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Dear Richard,

**GB Transmission Charging: Final Methodologies Consultation
20 August 2004**

Thank you for the opportunity to respond to this consultation. This response is submitted on behalf of ScottishPower UK Division, which includes the UK energy businesses of ScottishPower, namely ScottishPower Energy Management Ltd, ScottishPower Generation Ltd and ScottishPower Energy Retail Ltd.

You will recall that we commissioned NERA to provide an expert report on GB transmission charging after publication of NGC's Initial Methodologies Consultation in April and this was subsequently submitted to and published by NGC. NERA has been further commissioned to provide a supplementary report in relation to this Final Methodologies Consultation and that is submitted with this response.

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

Yours sincerely,

Mike Harrison
Commercial Manager, Trading Arrangements
ScottishPower Energy Management Limited

EXECUTIVE SUMMARY

ScottishPower UK Division welcomes the opportunity to comment on NGC's proposed methodologies for GB transmission charging. We are concerned that NGC has declined to amend its proposals in light of arguments that we and other respondents have made, in response to NGC's earlier consultations on this issue. We are particularly disappointed that NGC has failed to provide an adequate response to the detailed criticism of its approach contained in the NERA¹ report of 26 July, which NGC has published.

We asked NERA to consider whether the views expressed by NGC or other respondents in the August consultation paper would cause NERA to alter the conclusions contained in its report of 26 July. NERA has considered the August consultation paper in detail and has confirmed that the principal conclusions of its 26 July report remain valid. NERA has prepared a supplementary report that addresses specifically the comments and issues raised by NGC in the August paper. We have provided a copy of the NERA supplementary report with this response.

With regard to the expansion factors and expansion constant adopted by NGC in its methodology, NGC has failed to provide either a satisfactory justification of its assumptions or any evidence to support them. On the basis of further analysis outlined in its supplementary report NERA has confirmed its conclusion that NGC overstates the cost of system expansion and hence the strength of locational charges by some 25% to 40%. If NGC were to adopt assumptions consistent with the analysis and evidence provided by NERA it would have a very significant impact on transmission charges, particularly for generators located in Scotland.

NGC confirmed in its August consultation paper that it intends to put more than one proposal for the GB charging methodology to Ofgem for consideration. However both Scenario A and B described in the August paper include assumptions which NGC has failed to justify. Against this background we believe that NGC must provide Ofgem with one or more additional scenarios incorporating assumptions that are more consistent with the analysis and evidence presented in the two NERA reports.

In particular we believe that additional scenarios should provide an alternative approach on the following assumptions.

- Reduced expansion factors to recognise that most system expansion is achieved by methods that are more economic than new build.
- A reduced expansion constant to recognise that the capital cost of constructing new transmission lines is typically delayed by several years.
- A reasonable allowance for the existence of under-utilised capacity on the existing transmission system.

At section 3 of this response we have suggested additional scenarios that we believe NGC should propose to Ofgem for consideration as part of the Regulatory Impact Assessment.

We welcome NGC's recognition of the need to review the assumptions used in its proposed methodology. However NGC has failed to demonstrate that the assumptions it has proposed for use in its charging model are a reasonable reflection of incremental costs.

¹ National Economic Research Associates

It has therefore failed to show that the extreme locational differences in charges that result from adopting those assumptions are either proportionate or necessary to meet its licence obligations. Having failed to establish the need for such strong locational charges, NGC must submit to Ofgem one or more alternative proposals as described above.

On the basis of the proposals outlined in the August consultation paper, we do not believe the requirement for compliance with EU legislation has been adequately addressed and in particular we believe that the charges that would result from those proposals would be found to be discriminatory and disproportionate.

GB TRANSMISSION CHARGING:

FINAL METHODOLOGIES CONSULTATION

SCOTTISHPOWER UK DIVISION RESPONSE

1 CONTEXT OF THIS RESPONSE

- 1.1 This response should be understood as supplementing the legal, economic and technical arguments advanced in our earlier submissions and in particular our response of 21 May 2004 (the **May Response**) and the NERA report furnished to you on 26 July 2004 (the **NERA Report**).
- 1.2 As we stated in the May Response, and as NGC now accepts, NGC has a duty to ensure that the GB TCM will satisfy the legal requirements of proportionality and non-discrimination and, in order to discharge properly that duty, must take care to evaluate the proposed GB TCM and its potential impact in the context of the available alternatives. We explained in the May Response how, given that the ultimate purpose of the GB TCM should be to ensure economic efficiency and effective competition in electricity generation and transmission, the GB TCM proposed in NGC's April paper (the **April TCM**) failed the relevant legal requirements.
- 1.3 We commissioned the NERA Report in order to examine, in the context of those legal requirements, the objectivity of the April TCM (including the reasonableness of certain core assumptions), the stability of the charges produced by the April TCM, the appropriateness of the pricing signals produced by the April TCM from the perspective of economic efficiency and the possibility of adjustments to the April TCM which might improve its objectivity and the stability and efficiency of its pricing signals.
- 1.4 NERA concluded, in summary, as follows:-
- *Objectivity*: The April TCM and the assumptions underlying it lacked objectivity in that there was no adequate justification offered by NGC for the approach adopted in relation to a number of core parameters in its model. Moreover, in important respects the available evidence indicated that assumptions made by NGC concerning marginal costs were significantly in error. In particular, NGC failed to take proper account of (a) the possibility that capacity can, in light of past experience be expanded more cheaply than by building new lines, (b) the irreversibility of capital investment means that the marginal cost savings from reducing transmission capacity are typically far smaller than the marginal costs of increasing it and (c) the existence of spare capacity in the network.

Thus, the NERA Report confirmed the arguments made in the May Response that the April TCM represented a flawed basis for reflecting actual costs and that it would impose an excessive burden on Scottish generators because the vastly increased charges for Scottish generators had not been adequately justified.

- *Stability*: The April TCM made transmission charges for generators in locations distant from the load centre (peripheral zones) subject to considerable risk of instability, for which there is no objective justification. This instability is as a result of the subjective assumptions used in the April TCM and the much greater sensitivity of charges in peripheral zones to those assumptions. This unnecessary risk would increase investment costs for those generators and would send negative signals concerning long-term investments in generating capacity in those zones.

This confirmed the arguments made in the May Response that the April TCM would produce unjustifiable instability in charges and would impose a discriminatory burden on generators in peripheral zones.

- *Efficiency*: The decision-making by generators which the April TCM would encourage would not be economically efficient, in particular because (a) the unnecessary risk of instability introduced by the April TCM would lead to under-investment, (b) attempts by generators to mitigate the risk would lead to locational decisions which would be inconsistent with those apparently intended by NGC and (c) the failure of the April TCM to provide reasonable estimates of marginal cost is likely to encourage economically inefficient plant closure decisions, particularly in Scotland. If economic efficiency is thus undermined, then so too is effective competition and security of supply.

