upfront capital cost and ongoing maintenance cost of those local assets.
- **Wider shared transmission assets** For the parts of the transmission system used by both generation and demand users, a uniform commodity charge that is levied on generation users based on their measured export onto the transmission system.

All generation users connected to the GB transmission system would be liable for both the local and wider charges. Embedded generation users with a Bilateral Embedded Generation Agreement (BEGA) would be liable for the wider charge only.

Implementing this regime would result in a change in generation users' charges. All generation users would be affected; in general, two main factors would determine the scale of the change experienced by individual users. Firstly, the combination of a user-specific local asset charge and a uniform commodity charge would result in a change to the locational signal to reflect the distance from the existing network rather than the distance from demand. In addition, negative charges would be removed. Secondly, replacing the capacity reservation charge with a commodity charge would result in a reduction of charges for low load factor generators and an increase in charges for high load factor users.

Based on information in the public domain, we estimate that around 60% of generation users would experience a reduction in charges, including all renewable generators. Of those generation users that would experience an increase, we estimate that less than 10 users would experience an increase of more than £5 million per annum (of which, the majority are currently liable for negative charges).

Going forward, we are mindful of the transmission tarification guidelines published by the European Regulators Group for Electricity and Gas (ERGEG). These guidelines advocate harmonisation of use of system charges for generator across Europe and, to achieve this, we would support a gradual reduction in the wider shared asset charge in GB towards zero.

The definition of 'local' and 'wider' transmission assets

SSE supports a framework for charging generation users that has separate elements for local and wider transmission assets.

The rationale for this is simple. Local, generator only, transmission assets provide the physical link between the generator and the transmission system; without the generator these assets would be redundant. Given that no other user benefits from the provision of local generator assets there is a strong case that the connected user should be liable for the absolute cost of those assets. In contrast, the wider transmission system has multiple users (both generation and demand users) resulting in power flows variable in both time and magnitude that are difficult to 'tag' to any individual user. The security and quality of supply standard for the wider shared transmission system is significantly more onerous than for local generator assets and, hence, in most instances the dependency of individual users on individual assets is tenuous. Given this, there is a strong case for charging users for actual use of the wider network.

It is important, for charging purposes, to have a clear, simple, unambiguous distinction between local and wider transmission assets, as follows:

> **Generator only local assets** comprise the electrical connection between one or more generating units and the wider transmission system.
>
> The **wider shared transmission system** comprises the Main Interconnected Transmission System (MITS) (as defined in the GB Security and Quality of Supply Standard) and those parts of the GB transmission system that are required for the supply of power at Grid Supply Points (GSPs), i.e. any apparatus which if removed would reduce the supply capacity a GSP.

Consistent with the rationale for local and wider charging set out above, this definition clearly distinguishes between those local assets used only by generation user(s) and those wider shared assets which are used by both generation and demand users.

This approach is different from that proposed by National Grid in GB ECM-11 (and subsequent modification proposals) which seeks to distinguish local and wider transmission assets through the definition of a MITS node as follows:

> **Main Interconnected Transmission System (MITS) nodes** are defined as:
>
> - A GSP connection with 2 or more transmission circuits connecting at the site or;
> - More than 4 transmission circuits connecting at the site.
>
> Where a GSP is defined as a point of supply from the GB transmission system to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its local charge. A transmission circuit is part of the GB transmission system between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

Under GB ECM-11, generators directly connected to a MITS node would not be liable for a circuit based local charge. Generators not connected to a MITS node would be liable for a circuit based local charge.

National Grid explains that the definition of a MITS node "was aimed at identifying local assets that exist to connect generation only". The definition proposed achieves this for the 275kV and 400kV supergrid and those 132kV elements of the system operated in parallel with the supergrid. However, the definition takes no account of the radial parts of the GB transmission system that are shared by both generators and demand; hence, overall the definition fails to achieve National Grid's stated aim.

This means that, if National Grid's proposed definition of a MITS node was implemented, generator users would be liable for a local charge, ostensibly for generator only local assets, that includes for assets necessary for demand security. An example of this would be Farr windfarm which, as proposed, would be charged a local charge for circuits that also secure demand at Boat of Garten GSP. Hence, while we support the intention behind National Grid's proposal, we do not agree that the proposed definition of a MITS node is consistent with this intention.

Charges for generator only local assets

As described above, we believe that there is a strong case that generation users should be liable for the cost of their generator only local assets. National Grid has proposed such change to the charging methodology in modification GB ECM-11, and we support the principle of a cost-reflective local charge with respect to both facilitating economic and efficient connection designs (as set out in GB ECM-11) and wider reform of the charging framework (discussed here). Importantly, this approach would ensure that the wider customer base is not exposed to inefficient or stranded generator only transmission assets.

That said, and in common with the majority of respondents to the August 2008 consultation, we have real concerns with the modification to the TNUoS charging methodology that National Grid has proposed to introduce a local asset charge (as set out in GB ECM-11 Conclusions Report). It is clear from the worked example presented in the August 2008 consultation that the local asset charge proposed under GB ECM-11 is demonstrably not cost-reflective and, as a consequence, we do not support the modification proposal.

Over the past two and a half years, the industry has examined the issue of charges for generator only local assets in significant detail. It is widely agreed that such a charging approach is necessary, and that the charge should be cost-reflective without reintroducing the perceived disadvantages of a deep connection charge (for example, other users' actions, disaggregation of shared assets and the allocation of 'strategic' investment). The modification proposal GB ECM-11 goes some way to achieving this goal, but the real and important outstanding industry concerns need to be met. In this regard, it is disappointing that National Grid has opted not to make any changes to its proposals in light of responses to the August 2008 consultation.

We believe that there is scope to amend National Grid's GB ECM-11 proposal to address industry concerns, and we would support the following changes:

- Use of 132kV and 275kV overhead line and cable expansion factors that are specific to the affected Transmission Owner. In addition, given the potential range of circuit costs and the small database, application of a 'sense check' where if the actual expansion factor varies from the generic expansion factor by more than, say, 20% a circuit specific expansion factor is used.
- Circuit specific local security factors that accommodate partial redundancy in the connection design.
- As described above, a change to the definition of a MITS node that takes account of the radial parts of the GB transmission system that are shared by both generation and demand users.
- A review of the connection-infrastructure boundary, which currently states "Where customer choice influences the application of standard rules to the connection boundary, affected assets will be classed as connection assets", to ensure that this is not resulting in the same assets being categorised as connection for one user and infrastructure for another.

The changes proposed above would improve this modification proposal with respect to National Grid's relevant objectives of facilitating competition, cost-reflectivity and taking account of business developments. It would also remove the potential for discrimination between onshore and offshore generation users. Circuit specific local expansion factors and local security factors (as we suggest above) have been proposed by National Grid in the October 2008 further consultation GB ECM-08 Modification proposal to the TNUoS charging methodology to introduce charging arrangements associated with offshore transmission networks; hence, the changes proposed above would align onshore and offshore charging arrangements.

Charges for wider shared transmission assets

Capacity or commodity?

Historically, it has been argued that investment in the transmission system has been incurred on a capacity basis in order to meet winter peak demand. Taking into account the predominance of high load factor, reliable generation, this has resulted in charges for use of the transmission system being levied on a capacity basis, i.e. a £/kW capacity reservation tariff.

It is fair to say that, having been through a long period of relative stability in generating conditions, the GB electricity generation market is now going through a period of unprecedented change. This change is manifest regardless of plant age and condition, technology, fuel or location. Carbon-based generators are now subject to stringent environmental and emissions controls. Renewable technologies are encouraged and incentivised as a result of national and European policies and, increasingly, legislation. The future for nuclear generation in GB remains uncertain given, in particular, likely obstacles in the planning process. More generally, commodity and fuel prices are volatile, and supply businesses are seeking change in response to the demands of their customers.