This confirmed the arguments made in the May Response that the April TCM produced inappropriate locational signals and is unsuitable for its intended purpose of promoting economic efficiency and effective competition.

- *Adjustments*: There are alternative estimates of marginal costs available to NGC which are more objectively justified and would lead to less variation and volatility in transmission charges than those used in the April TCM. In addition, where input parameters for the GB TCM are difficult to estimate it would be good regulatory practice to ensure that outcomes do not vary significantly with subjective changes in those inputs. NGC should implement transitional measures such as giving existing generators certain tradable rights in relation to use of system charges which would reduce unnecessary risk introduced by the April TCM while retaining the benefits of locational signals across Great Britain.

This confirmed the arguments made in the May Response that (a) the April TCM was not necessary to achieve its intended purpose, (b) there are alternatives which better achieve its objectives whilst imposing less burden on individual generators and (c) NGC and Ofgem should give greater thought to the design of the alternatives to the April TCM. In particular, NGC/Ofgem should conduct sensitivity analyses to ensure that the outcome of the GB TCM is not sensitive to input parameters for which there is no adequate justification.

- 1.5 We provided NGC with a copy of the NERA Report, which confirmed that our concerns expressed in the May response were well founded (albeit that NERA in its independent economic assessment had focussed only on issues that were most

easily amenable to further economic consideration). The NERA report has therefore strengthened our views.

- 1.6 We are disappointed to note that despite our concerns expressed in the May Response and supported by the NERA Report, NGC's final proposals are essentially unchanged from the April TCM, other than fixing (for the duration of the price control period) certain features within the methodology in an attempt to provide improved stability and, in Scenario B, further adjusting the G:D split.
- 1.7 NGC now has a clear preference for Scenario B, although Scenario A is included as an alternative that NGC will submit to Ofgem to avoid a situation where Ofgem does not approve its preferred proposal. In that case we believe NGC should include additional scenarios for Ofgem to consider, particularly where NGC has failed to produce adequate justification for the assumptions it has made. We discuss this in more detail in section 3 below.
- 1.8 NGC has suggested a further adjustment to the proportion of the required revenue to be collected from generators and from demand (the G:D split.) NGC acknowledges that negative demand tariffs are an inappropriate outcome of the proposed methodology. The proposed change to the G:D split for scenario B is justified by NGC on the basis that it provides more confidence that negative demand charges will not re-emerge and also because it brings GB more into line with arrangements throughout Europe where typically 100% of use of system revenue is collected from demand charges.
- 1.9 We believe this alteration of the G:D split only serves to mask more fundamental deficiencies in the charging methodology. However, we are supportive of a change to the G:D split in itself, given that this represents a move towards greater harmonisation within the EU. If however such a change is justified on the basis of greater harmonisation within the EU, and it is regarded by NGC as within the scope of this consultation, then it could equally be proposed for Scenario A. Logically NGC should put to Ofgem a further option based on Scenario A with a 10:90 G:D split.
- 1.10 The revised proposals contained in NGC's August paper (the **August TCM**) fail properly to address (and, in certain respects, appear to ignore) the concerns expressed in the May Response and the expert assessment provided in the NERA Report. We therefore fully maintain all of the arguments raised as part of the May Response in respect of the April TCM (and the supporting NERA assessment) in relation to the August TCM. We take that position in light of further expert advice which we have commissioned from NERA in respect of the August TCM, a copy of which is annexed to this paper.
- 1.11 In seeking to criticise NERA's assessment, the August TCM has in fact created further cause for concern in respect of the legality of the proposed GB TCM and the process by which it is being devised.
- 1.12 We highlight, in the following sections of this response, certain aspects of the August paper which either exemplify NGC's failure to address the arguments and assessment already provided by ScottishPower and NERA or raise additional cause for concern.

2 DEFICIENCIES IN NGC'S LATEST ARGUMENTS

Failure to give full consideration to proportionality requirements in a GB context

- 2.1 We are pleased that NGC has confirmed it has a duty to ensure that the GB TCM will satisfy the legal requirements of proportionality and non-discrimination. However, we do not accept NGC's arguments that these requirements have been satisfied by their latest proposals.
- 2.2 Where NGC states that it is the methodology which should be proportionate and not the tariffs, we would point out that Article 23(4) includes "terms and conditions", "methodologies" and "tariffs" in the list of aspects of charging which must be non-discriminatory and proportionate. NGC also maintains that the methodology must be proportionate for England and Wales, given that the Authority has approved it, and as such it must automatically as a consequence also be proportionate for GB. However proportionality relates to the necessity, suitability, burden etc of the methodology for meeting stated objectives, and this can only be considered in the context of the impact of applying that methodology to the network for which it is proposed. Therefore in order to discharge properly that duty, NGC must take care to evaluate the proposed GB TCM and its potential impact in the context of the available alternatives.
- 2.3 Clearly, all of these issues should be assessed afresh over the GB network. This is particularly relevant given that the England and Wales methodology was significantly modified in April 2004 under UoSCM-M-10 and CCM-M-07, and the impact of these modifications² have not yet been appreciated in full even in England and Wales. Therefore in a GB context, it is questionable whether the methodology can still be described as "well known and well understood". It is also important to note that the 2003 Charging Review which culminated in these charging modifications being introduced to England and Wales expressly excluded consideration of GB issues. Consequently, full consideration must be given to the issues arising from the application of the proposed methodology to the entire GB network, before NGC can come to any conclusion on its proportionality in that context.

Assumed equivalence between "proportionality" and "cost-reflectivity"

- 2.4 NGC states at page 63 of its paper, "*We are firmly of the opinion that if the methodology is cost reflective then it is also proportionate and argue that it is the methodology that is proportional and not the tariffs. We also hold the view that the regulations regarding proportionality of tariffs are designed in part to prevent artificial manipulation of charges. Operating a range constraint could be considered as an artificial manipulation. If the tariffs are artificially scaled by a constraining factor then they become less cost reflective and therefore less*

² For example the effect on incremental/decremental cost asymmetry of including deep connection costs in the TNUoS charge, the need for more frequent rezoning due to potentially more volatile nodal tariffs due to the inclusion of generation only spurs, etc. These are discussed below.

proportionate". We maintain that NGC's overriding objective, in the context of devising the GB TCM, is to protect the interests of consumers and that the principal means of achieving this is ensuring that the GB TCM facilitates effective competition and delivers an economically efficient system of electricity transmission. Indeed, NGC has stated, in paragraph 2.3 of the August TCM, "*In the August 2003 consultation, Ofgem/DTI set out their views on the framework that should be adhered to in order to provide a consistent basis for charging that will facilitate competition across GB.*" (emphasis added). Clearly, facilitating competition is a legitimate government objective and the methodology must be suitable and necessary to meet that objective.