These, and other, factors have contributed (and continue to contribute) to significant changes in the operation of generation users and, hence, their use of the GB transmission system. While we agree that investment in generator only local assets is scaled to meet peak export capability (and, through a local asset tariff, should be charged for on this basis), we believe that it is becoming increasingly untrue that investment in the wider shared transmission system is – or, indeed, should be – on the basis of meeting generators' peak export capabilities. This has been recognised by the transmission businesses and is being progressed through a fundamental review of the system planning standard.

Investment in the GB transmission system is increasingly being driven by the changing requirements of generation users. Overall, generation capacity is forecast to increase by around 40% by 2015. The volume of intermittent and low load factor generation has increased, and this rise is expected to continue. Against this background, demand forecasts are also changing in response to slowing consumer demand and increasing distributed generation; overall growth of less than 5% is expected by 2015.

Given, in particular, the changing operation of generation users and necessity to grow the plant margin (as the volume of intermittent generation increases), we believe that it is no longer appropriate or relevant to charge generation users for use of the wider shared transmission network on the basis of capacity reservation. Generation users will not all be able to respond to conditions of peak demand, and investment in the transmission system will no longer expect this. Hence, we believe that the prevailing (and future) conditions are more suited to a charge for generators which is based on utilisation.

Uniform or locational?

For the reasons described below, we believe that the utilisation charge should be levied as a uniform charge across GB determined from the total annual revenue requirement (£) divided by the total annual generation export (MWh). Each generator user would be liable for the utilisation charge (£/MWh) multiplied by its total metered export over the year (MWh).

Such a charge would be transparent, predictable and stable; hence, facilitating effective competition in generation, in particular through the promotion of a stable climate for investment. It would recognise the developments in the GB electricity generation market and the use of the transmission system, and the consequential changes to the way the transmission licensees plan and run their businesses (as discussed above).

We recognise that the key concern around implementing a GB wide utilisation tariff will be cost reflectivity and, in particular, the impact on cost reflectivity of removing the locationally varying element of the tariff. It is true that a uniform tariff would represent an average charge and, hence, would not exactly reflect an individual user's impact on the costs of the transmission network. However, there is strong evidence that the current locationally varying element of the tariff is no more cost-reflective than a uniform tariff approach. Consequently, we believe that replacing a charge that is not cost-reflective with an average charge is a relative improvement, and the case is compelling when the many other benefits of a uniform tariff, such as year-on-year stability, are also taken into account.

Considering the specific issue of the cost-reflectivity of the current TNUoS tariff, the correlation between TNUoS (specifically, the locational element) and transmission investment has been examined in detail as part of the Transmission Access Review. The conclusion reached was that TNUoS is not a good proxy for network investment. To illustrate this, National Grid presented the example of reinforcements to the shared transmission system necessary to connect new generation near London. The prevailing TNUoS tariff is negative, meaning once connected the new user would receive an annual payment, yet to provide the connection requires investment of £70/kW.

In response to this, it is argued that, although investment is required to connect the near London generator, the overall cost of connecting this generator is negative because an equivalent sized generator further from London is no longer required, i.e. demand requirements can be satisfied by the new near demand generator, removing the need for the costly remote transmission system. As recognised within the charging statement, this argument is somewhat narrow in scope, particularly as it takes no account of the long life of existing generation and transmission assets – which don't just disappear on the connection of a new, substitute, generator.

While this argument might be credible in times of low plant margin, the validity of the argument is stretched as the volume of intermittent and low load factor generation users grows. We do not believe it is cost-reflective to attribute a negative charge to, for example, an offshore windfarm located near London that requires many millions of pounds of transmission investment to connect and yet makes a negligible contribution to security of supply.

A charge that accurately reflects the costs of an individual generator's connection can be easily put in place through a local asset charge. A cost-reflective allocation of the costs of the wider shared transmission network is best achieved, in our opinion, through a uniform commodity charge. Alternative approaches to allocating the costs will not be cost-reflective when considered over the lifetime of generation and transmission assets, not least as power flows become more variable in response to the changing generation mix and a growing plant margin. An allocation of costs that is right on average is preferable to an allocation that is demonstrably wrong for everyone.

<u>Impact of a uniform commodity charge</u>

The total revenue recovered from generation users in 2008-09 is around £365 million. If a generator only local asset charge was introduced, this would recover around £35 million. We propose that the remaining £330 million would be recovered through a uniform commodity charge for use of the wider shared transmission assets.

Based on information in the public domain, we estimate that the combined impact of the local asset and wider commodity charges would be a reduction in charges for around 60% of generation users, including all renewable generators. Of those generation users that would experience an increase, we estimate that less than 10 users would experience an increase of more than £5 million per annum (of which, the majority are currently liable for negative charges).

The main impact of the combined local asset and wider commodity charges would be the introduction of stability and predictability in transmission charging. This, we believe, would be welcomed by an industry that is required to make significant investment and operational decisions in coming years.

Consider the impact on, for example, operational decisions at an aging thermal plant that has opted-out of the Large Combustion Plant Directive. This user has to decide how to profile the use of its remaining operational hours between now and 2015. The current charging regime encourages early use of the hours as the charge is based on capacity not use, and there is uncertainty about future charges. Local asset and wider commodity charges would provide certainty over costs and not penalise the generation user for its low load factor.

Liability for the local and wider charge

All generation users connected to the GB transmission system would be liable for the local and wider charges. Embedded generators with a BEGA would be liable for the wider charge only.

The generator only local asset charge would be determined for each generation user and comprise a circuit and substation element. The wider shared asset charge would be determined annually from the known revenue requirement and a forecast total generation export. Generation users would be charged monthly for the previous month's metered export.

Conclusions

In conclusion, SSE strongly believes that the current arrangements for charging for access to the GB transmission system do not encourage investment in new generating capacity. Furthermore, the GB electricity market is going through a period of unprecedented change and this is, in turn, driving unprecedented change in the way that the GB transmission system is planned and operated. We believe that the charging arrangements need to be reformed to reflect both the necessity for new investment and the evolution in the way the system is used.

We support a charging regime that comprises clear, cost-reflective charges for new connections to the network; stable, non-discriminatory charges for ongoing use of the network; and charging for usage rather than to reserve capacity.

Our views on the charging modification proposals currently under consultation are summarised below. While we comment on each proposal in isolation, we note that the impact of these proposals is cumulative and interactive. Hence, we support a wider 'joined-up' reform of the charging methodology (as described above) rather than a series of 'piecemeal' modifications.

GB ECM-11

For the charging arrangements for generator local assets

We support the principle of a cost-reflective local charge for generation users with respect to both facilitating economic and efficient connection designs (as set out in GB ECM-11) and wider reform of the charging framework.

However, we have real concerns with the modification to the TNUoS charging methodology set out in GB ECM-11 Conclusions Report and, as a consequence, do not support this amendment. Our key concern, as we demonstrated in our response to the August 2008 consultation, is that the local asset charge proposed under GB ECM-11 would not be cost-reflective.

To improve the cost-reflectivity of National Grid's GB ECM-11 proposal, we believe the following changes are required:

- Use of 132kV and 275kV overhead line and cable expansion factors that are specific to the affected Transmission Owner. In addition, given the potential range of circuit costs and the small database, application of a 'sense check' where if the actual expansion factor varies from the generic expansion factor by more than, say, 20% a circuit specific expansion factor is used.
- Circuit specific local security factors that accommodate partial redundancy in the connection design.
- As described above, a change to the definition of a MITS node that takes account of the radial parts of the GB transmission system that are shared by both generation and demand users.
- A review of the connection-infrastructure boundary which currently states "Where customer choice influences the application of standard rules to the connection boundary, affected assets will be classed as connection assets", and results in the same assets being categorised as connection for one user and infrastructure for another.