- 2.5 In considering how best to pursue this objective, and ensure actual costs are reflected in the charges levied on users, NGC has a duty to act proportionately. In order to do so, NGC must conduct the enquiries and take into account the matters to which we referred in our May Response. It is wholly inadequate to 'short circuit' that exercise by treating cost-reflectivity and proportionality as being synonymous and presuming that this will automatically realise the objective of facilitating competition or make NGC's obligations under Article 23(4) redundant.
- 2.6 Indeed, the approach is clearly at odds with NGC's analysis that the objectives of cost-reflectivity and promoting competition may conflict with one another so that promoting one may only be achieved at the expense of the other. For example, NGC states on page 60 of the August TCM that "*In developing the existing charging methodologies, National Grid has been mindful of its obligations under the Transmission Licence to deliver transmission charges which reflect the costs incurred in the transmission owner activity. In order to satisfy this objective, National Grid will always be required to make a trade-off between stability and precise cost reflectivity of charging.*" Even if NGC were right that it is permissible to trade the promotion of competition against cost-reflectivity (which we do not accept), there would be a proportionate balance to be struck between the two objectives. NGC's view that greater cost-reflectivity must necessarily mean that the TCM is proportionate is thus flawed.
- 2.7 NGC further maintains at page 63 of its paper that, "*[a] further important point to note when considering whether the methodology is proportionate, is that the current England and Wales methodology was approved by the Authority in December 2003 and in their decision letter it was confirmed that the methodology was compliant with European legislation*". In light of the points raised above that the England and Wales methodology needs to be reviewed afresh in the context of the GB market, the fact that it has been approved by Ofgem, cannot properly be treated as an 'important' factor by NGC in considering the effectiveness (in terms of competition and system efficiency) or proportionality of the future GB methodology. This is particularly so when NGC has itself acknowledged that there are significant GB-specific factors that require to be taken into account when devising the latter.
- 2.8 NGC states at page 5 of the August paper "*there is no evidence to suggest that the tariffs associated with Scenario B would not facilitate competition.*" However the evidence presented in the NERA report of 26 July and the supplementary report provided with this response suggests that both Scenario A and B would result in locational differences in charges that cannot be justified. Far from facilitating competition the differential charges proposed by NGC under both scenarios would

provide unjustifiably high payments to some generators, funded by an unjust financial burden on others. NGC has failed to provide evidence or adequate analysis to support the strength of the locational charges that it proposes. An unjustified differential in the charges imposed on generators in different parts of GB will distort competition rather than facilitate it. Without clear and unambiguous evidence to support stronger differential charges NGC would better meet its obligation to facilitate competition by recovering its required revenue from system users through transparent and equitable charges that minimised cost differentials on market participants.

Failure to act transparently

- 2.9 We believe that NGC continues to fail to act transparently, as required by EC law, in devising the GB TCM. We highlight the following points in particular:
1. NGC has shifted its position on the scope of the present consultation exercise since publishing its April consultation paper. In that document, NGC stated that a number of issues, such as the proportionality of the GB TCM were, in the absence of a direction or indication from Ofgem or DTI to the contrary, outside the scope of the consultation. NGC has now chosen to include that and other matters as within its scope but has not acknowledged whether any such direction or indication has been received and, if so, the nature of such direction or indication.
 2. NGC has changed the process envisaged for submission of the GB TCM for approval by deciding to include alternative versions of the methodology in its proposals. However, NGC has failed to explain why it has confined this approach to the single/multi-voltage expansion constant. NGC has not explained why it has not been prepared to submit additional scenarios to Ofgem, particularly where it has failed to provide adequate justification for the assumptions it has used. (See section 3 below.)
 3. NGC claims to have received no direction from Ofgem/DTI in respect of the phasing of charges under the GB TCM. However, NGC does not appear to have sought any such direction, in contrast to the approach taken in relation to whether or not to present more than one option to Ofgem.
- 2.10 These unacknowledged alterations in the scope of the NGC consultation process, together with the opacity of its interaction with Ofgem/DTI on the seeking and receiving of 'guidance', 'directions' and/or 'indications', undermine the transparency of the whole consultation exercise.
- 2.11 NGC has also failed to act transparently in dealing with the question of the expansion constant. The NERA report suggested that more than 80% of transmission system expansion is achieved by means other than constructing new transmission lines. NERA also concluded that these other means of increasing the capacity of the system are typically less expensive than new build and that this should be taken into account by reducing the expansion constant used in the charging methodology. NGC appears to have accepted this argument on page 34 of the August consultation paper where it states that "*The majority of this*

additional capacity has been provided by re-conductoring and re-profiling as these tend to be the most economic method of creating additional capacity, and avoid the issues and risks associated with the construction of brand new transmission circuits.” However, NGC then criticises the way that NERA has interpreted evidence from a US report and then concludes on page 35 of the consultation paper that *“it would not be prudent to develop an alternative expansion constant at this time to deal with the different options for creating additional capacity ...”* NGC offers no evidence whatsoever on the relative cost of system expansion on the NGC network and attempts to justify this decision on the basis that the information is commercially sensitive. It is difficult to accept that such information could not be made available without breaching commercial confidentiality. Having refused to release any cost information to support its position NGC proposes to continue to use the same assumptions about the cost of system expansion, apparently based on unpublished cost information available only to NGC. On page 35 of the August consultation NGC concludes as follows. *“We therefore propose to continue to base the expansion constant on the cost of new build for the GB charging methodology to be implemented from 1 April 2005, using our own sources of cost information.”*

- 2.12 Ofgem/DTI have recognised³ that there is both scope and incentive for NGC, as GB system operator, to discriminate in favour of its own transmission ownership business (e.g. by attempting to set charges that encourage users to connect at points in the network that stimulate the need for investment in its own network assets). Clearly, discrimination of this sort may also prejudice users of one of the non-affiliated networks. In light of this clearly identified risk, we believe that NGC must act, and be seen to act, in a transparent manner to address the concerns highlighted above.

Superficial assessment of uniqueness of the Scottish transmission system

- 2.13 NGC now recognises the need to consider whether there are any unique characteristics of the Scottish transmission system which would affect the extent to which the England and Wales arrangements would achieve the relevant objectives when applied to the GB network. We are disappointed that NGC did not consider these matters earlier in the consultation process. Indeed, NGC dismissed respondents' earlier comments on the suitability of the England and Wales methodology for GB as out of scope of their consultation process, drawing on their interpretation of the December 2003 Ofgem/DTI conclusions as giving them an express direction to use the England and Wales methodologies as the basis for GB.
- 2.14 We believe that NGC's review of network differences presented in this consultation is superficial and relies on flawed arguments to support its conclusions. For instance, NGC argues that there are no issues arising from applying the methodology to the radial circuits and 132kV parts of the Scottish network, nor from the differences in security standards between the Scottish and

³ See, for instance, Ofgem/DTI paper: "Transmission charging and the GB Wholesale Electricity Market Part 1 An Ofgem/DTI consultation on changes to transmission licences to implement GB transmission charging under BETTA" August 2003, paragraph. 5.23; and Ofgem/DTI paper: "Regulatory framework for transmission licensees under BETTA Third consultation on electricity transmission licences under BETTA" December 2003, para. 4.14.

NGC networks⁴. Furthermore, NGC's review fails to recognise that the issue is not only that the Scottish network is different from the England and Wales network, but also that it is as long as the England and Wales network while supporting only 9% and 13% respectively of the GB demand and generation. The GB network will comprise these different networks connected end-to-end and hence will be twice as long but no more wide than the England and Wales network. Lack of homogeneity within a long, thin network is, we believe, a significant issue that NGC has not addressed. This has a profound effect on the charges in Scotland, both in absolute terms and relative to other GB market participants connected in England & Wales.

- 2.15 We believe that NGC's failure to take full account of these issues has magnified the marginal costs applicable to the Scottish nodes as compared to England and Wales nodes. This distorts the locational differentials and results in a vastly increased range of tariffs over the GB network (£31/kW in scenario B) compared to the England and Wales network (£15/kW in 2004/05). NGC has also failed to associate this fundamental difference between the England and Wales and GB networks, with the vastly increased, and we believe disproportionate, range of tariffs when the England and Wales methodology is applied to GB, nor identified it as the underlying cause of negative demand tariffs. We believe that a means should be sought of reducing the range of tariffs over GB in order to restore proportionality.
- 2.16 We believe that the range of tariffs produced by applying the England and Wales methodology to GB are not proportionate, and the proposed TCM is not *suitable* for GB in that it leads to distorted locational differentials between Scotland and England and Wales, and this leads to an *excessive burden* on Scottish generators. Furthermore, this burden is *unnecessary* given that there exist possible modifications to the methodology, which would reduce the range of tariffs while being justifiable with reference to the relevant charging objectives.

Failure to consider relative costs of other methods of system expansion

- 2.17 The above effects are amplified by the use of an expansion constant based on the assumption that all increases in transmission capacity are achieved by the construction of new transmission lines, when cheaper alternatives are available and are used. This, taken together with the additional findings in the supplementary NERA report (appended to this response) demonstrates that the proposed expansion constant lacks objective justification and, thus, undermines the proportionality of the proposed TCM.

Failure to consider asymmetry of incremental and decremental costs

- 2.18 Not only does the TCM assume that all increments of capacity will be met by the construction of new transmission lines, it also assumes that the value of any decrements of required capacity will be the avoided cost of constructing that capacity. We believe that this is an unrealistic assumption, on which the NERA Report commented extensively at paragraphs 4.6.2 and 6.4, and that continued

⁴ A detailed discussion of these issues is provided as an appendix to this response.

reliance on this assumption further undermines the proportionality of the proposed TCM.

Failure to consider the full consequences of the introduction of the Plugs connection charging methodology

- 2.19 One of the consequences of the introduction of the new Plugs connection charging methodology is a change to the treatment of the costs of transmission infrastructure local to the site of a new generator. Previously, these costs would have been treated as connection costs and recovered from the newly connected party either through connection charges or termination charges. Under Plugs these costs are recovered from all system users through TNUoS charges and will remain with those users when the connected party terminates its agreement, thus increasing the charges on those users. This transfer of costs has increased the avoidable costs of closure of a station while, at the same time, reducing the costs of connection of a replacement (as the local costs will be treated as infrastructure). This indirectly sharpens the locational differentials across the network and further undermines the proportionality of the proposed TCM.
- 2.20 Another consequence of the introduction of Plugs and the associated change to the TNUoS charging methodology is the volatility of nodal tariffs due to the inclusion of connections which were previously treated as generator only spurs. This has led to the introduction of more frequent rezoning, with a consequential increase in the uncertainty surrounding future tariffs.

Misrepresentation of impact on Scottish generation

- 2.21 Throughout this consultation NGC refers to the “broadly neutral” effect of the April TCM on Scottish generation, drawing on analysis from the NERA Report. However this assessment can only be justified when £62m of interconnector charges and transfer of £25m of connection charges to infrastructure is taken into account. Describing the proposals as broadly neutral is misleading and does not give a complete picture of the true impact of the move to a locational GB TCM on Scottish generation for the following reasons.
- 2.22 As we have previously indicated, the current interconnector charges, which are targeted only on Scottish generators seeking access to the England and Wales market, represent an unfair and discriminatory burden on those generators. The European Commission has rightly identified this type of charging as a barrier to competition. It is not consistent with the requirements of EC law and, in particular, Council Directive 2003/54 in conjunction with Regulation 1228/2003. We note that NGC recognises, at page 59 of the August consultation paper, the legal requirement to remove 'tariff pancaking', although we question why NGC takes the view that compliance with this requirement can await the joining of the CBT scheme, rather than 1 July 2004.
- 2.23 In addition the level of charges faced by Scottish generators should be considered in the context of the corresponding effect on E&W generation, with which Scottish generators will be competing in the single GB market. In the April TCM both

Scenario A and B led to lower generation tariffs in every zone in England and Wales, despite these tariffs incorporating a share of the costs of the interconnector, which were previously recovered over Scottish users only. In the August TCM the total use of system revenue collected from E&W generators under Scenario A would fall by £28 million from the current year, while under Scenario B the net payment by England and Wales generators would be negative (i.e. there would be more cash paid out to generators in negative charge zones in England and Wales than is collected from generators in positive charge zones in England and Wales). Hence NGC's proposals represent a sizeable transfer of revenue between Scottish and E&W generators. In a competitive market it is more important to consider the impact in relative rather than absolute terms.

- 2.24 The disproportionate nature of charges that would be imposed on Scottish generators can be further demonstrated by considering that under NGC's August proposals the average charge on Longannet Power Station for example would be between £21 million (Scenario A) and £27 million (Scenario B) more per year than an equivalent station based in England and Wales⁵. NGC is required to facilitate effective competition in generation and supply of electricity. It is difficult to see how the extreme differentials comparing Scottish generators' share of transmission charges with that of their competitor generators in England and Wales can be reconciled with this objective.