The changes proposed above would improve this modification proposal with respect to National Grid's relevant objectives of facilitating competition, cost-reflectivity and taking account of business developments.

GB ECM-13

For the treatment of the residual generation tariff in the calculation of TNUoS tariffs

We support the principle of charging generation users for use of the GB transmission system on the basis of utilisation rather than capacity. We believe that an utilisation charge would most appropriately reflect the use of the system by an increasingly diverse mix of generators, and the consequential impact on the way the transmission system is being planned and operated.

We note the proposals to modify the way in which the residual element of the TNUoS generation tariff is calculated and levied, which includes options to commoditise the residual charge based on total annual metered generation or annual metered generation during the daily peak. While we support the principle of a commodity charge, and hence believe that the options proposed under GB ECM-13 are worthy of further consideration, we believe that commoditising only a part of the charge (the residual) would be insufficient.

It is not proposed under GB ECM-13 to revise the methodology for determining the locational element of the TNUoS tariff. The transport model used to calculate the locational element is intended to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system that provides bulk transport of power. It is, crudely, based on calculating the investment cost associated with adding a megawatt of generation at a specific location. This approach was adopted as a response to the view that investment in the transmission system was incurred on a capacity basis in order to meet winter peak demand; hence, it was appropriate to determine the charge on a capacity basis.

There is growing evidence, with which we concur, that a key factor in decisions about investment in the transmission system is to provide capacity that meets the expected utilisation. This evolution in the system planning process is in response to the changes in the generation mix and how those generation users operate their power stations. It is certainly not the case that a megawatt of wider shared transmission capacity is built for each megawatt of generation that connects.

The modifications proposed to the way in which the residual element of the TNUoS generation tariff is calculated recognise this evolution in the system planning process. If these modifications were implemented it would result in different underlying assumptions to the locational and residual element of the TNUoS tariff. This position is, in our view, not credible and, hence, we cannot support a change to the residual tariff without an equal and corresponding change to the locational tariff. Specifically, we believe that there should be wider shared transmission charge (recovering the sum of the current locational and residual elements) that is levied as a uniform charge across GB.

GB ECM-14

Consequential impact of CUSC Amendment Proposals 161, 162, 163 and 164

SSE supports the high level principles for charging set out by Ofgem: cost-reflectivity, simplicity, transparency, predictability and the facilitation of competition. Hence, we support a charging methodology that charges generation users the cost of providing access to the network (through a generator only local asset charge) and a charge based on their utilisation of the network (through a wider shared asset charge). This charging framework would apply to all generation users connected to the transmission network and licensable users embedded within the distribution network, regardless of the access product used.

We note the proposals under GB ECM-14 to levy only a local asset charge and a residual charge on generation users with a short term access product (SO release, overrun or sharing). These users would not be liable for the current locational element of the TNUoS charge. Notwithstanding our view that fundamental reform of the charging methodology is required, we have serious concerns with the proposed modifications set out in GB ECM-14 and believe that, if implemented, these modifications could result in an internally contradictory charging arrangements that might have perverse consequences.

Our main concern relates to the allocation of costs. We agree that all generation users should be liable for a charge that reflects the costs of providing the local assets necessary for their connection to the GB transmission system. We also agree that all generation users should be liable for a charge for the wider shared transmission system on the basis of their utilisation of the system. Where we become concerned is with the principle that only some generation users would be liable for a further charge that is intended to reflect the investment cost associated with adding a megawatt of generation at a specific location. We do not agree that such a charge is consistent with the development of the transmission business or is consistent with the facilitation of competition.

Underlying our concern is the question of how this generation user with short term access is treated by transmission system planners. Do the transmission system planners assume that the user is not there? If so, does this mean no transmission capacity is provided for and there is no expectation of generation export? What does this mean for security of supply, and future investment signals to generation and networks? What about if an existing generation user decides to transfer from long term to short term access – what happens to the existing transmission investment and the locational signal? If the locational signal is negative, why would a generation user forfeit this payment and would this result in over-investment in the regional transmission system?

In summary, we believe that further consideration is required on this issue and would again urge a holistic view in the development of the TNUoS charging methodology.

GB ECM-15
Long term fixed TNUoS tariffs

It is the instability, uncertainty and unpredictability of the current TNUoS charging methodology that results in generator users seeking the option to fix their tariffs. Equally, it is the instability, uncertainty and unpredictability of the current TNUoS charging methodology that results in the remaining users on variable tariffs being unwilling to be exposed to the financial consequences arising from differences between fixed and variable tariffs.

The option of long term fixed TNUoS tariffs based on the current methodology is always going to be difficult and, in our opinion, it is nigh impossible to achieve an acceptable allocation of the risks. Hence, we believe that the issue of instability, uncertainty and unpredictability should be addressed at source through a change to the charging methodology that provides stable, certain and predictable charges.

GB ECM-17

Transmission charging – a new approach

We support the proposal put forward by the Scottish Government, within the framework of a generator only local asset charge and wider shared asset charge (as described above).

SCOTTISHPOWER
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21 November 2008

Dear Patrick,

Response to the Charging Pre-Consultation Document
GB ECM-14 Consequential impact of CUSC amendment proposals CAP161 – CAP164

Thank you for the opportunity to respond to this Consultation Document. This response is submitted on behalf of ScottishPower Energy Management Ltd, ScottishPower Generation Ltd and ScottishPower Renewable Energy Ltd.

This pre-consultation and the other charging consultations underway in relation to the Transmission Access Review (TAR) highlight the additional complexity that requires to be introduced to the already highly complex transmission charging methodology in order to achieve the aims of TAR. This level of complexity being faced by generators will reduce the take-up of TAR products and adversely impact on the achievement of the aims of TAR and the Government's objectives.

We believe the opportunity should be taken now to simplify the charging methodology and the modifications necessary to implement CAPs 161, 162, 163 and 164.

A uniform transmission charge levied on all generation users of the GB transmission system on a half-hourly metered generation basis (£/MWh) would better facilitate competition as it would be more predictable and stable and could set the charge for entry capacity sharing and connect & manage and also set the minimum charge for short-term access rights and entry overrun. It would also recognise that the major new developments in transmission businesses are those required to ensure environmentally beneficial generation can access the network rather than to satisfy peak demand and move charging onto an overall usage basis rather than a potential peak usage basis. Generators could be incentivised to locate economically and efficiently through the proposed new charge for local generation assets.

I hope you find these comments useful. Should you have any queries on the points raised, please feel free to contact us.

Yours sincerely,

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Specific areas for comment

CAP 161 SO Release of Short-term access

Q1 Should the process for SO Release auctions afford more protection to third parties (general BSUoS payers) ?

In common with all the TAR proposals (CAP161 – 164) a balance has to be struck between cost reflective charging and reasonable socialisation of costs through BSUoS. An overly pessimistic view of outage and constraint risks by the system operator will result in unjustifiably high prices for the SO Release product thus restricting its use by users.

Q2 Should the process for calculating CLDTEC afford more protection to third parties (general BSUoS payers) ?

We believe that the process for calculating CLDTEC as discussed in the CAP161 working group report provides adequate protection to third parties. Under the SO Incentive Scheme, National grid will be incentivised to ensure that the costs of releasing additional capacity through CLDTEC do not exceed the revenues raised.

Q3 Do you think the auction process should run overnight and / or weekends?

We believe that it would be more efficient for the industry as a whole to have the auction process run overnight thus allowing users an additional working day to ascertain their plant position (including renewable plant) before submitting bids for short-term access. We do not see a requirement for weekend working unless activity should justify it at a later date.

Q4 Would you use an SO release product, and if so which aspects are appealing and which are concerning?

We are unlikely to use the SO release product as it does not offer sufficient certainty of price and availability to be “bankable” for new projects or predictable for existing power stations.