Use of flawed logic to reject range constraints

- 2.25 NGC argues that since the maximum generation tariff differential of £15/kWh produced by the methodology over England and Wales has been acceptable, the methodology must therefore be proportionate and suitable for GB. We have explained at sections 2.13 to 2.16 why this argument is misguided. It is not logical to say that the methodology must be suitable for one network because it leads to an acceptable range of tariffs when applied to another. Proportionality must be considered in the context of the network to which the methodology is applied. Applying the England and Wales methodology to GB doubles the range of generator charges even though the GB market is less than 15% bigger (measured in terms of total connected generating capacity) than the England and Wales market⁶.
- 2.26 We maintain that the range of tariffs for generators operating within the same market should not be allowed to increase without bound. Locational differentials produced by the proposed methodology over GB are excessively high, being distorted by unjustified assumptions and NGC's failure to consider the full impact of network differences.
- 2.27 Although we would prefer this issue to be addressed within the model, we presented the Range Constraints approach as a mechanism for achieving this cap on the tariff range, in the absence of a natural "check" within NGC's model or modification to reduce the locational differentials. In essence, this approach would test whether the range of tariffs resulting from the model exceeded a given

⁵ Based on the average charge rates in England and Wales under each scenario.

⁶ We also believe that the methodology is unsuitable for England and Wales as stated in our responses to the 2003 England and Wales Charging Review.

threshold, and if so would scale back the expansion constant in order to reduce the range to this threshold value. For avoidance of doubt, the mechanism only serves to impose a maximum tariff range. If the tariff range did not exceed the threshold, then it would remain unaltered by this mechanism. Hence it is not correct for NGC to say that it would lead to a stretching of tariffs when applied in the reverse situation of moving from a single GB market to a separate England and Wales market.

- 2.28 We note that the Range Constraints approach was supported by 4 respondents and are disappointed that NGC has rejected it, relying on flawed logic as to the reverse situation, and the assertion that the threshold we proposed was “arbitrary”. The factor of 5.25 that we had proposed was not arbitrary, rather it was derived from a consideration of the range of generation tariffs in England and Wales. However, we accept that this is not the only way in which an appropriate range threshold could be defined. The key principle of the range constraints approach is to provide some means of testing whether the range of tariffs resulting from the methodology is disproportionate, and of remedying this when it occurs.

3 ALTERNATIVE SCENARIOS

- 3.1 NGC has indicated in the August consultation that it is prepared to submit more than one scenario to Ofgem. The supplementary NERA report appended to this response confirms that NGC has failed to provide a satisfactory justification for many of the assumptions used in both Scenario A and B. Alternative assumptions, which NERA has shown are more consistent with available evidence, would have a significant impact on the charges that GB systems users would be required to pay. In these circumstances we believe NGC must at least submit to Ofgem one or more additional scenarios, which adopt alternative assumptions to those made by NGC to date. In particular we believe that additional scenarios should provide an alternative approach on the following assumptions.

- Reduced expansion factors to recognise that most system expansion is achieved by methods that are more economic than new build.
- A reduced expansion constant to recognise that the capital cost of constructing new transmission lines is typically delayed by several years.
- A reasonable allowance for the existence of under-utilised capacity on the existing transmission system.

- 3.2 By failing to address any of the above issues, NGC’s methodology is deficient in assuming that each flow increment cannot be accommodated unless there is a corresponding increment in transmission capacity, that this capacity increment is always through the construction of new transmission circuits, and this construction takes place immediately. Each of these deficiencies in NGC’s approach leads to exaggerated system expansion costs and magnifies the range of tariffs. Hence they are particularly important to address when extending the England and Wales methodology to GB.

- 3.3 The original NERA report proposed an Alternative TCM which addresses all three of the above assumptions. We are disappointed that this alternative scenario was not included in the final methodologies consultation. NGC’s rationale largely focussed on the complexity of taking these issues into account within the limited

time available for finalising the GB charging proposals. We do not believe that this justifies taking no account of any of the above issues.

- 3.4 We believe that NERA's analysis provides sufficient basis on which to develop a set of alternative scenarios as variations on the August TCM, each of which better meet the relevant objectives by addressing one of the above issues, while retaining NGC's assumptions for the other two. These alternative scenarios should then be presented to Ofgem, either individually or in combination. In developing these alternatives NGC should provide access to underlying data in a more transparent manner than it has so far.
- 3.5 Consider first the current assumption that all incremental capacity is provided by the construction of new transmission circuits. The original NERA report argued that in practice there exist other means of increasing transmission capacity which are frequently used in practice, and which are generally cheaper. NERA concluded that it would be appropriate to scale the expansion constant by a weighted average of the relative costs of other means of system expansion. NERA's supplementary report updates NERA's earlier estimates of the resulting weighted average relative cost, now given as either 69% (Table 2.2) or 76% (Table 2.4) depending on whether capacity additions from load flow controls are included in the calculation.
- 3.6 On this basis we can construct a pair of **alternative scenarios A1 and B1**, which differ from NGC's proposals only to the extent that the expansion constant is scaled by a factor in the range 69-76%, and **better meet the relevant objectives by recognising that most system expansion is achieved by methods that are more economic than new build.**
- 3.7 Consider now the assumption that all incremental capacity is installed immediately. The original NERA report argued that there is normally a long time delay associated with the construction of new lines. NERA therefore concluded that the new build cost should be discounted, and recommended a scale factor of 56% based on a delay of 10 years. We are disappointed that NGC's latest consultation makes no reference to this aspect of NERA's recommendations, and believe that this issue is particularly important to address within a model which is intended to be based on forward-looking costs. Indeed NGC states on page 31 of the August paper "*Scenario A would assume immediately that the new circuit has been upgraded, where in reality, the construction work may not be completed for a further 5-10 years.*" Applying NERA's approach to a delay of 5 years leads to a scale factor of around 75%.
- 3.8 We can then construct a second pair of **alternative scenarios A2 and B2**, which differ from NGC's proposals only to the extent that the expansion constant is scaled by a factor in the range 56-75%, and **better meet the relevant objectives by recognising that new build is typically delayed by 5-10 years.**
- 3.9 Finally, consider the assumption that there is no spare transmission capacity, such that all flow increments can only be accommodated by expanding system capacity. NGC's current England and Wales methodology, on which NGC's proposals are based, has historically modelled spare capacity by scaling the lengths of lines identified as under-utilised. However, none of NGC's GB scenarios make any such

allowance, and NGC has made contradictory statements in its three GB consultations so far as to the need to take account of spare capacity in the model.