Q5 National Grid welcomes views on the approach (commoditisation based on MWh usage) to revenue recovery if a form of SO Release is implemented prior to revised residual changing arrangements being implemented, and welcomes other alternative options.

ScottishPower supports the commoditisation of the residual element of the Use of System charge (based on MWh usage).

CAP 162 Entry Overrun

Q6 Which is you preferred charging model and why?
In common with all the TAR proposals (CAP161 – 164) a balance has to be struck between cost reflective charging and reasonable socialisation of costs. An overly complex, less transparent and unpredictable methodology will deter users from making use of the products offered and thwart the aims of the Transmission Access Review. Although none of the models are ideal, our preference is for the Simple model for the reasons outlined below:

a) Simple Methodology

The Simple Methodology offers the closest approximation to ex-ante predictability through its use of pre-published scalars. However, the unpredictability of [BSUoS – RCRC] on a settlement period to period basis maintains a significant level of uncertainty for Users and would make the product unattractive. In addition, the use of scalars based upon historic constraint data may lead to counter-intuitive charging in periods where the current years' constraint incidence varies significantly from previous years. While providing a reasonable proxy for overrun costs averaged over a longer period (e.g. a year) the Simple Methodology may not facilitate efficient economic decisions to be made in the very short-term (i.e. whether to run in the next settlement period when short-term transmission access has not been secured by other means).

b) Cost Recovery Methodology
The Cost Recovery Methodology (CRM) charges overrun wholly upon ex-post information and is thus lacking in predictability. Although the methodology to be used by National Grid in apportioning costs to the overrunning party will be codified and thus transparent, it will be outwith the ability of most users to either repeat the calculation or predict future costs. The IT systems to automate the calculation of overrun charges will be costly and a cost benefit analysis should be carried out before embarking on major investment in systems.

c) Marginal Methodology
The Marginal Methodology discussed in the Working Group Report is too complex and lacks the transparency and predictability to enable Users to make informed economic decisions about whether to secure long-term or alternative short-term access products or whether to utilise overrun. This methodology would be expensive and slow to implement and would do little to achieve the objectives of TAR.

Q7 Under the simple methodology do you think the Scalar should be calculated by Volume or Settlement Period weighting and why?

We agree that volume weighting would be more appropriate as it would reflect that the actual overrun will be charged on the basis of the volume of overrun (MWh) in the period and not the excess capacity (MW) utilised.

Q8 Do you think the charge for overrun should be set at an asset based charge derived from TNUoS?

Overrun is charged where there has been insufficient investment in the wider transmission network to provide the required long-term firm access to the generator. It would therefore be inappropriate to make an asset based charge for wider access where the wider assets have not been provided. The generator should be liable for the local TNUoS charge for the assets provided to connect them to the wider transmission network.

Q9 Would you consider using Overrun, and if so which aspects are appealing and which are concerning?

We would be unlikely to use the overrun product as it does not provide sufficient price certainty to enable economic decisions to be made on future generation developments or on the planned running of existing stations. However, it does provide a commercial alternative to breach of the CUSC and is thus a facilitating measure when used alongside SO release, sharing and other short-term trading products.

Q10 Do you think the Simple Methodology (Option 1) should differentiate import and export?

Q11 Do you think that the Cost Recovery Methodology (Option 2) should be developed to include negative charges, if so which variant?

The additional complexity of attempting to calculate negative overrun charges should be avoided and would not merit the additional cost of systems required for their calculation.

Q12 Do you consider the simple methodology would be a reasonable default mechanism?

Of the three methodologies considered, we consider the simple methodology to be the most appropriate both as a default and long-term mechanism.

Q13 Should the Simple Methodology include negative prices?

The additional complexity of attempting to calculate negative overrun charges should be avoided and would not merit the additional cost of systems required for their calculation.

Q14 Under a nodal model, how should the zones for simple and Cost Recovery tariffs be constructed: Operational Zones, daily (not for simple) or TNUoS based?

To improve predictability overrun zones should be determined annually ex-ante and should be based upon Operational Zones which represent the constraint boundaries expected during the forthcoming year based upon the analysis work included in the Seven Year Statement. TNUoS zones are not representative of the likely occurrence of constraints.

Q15 National Grid is interested in respondents views on whether the Marginal Methodology should produce zonal or a nodal Overrun tariffs?

ScottishPower does not support the use of the Marginal Methodology on either a zonal or a nodal basis due to its complexity and lack of transparency and predictability.

CAP 163 Entry Capacity sharing

Q17 Would you consider sharing access, and if so which aspects are appealing and which are concerning?

ScottishPower supports the introduction of entry capacity sharing and would be willing to use sharing where adequate nodal exchange rates were offered between sharing power stations for sufficiently long periods of time. We have concerns that there may be an adverse interaction between the length of time for which the sharing arrangement is requested by parties and the nodal exchange rate offered by the system operator. Sharing arrangements need to be long enough to be “bankable” by users unable to secure alternative firm access in the same period. Our concern is that given a longer time frame, the system operator will factor in greater risks thus reducing the nodal exchange rate.

Nodal exchange rates must be provided ex-ante. Any proposal incorporating ex-post determination of exchange rates would not be "bankable".

CAP 164 Connect and manage

Q18 Do you think an asset based charge is appropriate and what is your rationale?

We do not believe that an asset based charge is appropriate for Connect & Manage users as the associated wider infrastructure will not have been delivered by the relevant Transmission Owners. Connect & Manage users should pay the local element of the TNUoS charge for their local connection assets but should not be liable for either the wider or residual element of the TNUoS charge. However, in the interests of simplicity, we would prepared to see Connect & Manage users pay the wider TNUoS charge as a "proxy" cost to avoid the requirement more complex ex-post charging arrangements which would not be "bankable".

Q19 Do you think the TNUoS calculation should be amended to over recover and then channel this revenue in to BSUoS to partially offset the increase in BSUoS?

ScottishPower believes that the additional revenues from the connection of Connect & Manage users should be ring-fenced from TNUoS receipts and used to offset any potential increase in BSUoS costs.

Q20 Would you apply for early connection, and if so for what volume, number of years advancement of your project this represents and what SYS zone is the project in?

As a major developer of both renewable and thermal generation projects, ScottishPower would apply for early connection of its generation projects in line with the early connection dates indicated in the quarterly reports submitted under the relevant Construction Agreements.

In summary, the amount of generation likely to advance would be as follows;

SYS Zone	No of Projects	Capacity (MW)	Current Connection Date	Anticipated Connection Date
Z1	1	53	Post 2018	2012
Z4	4	168	2011	2010
Z4	1	69	Post 2018	2010
Z9	1	500	Post 2018	2011 - 2014
Z13	1	60	2011	2010
Z13	1	78	2014	2013
Z15	1	493	2019	2016
Z15	1	493	2022	2017

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21st November 2008

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Pre-Consultation Document GB ECM-17

Charging Pre-Consultation Document GB ECM-14 Consequential impact of CUSC amendment proposals: CAP161 Transmission Access – System Operator Release of Short-term Entry Rights, CAP162 Transmission Access – Entry Overrun, CAP163 Transmission Access – Entry Capacity Sharing, CAP164 Transmission Access – Connect and Manage.

Dear Patrick

Thank you for the opportunity to comment on the Charging Pre-Consultation Document GB ECM-14 Consequential impact of CUSC amendment proposals: CAP161 Transmission Access – System Operator Release of Short-term Entry Rights, CAP162 Transmission Access – Entry Overrun, CAP163 Transmission Access – Entry Capacity Sharing, CAP164 Transmission Access – Connect and Manage (GB ECM14). This response is provided on behalf of the RWE group of companies, including RWE Npower plc, RWE Supply and Trading GmbH and RWE Innogy.

We believe that the charging arrangements are integral to the effectiveness of each of the CUSC amendment proposals individually and also collectively. We believe that a wide ranging review of the charging proposals in the context of the CUSC reforms is required in order to understand the implications of the changes. This should, for example consider over and under recovery arrangements which may be required in the context of each amendment proposal.

We note that the proposed changes all have differing implications to a greater and lesser extent for charges and revenue adequacy. The extent to which that the changes may introduce enhanced volatility of charging, particularly in relation to the proposed residual charging regime, requires further consideration.

With regard to CAP164, Transmission Access – Connect and Manage, we believe

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that a cost reflective charge should be introduced. A simple (Overrun) methodology developed for CAP162 where X*(BSUoS-RCRC) in a particular zone for any half hour period could be used as an interim proxy for constraint costs under a connect and manage regime in order to provide an approximate targeting of these costs on users that have caused them. However, our preference is for a marginal methodology which would seem to offer the most economic and efficient outcome in relation to the efficient costs of short-term access at various locations on the transmission system if CAP164 were to be implemented.

Our comments with regard to charging for each of the amendment proposals are enclosed.

If you wish to discuss any aspect of our response, please do not hesitate to contact me.

Yours sincerely

By email

Bill Reed,
Market Development Manager

Attachment

Attachment: Charging Pre-Consultation Document GB ECM-14 Consequential impact of CUSC amendment proposals comments on specific amendment proposals.

CAP161 Transmission Access – System Operator Release of Short-term Entry Rights

We support National grid's conclusions that no specific changes to the charging methodologies are required to accommodate CAP161. However, we note that in the case of C-LDTEC there may be implications for revenue adequacy and that an appropriate over- and under recovery methodology will be required to facilitate its implementation. We believe that further work is required to identify whether such over and under recovery is targeted at those users that use the short term C-LDTEC product (since they have cause the over or under recovery) of are recovered across all users.

CAP162 Transmission Access – Entry Overrun

Entry Overrun should allow more generation to connect to the GBTS and hence increase competition provided that the overrun prices include any additional constraint costs incurred in operating the system. Also users should have a reasonably clear idea of what these additional costs might be before they decide to overrun in any particular period. The proposed simple (Overrun) methodology using (BSUoS-RCRC) multiplied by a scalar (X) that reflects constraint costs as a proxy for constraint costs in any half-hour period could provide an appropriate solution, at least as an interim (temporary) solution, as it does give some approximation to what potential "system" costs might be in a particular zone at a particular time.

Our preference is for a nodal marginal methodology which would seem to offer the most appropriate outcome in relation to the efficient costs of short-term access at various locations on the GBTS. If the marginal methodology was available to users then it may be possible for them to make a reasonable forecast of the costs for short-term access at various locations on the system. Alternatively, the GBSO could release its forecasts of these costs at the day-ahead stage so that users could make an economic judgement whether to overrun at a particular location. However we note that a marginal methodology may not be available for an April 2010 implementation date and an interim, perhaps based on the simple methodology, may be required.

We do not support the Cost Recovery Methodology as it would be very difficult to identify exactly which costs were attributable to overrunning parties and there would inevitably be a degree of subjectivity in disaggregating these costs. This model may be expensive to administer and may not help users at different locations to easily predict potential Overrun prices at any particular time or location.

CAP163 Transmission Access – Entry Capacity Sharing

We believe that are no specific changes to the charging arrangements to accommodate entry capacity sharing. However, we note that National grid consider that there may be need for a new charge "for general sharing where access paid for by one user is passed to another user with not increase in costs". We are unclear as to the nature of such a charge (e.g. capacity based or commodity base) and indeed the rationale for the charge since the exchange rates should be designed to ensure that capacity sharing has no impact on other any other user.

CAP164 Transmission Access – Connect and Manage.

It is recognised that CAP164 in its current form will allow more generation to be connected to the GB Transmission System before the necessary wider system reinforcements can be made by the Transmission Owners. This will lead to an increase in system constraint costs, which under CAP164 will be socialised and paid by all BSUoS payers. This means that the true costs of connection at specific points on the GB Transmission System are not being seen by those parties connecting under Connect & Manage (i.e. the investment costs of the necessary system reinforcement are not discovered as the required investment cannot be made due to delays in gaining the necessary planning consents and other issues).

Consequently, we can only offer our support for Connect and Manage on condition that any resultant increases in constraint costs are either allocated to parties causing them. Parties adding to existing constraints would be expected to pay more for their connection than those connecting in more favourable zones where constraint payments are likely to be smaller.
Failure to do this would give inappropriate incentives and, over time, lead to an increasingly inefficient grid access regime.

We believe that a full marginal cost methodology solution in the long term should be implemented, but due to the short implementation timescales for CAP164, a Simple Cost Model could be used in the interim period. A Simple Cost Model (SCM) has been derived for CAP162, and levies an appropriate charge for Parties who output in excess of their short and long term access to the transmission system. The SCM calculates constraint costs based on X*BSUoS - RCRC (where X is a multiple or “Scalar”). The Scalar X would be calculated on a zonal basis, based on historic constraint costs and published before the start of each financial year so that Parties could estimate the likely costs of connecting in specific areas of the GB Transmission System. We would support the introduction of a cost reflective charge as an amendment to the current charging consultation.

A cost reflective charge would ensure, the efficient discharge by the licensee of the obligations imposed upon it under the Acts and by the licence, and facilitating effective competition in generation and, promoting the more efficient use of the transmission system through facilitating connection in advance of wider transmission works. It would also improve the signals for design of the transmission system by ensuring that only projects that are likely to connect within a defined timescales actually apply for connection.

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13th November 2008

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Dear Mr Hynes,

ECM 14 – Charging pre consultation on CAP 161-164

Thank you very much for the opportunity to respond to the charging pre consultation on CAP 161-164.

Biffa is a leading integrated waste management business in the UK, which operates across the breadth of the waste management value chain. It provides waste collection, treatment and recycling, and disposal services to around 75,000 local and national customers in the industrial, commercial and municipal sectors and has a turnover of over £770 million per annum. Biffa is a significant provider of renewable energy in the UK with interests in approximately 109MW of installed capacity.

Please find below Biffa's responses to the charging pre consultation.

Cap 161 SO Release of Short-term access

Q1 Should the process for SO Release auctions afford more protection to third parties (general BSUoS payers)?

Third parties should not require any further protection as they should be better off as a result of SO release auctions. The NGC should have appropriate arrangements to share any BSUoS decrease or increase and this should afford further reassurance to BSUoS payers.

Q2 Should the process for calculating CLDTEC afford more protection to third parties (general BSUoS payers)?

Protection should be provided through the margin NGC builds into its estimate of the cost of access provision.

Q3 Do you think the auction process should run overnight and / or weekends?

Biffa have no objections to auctions being run overnight or at weekends.

Q4 Would you use an SO release product, and if so which aspect are appealing and which are concerning?

No comment.

Q5 National Grid welcomes views on the approach (commoditisation based on MWh usage) to revenue recovery if a form of SO Release is implemented prior to revised residual changing arrangements being implemented, and welcomes other alternative options.

MWh usage is appropriate, but not to recover the whole residual TNUoS charge where considerable amounts have been paid to release additional capacity.

Cap162 Entry Overrun

Q6 Which is you preferred charging model and why?

The cost recovery methodology is preferable, as it will leave other BSUoS payers neutral and would no more difficult to implement than the simple methodology.

Q7 Under the simple methodology do you think the Scalar should be calculated by Volume or Settlement Period weighting and why?

No comment.

Q8 Do you think the charge for overrun should be set at an asset based charge derived from TNUoS?

It should be related to the cost of short run provision of access.

Q9 Would you consider using Overrun, and if so which aspects are appealing and which are concerning?

Biffa would prefer to use more predictable TNUoS charges.

Q10 Do you think the Simple Methodology (Option 1) should differentiate import and export?

Yes.

Q11 Do you think that the Cost Recovery Methodology (Option 2) should be developed to include negative charges, if so which variant?