- 3.10 In its December 2003 Initial Thoughts paper, NGC said *“It would seem appropriate to continue to apply this approach on a GB basis.”* However, in the April 2004 Initial Methodologies consultation, NGC then said *“Due to the potential interaction with a single GB expansion factor, the concerns regarding GB wide consistency, and taking account of the materiality, it is proposed to remove the modelling of circuits with spare capacity from the initial GB charging methodology.”* Hence NGC’s view at that time was that although it was strictly appropriate to model spare capacity, it was too complex to do so for the GB network.
- 3.11 However, in the latest consultation NGC now presents a new argument that it is unnecessary to model spare capacity as this is already implicitly allowed for in the DCLF model, yet this would appear to contradict their strong assertion that the current England and Wales methodology, which does model spare capacity, meets the relevant objectives.
- 3.12 We would also highlight the following extract from page 11 of NGC’s consultation document on UoSCM-M-10: *“One respondent commented that as the transmission network is well developed, any enhancements to routes should be considered as uprating rather than providing additional circuitry. The respondent felt that this would imply that the expansion constant should be less than for new build, and therefore further adjustments for security would not be cost reflective.”*; to which NGC responded: *“The current charging process does distinguish between circuits that have an excess of capacity via the under-utilised line process. National Grid also believes that the current process for determining additional usage of the transmission system using incremental approach is appropriate as it correctly reflects the marginal costs associated with incremental investment. An incremental approach is used to avoid the instability and volatility associated with ‘lumpy’ investment approach. This has also been the long-standing preference of users in terms of modelling approach, which has been referred to throughout the Charging Review.”*
- 3.13 NGC’s latest argument therefore contradicts its previous statements, and confuses the accounting treatment of the cost of the lines with the economic treatment of the cost of the incremental capacity. It is further criticised in NERA’s supplementary report.
- 3.14 We do not believe that NGC has adequately justified its statement that there is no need to model spare capacity in the GB methodologies. The above UoSCM-M-10 extract shows that NGC clearly accept the need to reflect the existence of spare capacity on the network in a model which does not recognise that system expansion need not be through new build.
- 3.15 We recognise that it is complex to identify under-utilised lines for the modelling of spare capacity for the GB network on the same basis as that previously carried out for E&W. However, this is no reason not to model spare capacity at all. It just means that a simpler approach should be found, and we would highlight that on many other matters NGC, and indeed Ofgem, have taken a stance that a

methodology which addresses an issue in a simple manner better meets the relevant objectives than one which does not address the issue at all.

3.16 Given the strong correlation, as highlighted by NERA, between the lines identified as under-utilised and the lines with flows under a given proportion of their rated capacity, we would suggest that this correlation would be a suitable basis on which to identify under-utilised lines. We also note that NERA recommended that a suitable threshold would be circuits with a flow below 30% of rated capacity.

3.17 We can then construct a third pair of **alternative scenarios A3 and B3**, which differ from NGC’s proposals only to the extent that all circuits with base flows under 30% of rated capacity are identified as under-utilised such that their lengths are scaled by 75%. This would **better meet the relevant objectives by recognising the existence of spare transmission capacity**.

3.18 The features of the above alternative scenarios are summarised in the following table.

Scenario	Description	Assessment against relevant objectives
Scenario A1/B1	<p>Identical to Scenario A/B except: Expansion constant scaled by a factor F</p> <p>Value of F based on weighted average relative cost of different methods of system expansion</p> <p>NERA analysis suggests F should be in the range 69-76%</p> <p>Suggested range based on NERA analysis of different methods of system expansion</p>	<p>Better meets relevant objectives than A/B by recognising that most system expansion is achieved by methods that are more economic than new build</p>
Scenario A2/B2	<p>Identical to Scenario A/B except: Expansion constant scaled by a factor G</p> <p>Value of G based on discounted costs of delayed new build</p> <p>NERA analysis suggests G should be in the range 56-75%</p> <p>Suggested range based on a delay of 5-10 years</p>	<p>Better meets relevant objectives than A/B by recognising that new build is typically delayed by 5-10 years</p>
Scenario A3/B3	<p>Identical to Scenario A/B except: All lines with base flow under X% of rated capacity identified as under-utilised</p> <p>Lengths of under-utilised lines are scaled by 75%</p> <p>NERA analysis suggests X should be 30</p>	<p>Better meets relevant objectives than A/B by recognising the existence of spare transmission capacity</p>

4 DETAILED COMMENTS ON AUGUST TCM

- 4.1 We believe that the August TCM is not a significant departure from the April TCM, and still fails to satisfy the critical requirements of proportionality, such that the arguments presented in our May response and supported by the NERA report generally still apply. However, we also have some specific comments on the details of the August TCM. These detailed comments should not be taken to imply any acceptance of the underlying methodology nor of either of the two scenarios.

Use of Interim SYS data

- 4.2 Should the DCLF model be used for calculating GB TNUoS tariffs, then we agree that the 2005/06 tariffs should be based on data from the Interim GB SYS, which is expected to be published in October 2004. We would ask that NGC reissues the DCLF model incorporating the Interim GB SYS data as soon as possible after it is available, together with updated illustrative GB TNUoS tariffs calculated using that data. This will not only improve transparency and update users as to the likely tariffs to which they would be exposed, it may also help inform their responses to the forthcoming Ofgem Impact Assessment on NGC's final recommendations.

TEC scaling

- 4.3 We are disappointed that NGC has misinterpreted our comments regarding TEC scaling, and now proposes not to pre-scale any generation prior to use in the DCLF model. NGC's stated rationale is that the TEC value is chosen and submitted by the generator and "*every plant type has the right to export up to this value at any time*". NGC therefore concludes that all generation types should be treated on the same commercial basis for modelling and for charging. However, NGC does not state here that the further reason for the current approach is the assumption that every plant will aim to export at full load at system peak, in response to higher market prices. The DCLF model therefore uniformly scales all TEC such that the total generation in the load flow matches peak demand. We agree that this is generally a reasonable assumption, such that it is not appropriate to use, for example, a merit order approach. However, we do not believe it is a suitable assumption for generators with uncontrollable limitations on their energy source. For example there is only about a 35% probability that a wind-powered generator will be capable of generating at the time of system peak.
- 4.4 We note that this is a new issue for BETTA, given that there are currently no transmission-connected or CVA-registered windfarms in England & Wales, hence none which are liable for generation TNUoS charges on the basis of TEC. We restate our view that the TEC value for windfarms should be scaled down prior to inclusion in the DCLF model, to reflect the fact that it is unable to choose to run at full output in response to market signals. We also remain of the view that a scale factor of 43% is appropriate, as is used in the Declared Net Capacity definition used for determining eligibility for exemption from a generation licence.

Furthermore, we see no sound basis for NGC's argument that no scaling should take place on licensable generation merely because it is licensable.

- 4.5 We would also point out that with the expected growth of transmission-connected wind generation in the short to medium term, particularly over Scotland, it becomes increasingly absurd to assume that all such intermittent generation will be generating at full capacity at system peak. Indeed to do so would further overestimate the nodal marginal costs over the Scottish nodes in the DCLF model, exacerbating our proportionality concerns above.