No, as this will increase complexity.

Q12 Do you consider the simple methodology would be a reasonable default mechanism?

Yes if necessary, but Biffa do not believe that it would involve less work to implement that the cost recovery method.

Q13 Should the Simple Methodology include negative prices?

No, as this will increase complexity.

Q14 Under a nodal model, how should the zones for simple and Cost Recovery tariffs be constructed: Operational Zones, daily (not for simple) or TNUoS based?

Operational zones are preferable.

Q15 National Grid is interested in respondents views on whether the Marginal Methodology should produce zonal or a nodal Overrun tariffs?

Nodal Overrun tariffs would be most appropriate if the Marginal Methodology was implemented.

CAP163 Entry Capacity sharing

Q17 Would you consider sharing access, and if so which aspects are appealing and which are concerning?

No.

Cap164 Connect and manage

Q18 Do you think an asset based charge is appropriate and what is your rationale?

The basis of CAP 164 is that generators should be committed to paying TNUoS charges and obtain the firm access that is associated with this. Although CAP 164 generators should pay a charge equal to the TNUoS charge for their location, we do not believe that this income should be paid to Transmission owners, prior to the appropriate expenditure on infrastructure having been incurred.

Q19 Do you think the TNUoS calculation should be amended to over recover and then channel this revenue in to BSUoS to partially offset the increase in BSUoS?

Yes.

Q20 Would you apply for early connection, and if so for what volume, number of years advancement of your project this represents and what SYS zone is the project in?

No comment.

If there are any points on which we can provide additional specific clarification, please do not hesitate to contact us,

Yours sincerely,

Ben Rigg.

Ben Rigg

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21 November, 2008

Dear Patrick,

Charging Pre-Consultation: GBECM-14 Consequential Impact of CUSC amendment proposals CAP161 to 164

Thank you for the opportunity to respond to the above consultation. This response is made on behalf of E.ON UK. Our answers to the specific questions posed in the pre consultation are as follows.

Cap 161 SO Release of Short-term access

We believe that the proposed short term capacity release mechanism is likely to be a secondary product and will not for most developers provide an alternative to long term rights. Most developers would not wish to commit to building a new power station and rely on being successful in the short term release mechanism. Therefore, we believe that long term rights will continue to be the primary source of access for generators. However, as supplementary product for short periods of running short term access rights may prove useful. For instance, existing low load factor generation may seek to acquire access from this mechanism which could free up long term rights for new entrants.

With this in mind we believe that a main aim should be to keep the solution as simple as possible. This means that complex and expensive design and implementation choices should be avoided and a solution should be adopted that is suitable at first to cope with a low level of applications for short term products but that can evolve to deal with increased demand should it arise.

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Q1 Should the process for SO Release auctions afford more protection to third parties (general BSUoS payers)?

The process for SO release auctions should aim to keep general BSUoS payers whole to the decision to release shorter term capacity. Therefore, the assessment of possible costs should be carried out accordingly and an appropriate safety margin should be built into the figure derived in order to achieve this. There are two potentially offsetting effects to consider in this respect, when comparing the five week ahead and the two day ahead processes. The five week ahead process will be carried out further away from real time so there is a greater risk that circumstances will change from those predicted. However, the two day ahead process gives less time to National Grid to assess the level of cost, so this may be less thorough. On balance it is difficult to see which would result in more accurate cost estimates.

Q2 Should the process for calculating CLDTEC afford more protection to third parties (general BSUoS payers)?

As with our response to Q2, we believe that the process CLDTEC should aim to keep general BSUoS payers whole to the effects of the decision to release shorter term capacity. Therefore, the assessment of possible costs should be carried out accordingly in order to achieve this. The further out from real time this assessment is carried out the higher the risk that it will be wrong and that BSUoS payers will be exposed to additional costs. Therefore, a higher safety margin should be built in the further out the estimate is made.

With SO release there is an expectation that a profit margin will normally be achieved as successful applicants have to pay their bid, which should be equal to or higher than the expected cost in order to trigger release of the product. This profit margin would buffer general BSUoS payers from errors in the estimate of constraint costs. A safety margin is more important for the assessment of CLDTEC applications, as the product will be priced at the level of estimated costs and would therefore not generate any such profit margin.

Q3 Do you think the auction process should run overnight and/or weekends?

We do not believe that the auction process should run overnight or on weekends if this has significant implementation and operational cost implications. Instead, focus should be on implementing the simplest solution that would be of use to generators and adapt this in due course if there is sufficient demand.

Q4 Would you use an SO release product, and if so which aspects are appealing and which are concerning?

We would consider using any products that were implemented, although that doesn’t necessarily mean that we would support all products. We are not supportive of CLDTEC as it looks to be of a higher risk to general BSUoS payers.

Q5 National Grid welcomes views on the approach (commoditisation based on MWh usage) to revenue recovery if a form of SO Release is implemented prior to revised residual changing arrangements being implemented, and welcomes other alternative options.

This is a sensible proposal in principle to ensure that generators using shorter term release capacity do not free ride on costs that should be shared by all users of the transmission system. However, we believe that there are two practical issues that need to be addressed. Firstly, it is not clear the proportion of total costs that should be recovered from short term release generators as a class. Secondly, we are uncertain as to the level of take up that should be assumed in order to convert these costs into a unit charge to be applied in the assessment of SO release applications. However, given that this is to be a temporary solution it may be worth taking a view on these two elements and accepting the risk associated with this in order to achieve an earlier implementation of the product.

Cap162 Entry Overrun

Q6 Which is your preferred charging model and why?

As we do not expect overrun to be used by generators as a formal access product in its own right we believe that the take up of overrun will be somewhat limited. Of course, this depends on how attractive a product it is to use. Therefore, the price and risk associated with overrun is an important consideration. A main aim of overrun pricing must be to keep other Users whole from the effects caused by the overrunning party. Therefore, a cost reflective approach which aims to recover the costs caused by the overrunning generator is important.

We believe that the marginal approach that has been put forward is unlikely to meet this objective. Of course, the model is at an early stage of development and testing and it is difficult to conclude too much with a great deal of certainty. However, this approach to charging sets out specifically not to recover costs, but to send a marginal signal. We therefore are not supportive of this option at present. Also as indicated in the consultation document, the marginal pricing model is likely to require considerable development resource. We would question whether a facilitating product such as overrun with a limited expected take up should at this stage demand such intensive use of resource.

In addition to seeking to charge on a cost reflective basis, overrun should be a useable product for generators. Therefore, generators should be able to assess the likely effect that overrunning will have on their charges. The cost recovery model will by its subjective and retrospective nature (requiring ex post judgements from operators at National Grid as to why certain actions were taken) prove more difficult for generators to use.

The Simple method may not be fully accurate for all circumstances, but it does have the aim of cost recovery as the basis of its derivation. As such, it could be deemed as a reasonable pre estimate of the costs associated with overrun. In this context it could be considered to be setting liquidated damages associated with overrun. It is likely to be more useable by generators as they will at least know up front what multiplier, or scalar, will be used and can take a view on the possible level of BSUoS minus RCRC to which it will be applied.

The Simple method is also likely to involve less development cost and operation costs that the other two models. The Marginal model, as we have mentioned above, is likely to involve a high degree of development cost for National Grid, whereas the manual assessments required for the Cost Recovery method should mean relatively high operational costs.

On balance therefore, we would give our initial support to the Simple model.

Q7 Under the simple methodology do you think the Scalar should be calculated by Volume or Settlement Period weighting and why?

Volume weighting would appear to be appropriate as the constraints not only have a cost, but a volume associated with them. Volume weighting would be equivalent to summing the total constraint costs for the zone and dividing them by the total volume of constraints in MWh. This would seem the most appropriate approach for calculating a £/MWh figure for the zone.

Q8 Do you think the charge for overrun should be set at an asset based charge derived from TNUoS?

It would not seem appropriate to base overrun on a TNUoS based charge as the costs incurred as a result of allowing a generator to overrun are balancing costs which would otherwise be recovered through BSUoS.

Q9 Would you consider using Overrun, and if so which aspects are appealing and which are concerning?

We would consider using overrun. The benefits or otherwise of the charging options are outlined in our response to Q6.

Q10 Do you think the Simple Methodology (Option 1) should differentiate import and export?

If there are zones that would be subject to import and export constraints then it would appear to be appropriate to produce scalars for both circumstances, as long as the cost reflectivity of the scalars is not significantly compromised as a consequence.

Q11 Do you think that the Cost Recovery Methodology (Option 2) should be developed to include negative charges, if so which variant?

If it is deemed appropriate to have negative prices as a general principle then this should not be dependent on the methodology chosen. In terms of the most appropriate method for determining the level of charge, the second variant (B) would seem to be an appropriate compromise between accuracy and operational cost.

Q12 Do you consider the simple methodology would be a reasonable default mechanism?

The simple methodology would be a reasonable main methodology so we also believe that it would be a suitable default mechanism.

Q13 Should the Simple Methodology include negative prices?

As with our answer to Q11 if it is deemed appropriate to have negative prices as a general principle then this should not be dependent on the methodology chosen. The simple approach should be open to adaptation to provide negative prices for overrun that reflect the average constraint costs in the zones concerned.

Q14 Under a nodal model, how should the zones for simple and Cost Recovery tariffs be constructed: Operational Zones, daily (not for simple) or TNUoS based?

There is no specific rationale to link these zones with TNUoS zones that serve a different purpose. The zones should be chosen on the basis of maximising the accuracy and stability of the relevant scalars and facilitating their efficient production.

Q15 National Grid is interested in respondents views on whether the Marginal Methodology should produce zonal or a nodal Overrun tariffs?

We are not yet fully convinced of the ability of the marginal model to provide appropriate charges. However, should it be implemented then there would appear to be no reason why a zonal approach similar to that for the other methodologies could not be adopted for overrun.

CAP163 Entry Capacity sharing

Q17 Would you consider sharing access, and if so which aspects are appealing and which are concerning?

We would consider sharing in appropriate circumstances. Ideally, this would have been possible on a zonal basis with a one to one exchange rate. However, given the limitations surrounding setting zones then a nodal approach with an exchange rate associated with it is still a useful option to have. Clearly, there are risks associated with setting exchange rates in that any inaccuracies will have wider balancing cost implications. Otherwise, the direct implications on charges are minimal.

Cap164 Connect and Manage

Q18 Do you think an asset based charge is appropriate and what is your rationale?

A TNUoS based charge for connect and manage generators would not be appropriate. Instead, they should be exposed to costs similar to those calculated for overrun whilst wider infrastructure has not been built to accommodate them. Of course, they should also be subject to the relevant local and residual charge.

Q19 Do you think the TNUoS calculation should be amended to over recover and then channel this revenue in to BSUoS to partially offset the increase in BSUoS?

This would be inappropriate and problematic not least because the different charges are recovered from demand and generation users in different proportions. A more appropriate solution would be to target the additional balancing costs caused at the relevant generators.

Q20 Would you apply for early connection, and if so for what volume, number of years advancement of your project this represents and what SYS zone is the project in?

Although we do not support a socialised connect and manage approach, one that targeted costs accurately would be more attractive. However, if either was implemented, then we would consider using it. We would be effectively subsidising other parties' use of a socialised product so we might as well receive some benefit as well. We could not at this time commit to stating which projects we would seek to bring forward.

I hope the above comments prove helpful.

Yours sincerely

Paul Jones
Trading Arrangements

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14th November 2008

Dear Patrick,

Response to ECM 14 – Charging pre consultation on CAP 161-164

The Renewable Energy Association is pleased to be able to offer its comments on the pre consultation to the charging modifications associated with CAPs 161 to 164. As you are aware our members work on all types of renewable power and heat projects and obtaining more timely access to the transmission system is one of the key issues that if achieved would help our aim and that of the Government of reducing CO_2 emissions. The charging modifications associated with the proposed CUSC changes are often as important as the CUSC changes themselves.

As a general principle the REA has consistently been in favour of cost-reflective charging. There is one overarching issue which covers more than one of the proposals and we would like to flag up at the outset, without prejudicing any response that we may make to the consultation on the recovery of residual TNUoS charges from generators:-

It is that it is not clear that in cases where a generator is making a potentially substantial short-term cost-related payment, for example an overrun charge or a SO release payment (which is essentially an overrun charge fixed in advance), it is cost reflective to charge the full residual element of TNUoS charges.

It is clear that of the components as envisaged of TNUoS:

1. The locational charges which are based on the marginal cost of additional injection at a node and are directly related to the reinforcement cost to accommodate that additional injection. They should therefore not be charged for access products that are not intended to precipitate any investment in the transmission system or to give system wide access rights to a generator.

2. The charge for the local network should be payable by all generators that have the option of transmission access as that local network has been built for all such generators.

It is not however at all clear in what circumstances it is appropriate to charge all of the residual element of TNUoS charges, which recover all remaining costs of the transmission system, from parties that are paying substantial amounts in respect of overrun charges and / or SO release fees. It is clear of course that such parties should pay any residual associated with the provision of the local network. It is also clear that in cases where there is a zero overrun charge or a zero cost capacity release equity considerations would dictate that they should pay the full residual charge as they are enjoying the same access to the transmission network as parties that have purchased long term rights. It seems however that in cases where there is a substantial short term charge they are not getting the same benefit from historical investment as other users and they should not therefore be charged the same residual charge as those users. We will address this issue specifically in our response to the charging pre consultation on generator residual charging.

With this guiding principle we now address the charging proposals for each of the modifications.

Cap 161 SO Release of Short-term access

Q1 Should the process for SO Release auctions afford more protection to third parties (general BSUoS payers) ?

Overall third parties should be better off as a result of SO release auctions and therefore do not require any further protection. In order to be accepted, generators' bids will have to be at least equal to NGC's estimate of the cost of the release. They will therefore generally be in excess of the estimated cost and BSUoS payers will be better off as a result of their acceptance. For marginal decisions where a generator has bid the exact cost that NGC has estimated as being incurred by the capacity release (assuming that NGC has not built a safety margin into this estimate) the outcome for third parties will depend entirely on whether NGC's estimate turns out to be lower or higher than the outturn. We do not see why there should be any systematic bias in this and therefore the cases where it turns out to be too low should be balanced over time by those where it turns out to be too high. Of course for the bids accepted that were higher than NGC's estimate there is a probability that the estimate turns out to be so low that the outturn is more than the accepted bid. As the bid was higher than the estimate and there is no bias (as argued above) we would expect that overall general BSUoS payers should benefit from the exercise. It would be expected that NGC would have appropriate incentive arrangements to share in any BSUoS decrease (or increase) and this should provide further comfort for BSUoS payers.

Q2 Should the process for calculating CLDTEC afford more protection to third [parties (general BSUoS payers)?

The comments above are broadly applicable except that NGC offers a price (its estimate of the cost of the release) which may be accepted or not. There is not therefore the safeguard due to the vast majority of access provided through this mechanism paying in excess of NGC's estimate of the cost of providing it. In addition prediction further ahead provides more uncertainty. The key therefore to providing protection to BSUoS payers on this will be how much margin NGC builds into its estimate of the cost of providing the access.

Q3 Do you think the auction process should run overnight and / or weekends?

We responded to this in respect of the CUSC modification itself and said that we were in favour of weekend auctions but that whether running the auctions overnight was justified was a pragmatic matter which we had no strong views on.

Q4 Would you use an SO release product, and if so which aspect are appealing and which are concerning?