Embedded generation

- 4.6 We note that NGC has now made available data on embedded generation in Scotland by issuing the gross values of generation and demand for all Scottish nodes used in the DCLF model issued with the Initial Methodologies Consultation. We would ask that NGC complete this action by providing the same level of transparency for embedded generation in England & Wales explicitly modelled as negative demand and directly charged as negative demand. We would also point out that the August TCM treats embedded generation in Scotland differently from embedded generation in England and Wales. The submission of demand data by the DNOs in England and Wales is net of the expected output of the embedded generation at time of system peak. The August TCM, however, assumes that Scottish embedded generation will be operating at its registered capacity. This will potentially overstate the effect of this generation in the transport tariff calculation.

Expansion constant and expansion factors

- 4.7 We agree that the expansion factors should be fixed within the price control period, and the expansion constant should be set at the start of each price control period and subsequently adjusted for inflation. However, the fixing of these parameters makes it even more important to establish correct values in the first place. As discussed elsewhere in this response we believe that the current methodology for deriving the expansion constant significantly over-estimates the costs of expansion since it assumes all incremental flows lead to a requirement for incremental capacity and that this can only be provided by the immediate construction of new lines.
- 4.8 We would also suggest it would be more appropriate to adjust the expansion constant by RPI-X, as per NGC's transmission price control, rather than simply RPI. Further, we note that NGC propose to use a weighted average expansion factor for 132kV lines (being a ratio 20:80 of the costs for 400kV:132kV), and see no reason why a similar principle should not be applied to the expansion factors for 275kV.
- 4.9 We agree that the expansion factors for cables should be reduced in order to ensure they receive a fair allocation of transmission running costs.

Generation zones

- 4.10 Although NGC has undertaken a thorough re-zoning exercise for this consultation, it proposes that the final generation zones for 2005/06 will only be “*confirmed as part of the standard charge-setting process*”, i.e. not notified to users until the end of January 2005. NGC also proposes that zones will generally be fixed within price controls, but the methodology will allow rezoning in some circumstances. However, NGC has not provided any illustrative drafting of the proposed provisions in this regard for the GB methodology statements. We note that NGC recognises that the definition of zones can affect the extent to which the tariffs are cost-reflective and facilitate competition. In the absence of more detail on the provisions for rezoning, it is unsatisfactory to perpetuate the current arrangement introduced via UoSCM-M-10 whereby zones may change each year and are not notified to users until the last minute. Provisions should be introduced into either the methodology statement or the transmission licence, which require NGC to give a minimum notice period of its intention to change the zones for any given year, and a minimum notice period for the finalised zones. These timescales should be aligned with those for making modifications to the methodologies.

Hydro-benefit, renewables assistance and small generators discount

- 4.11 We believe that each of these mechanisms should operate outside the main TNUoS charging methodology, but that this does not remove the need for transparency. We believe that the methodology by which the associated tariff adjustments are calculated and applied should be published by NGC, with the charging methodology statement produced under Standard Condition C5. Also, the associated charges and tariff adjustments should be included in the statement of charges produced under Standard Condition C4, but detailed separately from the main TNUoS tariffs. To further aid transparency there should be full separation of all the data users that need to be able to replicate both the derivation of the basic TNUoS tariffs, and the calculation and application of any supplements and adjustments to those tariffs. Any under/over-recovery of these charges should be carried forward through separate revenue adjustments applicable only to the appropriate charge base.

STTEC charge

- 4.12 Our responses to UoSCM-M-13 and CAP070 stated our strong opposition to the proposed charge for STTEC, on the basis that it is clearly not cost-reflective and risks setting an inappropriate precedent that charges for different access products should necessarily be derived from the current charge for TEC, rather than being suited to the product and satisfying the relevant charging objectives in that context. Both these concerns are exacerbated when UoSCM-M-13 is considered in the context of GB charging, in which locational TNUoS charges for TEC would be considerably higher in Scotland compared to England & Wales under NGC’s proposed methodology. We would also point out that NGC clearly recognises that its STTEC charge is not cost-reflective, yet still believes it meets the relevant objectives. This position on the importance of cost-reflectivity is in direct contradiction to their approach to charges for TEC.

- 4.13 The STTEC charging proposals were clearly developed in a rush for implementation in England & Wales in time for winter 2004/05. Whether or not UoSCM-M-13 is extended to GB, we believe strongly that the issue should be reconsidered in a GB context after BETTA and a charge developed which reflects the costs of provision of short term transmission capacity, without being constrained to be based on the charge for TEC.

Application fees

- 4.14 We note that NGC proposes to review application fees such that they reflect the number of transmission licensees involved in assessing the application. This could clearly lead to higher fees for Scottish applicants, due to the unavoidable need to involve more than one transmission licensee as a result of the regulatory framework chosen by Ofgem/DTI for BETTA. The higher costs associated with applications for connections to the Scottish networks is in no way the fault of Scottish applicants, rather it is driven by the BETTA design. It is therefore inappropriate, and indeed discriminatory, to target such costs on the basis of the number of transmission licensees involved in processing the application. Fixed fees should be applied irrespective of location.

Ownership/connection boundary in connection charging methodology

- 4.15 The variety of generator connection arrangements in Scotland has highlighted the absence from NGC's connection charging methodology of a means of determining when a circuit connecting a remote generator to the main system should be treated as infrastructure rather than connection. To address this problem NGC has proposed an arbitrary distance rule of 2km, based on an implicit rule which has, apparently, been used in the past for demand connections. We do not support this approach. We believe that there may be circumstances where a shorter connection is clearly shareable, and should be treated as infrastructure. It is also conceivable that, in other circumstances, a longer connection might not be shareable. A blanket rule based on an arbitrary distance is not satisfactory. We believe that this issue requires further consideration of the factors that may or may not make a connection shareable before a final proposal can be made. Meanwhile, the connection boundary at each site potentially affected by the proposed rule should be considered on a case by case basis and agreed with the affected user.

5 PROCESS AND TIMETABLE

- 5.1 We note that NGC proposes to submit draft Statements of Charging Methodology to the Authority with its Final Proposals report. We would highlight that it is important that users be given the opportunity to comment not just on the proposed charging principles, but also on the translation of those principles into binding legal drafting. We look forward to the proposed methodology statements being issued for industry consultation before the methodologies are finalised.

- 5.2 NGC should reissue the DCLF model and recalculated tariffs based on the Interim GB SYS data once available, and give more notice of the final generation zones proposed for 2005/06.

APPENDIX –

A1 GB Security Factor

NGC has maintained its position (section 4.2.5) that a single GB security factor should be used in the calculation of the nodal marginal costs and that any difference in the security standards between the three constituent transmission networks is not relevant. We do not accept this position on two counts. Firstly the effect of differences in the historic standards on the design of the network, and secondly the effect on the calculation of the Locational Security Factor.