We cannot answer this question on our members' behalf, although we anticipate most interest to come from well established power stations.

Q5 National Grid welcomes views on the approach (commoditisation based on MWh usage) to revenue recovery if a form of SO Release is implemented prior to revised residual changing arrangements being implemented, and welcomes other alternative options.

To the extent that it is appropriate to recover the residual charge we would be in favour of MWh usage but you should note that as expressed above we would not accept that it would be appropriate to recover the whole residual TNUoS charge where a substantial amount has been paid for the release of additional capacity.

Cap162 Entry Overrun

Q6 Which is you preferred charging model and why?

Our preference is the cost recovery methodology. It will leave other BSUoS payers neutral (or possibly a bit better off if negative overrun charging is not credited). The simple methodology is superficially easier to implement but in order to work out the factors the actual cost of constraints has to be calculated anyway so it is not clear that there is in fact any saving in work compared to the cost recovery methodology.

In terms of the simple methodology being more predictable, there may be some truth in this. In order to predict the simple overrun charge it is however necessary to predict BSUoS, RCRC and importantly whether the constraint will be switched on in a particular period. It is not therefore obvious that prediction will be significantly easier than for the simple methodology method. In order to use overrun (or an overrun-type of product) as a basis on which to build a new generation facility, it would have to be far more predictable than the simple methodology appears to be. Having said that, if for some reason there is a preference not to use the cost recovery methodology, then our second choice would be the simple methodology.

Our least favourite option is the marginal methodology, for a number of reasons. Leaving aside its volatility and the IT challenges to implement it, it does not recover the cost so as to leave other BSUoS payers whole. We do not accept the argument that a marginal methodology gives a level playing field decision as to whether to opt for long term or short term access. The only component of TNUoS charges that could be described as marginally based is the locational element, which makes up a minority proportion of the total charges. As we do not accept that a party paying an overrun charge should pay the full TNUoS residual it follows that some of the charge avoided by opting for short term access would be part of the TNUoS residual and therefore not marginal in nature. The calculation that a generator will make on whether to opt for overrun or long term access will largely be based on its predicted load factor. It is probably more important that the overrun charges are on the same basis as SO release costs, which will be implicitly based on a total i.e. average cost. For these reasons the marginal methodology is our last choice and, irrespective of IT complexity, has no advantages and considerable disadvantages compared to the average cost methodology.

Q7 Under the simple methodology do you think the Scalar should be calculated by Volume or Settlement Period weighting and why?

Although we do not have strong views on this, volume weighting appears to give appropriate weight to settlement periods when the volume and cost of the constraint is greatest, which seems appropriate.

Q8 Do you think the charge for overrun should be set at an asset based charge derived from TNUoS?

In terms of overrun as a product it ought to be related to the short run cost of providing access. Having said that if the product were to be contemplated as a primary means of providing access to new projects (which it is currently not by most observers) there would be merit in having a “fixed” overrun charge arrangement which it might be convenient to base on TNUoS charges. Note this is a completely different issue to that dealt with by question 19.

Q9 Would you consider using Overrun, and if so which aspects are appealing and which are concerning?

Again, this is a question for individual members of the REA. Having said that we do not regard overrun charges (which are less predictable than say TNUoS charges) as being suitable for the primary access arrangements for new plant. Overrun is, however, a very important product for providing contestability with other options as well as catering for marginal capacity.

Q10 Do you think the Simple Methodology (Option 1) should differentiate import and export?

Yes

Q11 Do you think that the Cost Recovery Methodology (Option 2) should be developed to include negative charges, if so which variant?

We do not think that it is necessary to develop negative overrun charges. It is unlikely that parties will overrun frequently where they reduce constraint costs and if they do they may have an opportunity to obtain some payment via the balancing mechanism. Introducing negative overrun charges adds an extra dimension of complexity and we think that pragmatically if it does happen without money being obtained through an accepted offer in the balancing mechanism, it should just be regarded as a bonus for the generality of BSUoS payers.

Q12 Do you consider the simple methodology would be a reasonable default mechanism?

Yes, if necessary. However as stated earlier, we are not convinced that it easier to implement or has other advantages over the cost recovery method.

Q13 Should the Simple Methodology include negative prices?

No, for similar reasons to those given in response to question 11.

Q14 Under a nodal model, how should the zones for simple and Cost Recovery tariffs be constructed: Operational Zones, daily (not for simple) or TNUoS based?

We would favour actual operational zones as being more cost reflective.

Q15 National Grid is interested in respondents views on whether the Marginal Methodology should produce zonal or a nodal Overrun tariffs?

We do not favour this methodology. However if it were introduced in order to provide marginal signals, it would make sense for these to be as accurate as possible. This would suggest using nodal overrun prices.

CAP163 Entry Capacity sharing

Q17 Would you consider sharing access, and if so which aspects are appealing and which are concerning?

It is natural that variable plant such as wind would share capacity with low load factor controllable plant that would not expect to run when it was windy. In these circumstances we would expect the wind plant to have the primary TEC but to be very keen to share that with a complementary type of plant.

Cap164 Connect and manage

We feel that there are a number of issues associated with charging if CAP 164 is approved that have not yet been extensively discussed. These include:

1. For the period before there has been wider infrastructure reinforcement but after a CAP 164 generator has connected, should that generator be taken into account in the charging model i.e. should its presence influence locational differentials?

2. For the above period, should revenue received from the generator affect the overall level of TNUoS charges collected from “non CAP 164” generators?

We think that the arguments for issue 1 above are quite finely balanced. There is the argument that including additional generation in an exporting area without the corresponding infrastructure reinforcement produces unduly high locational variation. On the other hand one could argue that an exceptionally strong signal is appropriate when additional generation is connecting to an area in advance of infrastructure reinforcement.

In terms of contribution to the total TNUoS revenue pot, we assume that the pot is set at a level that covers the allowed costs for the actual transmission system and that CAP 164 generators contribute to the cost of the local network plus any deeper infrastructure that has actually been constructed. We will also assume that the demand / generator payment ratio remains unchanged. The question is whether further “TNUoS” money from the CAP 164 generators should go into the TNUoS pot to reduce the TNUoS payment made by other generators in total from what they would have been paying without the existence of the CAP 164 generators. We think not and expand on this in our answer to question 19. For the avoidance of doubt, as soon as all the necessary infrastructure has been built the CAP 164 generators become like any other generators and their full standard TNUoS payments should flow into the normal TNUoS pot.

Q18 Do you think an asset based charge is appropriate and what is your rationale?

The basis of CAP 164 is that generators should be committed to paying TNUoS charges and obtain the firm access that is associated with this. As suggested below (and above) although CAP 164 generators should pay a charge equal to the TNUoS charge for their location, we do not believe that this income should all go into the

TNUoS pot i.e. be paid to Transmission owners, prior to the appropriate expenditure by the TOs on infrastructure having been incurred.

Q19 Do you think the TNUoS calculation should be amended to over recover and then channel this revenue in to BSUoS to partially offset the increase in BSUoS?

Yes. As CAP 164 generators are enjoying normal firm rights they should pay an amount equal to the standard TNUoS charges for their location. The TOs should however only be paid for the network that they have actually provided. As we do not think that overall the "TNUoS" revenue paid by CAP 164 generators should reduce the TNUoS payments of others, we think that the difference between the standard TNUoS amounts and that required to hold other generators in total whole in their TNUoS charges (i.e. pay for the additional network actually provided), should be channelled into the BSUoS pot to reduce any impact on BSUoS payments due to the generators connecting in advance of the provision of all the desired infrastructure.

Q20 Would you apply for early connection, and if so for what volume, number of years advancement of your project this represents and what SYS zone is the project in?

We expect that many of our members would connect earlier if permitted to.

Please let us know if you would like to discuss any aspects of this letter further.

Yours sincerely,

Gaynor Hartnell
Deputy Director