Historic design of the networks

There are two differences between the security standards used by the Scottish licensees and those used by NGC which affect the amount of transmission capacity which has been provided. The first of these is the *interconnection allowance*. For any given division of the NGC system into two sub-systems, the boundary transfer which results from the scaling or ranking of generators to meet the ACS demand is increased by an allowance which is related to the demand and generation in the smaller sub-system relative to that of the total system. The assessment of system performance against the specified secured events will therefore take place against a higher level of boundary transfer than would be the case if the interconnection allowance had not been applied. This is likely to result in more capacity being provided. If this additional capacity requirement has led to more interconnection within the network then the TNUoS tariff differentials across the network will have been reduced. Historically, interconnection allowance has not been applied in Scotland.

The second difference relates to the *secured events* on each network. While both NGC and SPT/SHETL secure the supergrid network against a double circuit overhead line outage under prevailing system conditions, i.e., with maintenance outages in progress, SPT only does this under adverse weather conditions. This can be achieved by managing outages such that they can be avoided or restored during adverse weather periods. This is difficult to achieve on the heavily loaded NGC network, hence it might be expected that NGC will have met this condition by providing more circuits.

Overall therefore, the NGC design standards should deliver a higher capacity and more interconnected network than the Scottish standards. This is confirmed by findings of the expert group which has been reviewing the standards for BETTA. In the recent consultation on Planning and Operating Standards under BETTA⁷, Ofgem/DTI report that, in respect of the main interconnected transmission system, the group “identified that neither of the existing standards could be applied across GB without triggering additional transmission system investment requirements or reducing the minimum level of security on the transmission system.” Such a difference in network provision will affect the calculation of the GB TNUoS tariff differentials. Generally speaking, higher levels of interconnection appear to reduce tariff differentials. Thus the basic tariff calculation might be expected to produce lower differentials in England and Wales than in Scotland for the same geographic distance between two nodes. This effect is then magnified by the operation of the secured loadflow model which drives the locational security factor.

⁷ Planning and operating standards under BETTA, An Ofgem/DTI consultation document, Volume 1, July 2004, paragraph 5.39

Calculation of the Locational Security Factor

The secured loadflow applies specified contingencies to the basic loadflow model to determine the maximum incremental MWkm for the post-fault loadflows. There are two aspects to this which will magnify the tariff differentials faced by Scottish system users.

Firstly, as noted above, the design standards may have shaped the NGC system to have a higher level of interconnection, and hence lower tariff differentials than the Scottish networks. The level of interconnection will also influence the post-fault incremental MWkm, thus the consequences of the historic difference in standards is compounded by the methodology used to allocate the cost of security on a locational basis.

Secondly, the specified contingencies relate to the operational security standards which require the SPT supergrid network to be operated to withstand a double circuit overhead line fault on prevailing system conditions under adverse weather conditions, and to withstand a single circuit fault in the absence of adverse weather conditions. As noted above, SPT generally meets this requirement by managing outages to retain an intact network during the relatively small proportion of the year when adverse weather conditions occur. SPT would also aim to have an intact network, as designed, at the time of system peak. At other times, the network is only partially secured against a double circuit overhead line fault and, arguably, the user is receiving a lower standard of service during these periods. In determining the tariffs, however, NGC study a version of system peak conditions and claim equivalence with England and Wales because the more onerous standard would be in operation in Scotland. While this may be the case at that time, this approach overstates the requirement for additional capacity to provide security because it applies a standard which will not be applied for most of the year and thus charges for a higher level of security than that which the user receives over the course of the year.

The incremental cost derived from the secured loadflow is used to derive the locational security factor which is then applied to the nodal marginal cost derived from the basic loadflow. Thus the basic tariff differentials, already higher in Scotland than in England and Wales as a consequence of differences in the design standards, are increased by a factor which is higher than is appropriate in Scotland due to differences in both the design and operational standards. Given that the existing security standards are to be continued as regional variations to the overall GB SQSS, both the basic incremental MWkm and the locational security factor should be reduced for Scottish nodes in order that the lower level of network investment implicit in the SQSS is reflected properly in the TNUoS tariffs. Otherwise, the charging methodology will implicitly reward users of the more generously specified network and penalise users of the more economically specified one.

A2 132kV network issues

NGC state that: *“The existing England and Wales methodology is applied across the two transmission voltages of 275kV and 400kV. It is also applied to those 132kV circuits which are owned by National Grid. If the England and Wales methodology is applicable to 132kV circuits in England and Wales, then there appears to be no reason why it can not also be applied to 132kV circuits on a GB basis. Furthermore, as the England and Wales methodology is applicable to more than one transmission voltage, we see no reason why it cannot be applicable to a third transmission voltage. Indeed, in terms of transmission capacity, the ratio of 400kV to 275kV is broadly comparable to the ratio of 275kV to 132kV. We therefore do not believe that the existence of 132kV transmission prevents the England and Wales charging principles from being used as the basis of a GB charging methodology.”*

There are two problems with this line of argument. Firstly, it considers the issue primarily in terms of whether the charging methodology and associated DCLF model can accommodate modelling a third transmission voltage. However, this is clearly the case given that NGC developed the model on the basis of it having multi-voltage expansion factors, including 132kV, hence it is a spurious argument. Secondly, it does not deal with the more fundamental question of whether there are any implications of the designation of 132kV as transmission in Scotland only, which affect the suitability of the England and Wales methodology when applied to GB. Although NGC point out that the current methodology is applied to NGC’s 132kV circuits in England and Wales, this is not a sufficient basis on which to conclude that it is suitable for application to the extensive Scottish 132kV network. On examination of the latest GB DCLF model, we note that the only 132kV circuits in England and Wales are spur circuits connecting Oldbury 132kV substation to Iron Acton 132kV, which in turn is connected to the supergrid via transformers to Iron Acton 275kV. Hence the modelling of these England and Wales 132kV circuits only affects the nodal marginal costs at OLDS10, therefore has negligible effect on the results over the rest of the network. However, with 132kV as a transmission voltage in Scotland, there are large interconnected parts of the network at that voltage. The manner in which 132kV circuits are treated in the model can therefore have a significant effect on the nodal marginal costs over that whole region. Given that NGC’s Scenario B applies a higher expansion factor to 132kV than other voltages, this leads to higher marginal costs for Scottish nodes at 275kV and 400kV as well as those at 132kV. Also there are different (i.e. lower) security standards at 132kV compared to higher voltages, and this needs to be taken into account in a methodology which incorporates a locational security factor in order to avoid overstating the nodal tariffs by applying a factor based on higher standards.

We would also point out that the Scottish radial network is not analogous to generation only spurs (GOS). The former connects large parts of the network while the latter is just for isolated stations. While the GOS might have been a commercially informed choice of the generator, knowing that the costs of the spur would be targeted on them, that is not the case for the multiple users connected to branches of the Scottish radial network.