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Response to NGC December 2004 Consultation on GB Transmission Charging

Scottish Power

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Executive Summary

On 20 December 2004, NGC published a further consultation document on GB Transmission Charging and its proposed use of system charging methodology, in response to the decision document issued by the Gas and Electricity Markets Authority ("the Authority") on 10 December 2004. NGC's consultation document followed on from four previous consultative documents and reports published in December 2003, April 2004, August 2004, and September 2004. We submitted reports commenting on the second and third of NGC's publications, those in July and September 2004. NGC's report addresses many of the concerns raised by the Authority's latest decision document, and in our two previous commentaries. This report provides NERA's commentary on the latest NGC publication.

In the latest publication, NGC offers more explanation of its methods, but we still found a number of faults or inconsistencies in NGC's methodology. NGC has purported to address most of our earlier points, but the evidence is in places inconsistent or misleading, and the economic rationale provided for its methodology is often confused or at odds with NGC's stated objectives. In many areas, NGC has not provided sufficient underlying data to allow proper external scrutiny of the assumptions and calculations behind the Transmission Charging Methodology. Overall, where NGC does provide data or explanations, we find that the new evidence has in most cases strengthened rather than weakenedNERA's previous criticisms.

Our criticisms focus on four key areas:

- The calculation of the expansion constant (the assumed incremental cost of expanding the capacity of 400 kV lines);
- NGC's comparison of project costs with the differential between tariffs at different nodes;
- The calculation of the expansion factors (the assumed incremental cost of expanding the capacity of 132kV and 275kV lines);
- The treatment of spare capacity and the security factor.

In NERA's earlier reports we identified several methods for increasing capacity, including "reprofiling", "uprating", "re-conductoring" via "bundling" or "restringing", and "load flow controls". NGC has addressed in its report the cost of reprofiling, uprating and reconductoring (although in the latter case NGC does not distinguish between bundling and restringing as we did). However, we believe NGC's methodology still overstates the costs of these alternative methodologies, particularly in the case of uprating voltages and reconductoring. NGC has still not taken into account the lower cost of load flow controls.

At the request of the Authority, NGC carried out a comparison of the tariffs with the actual unit costs of expansion projects. NGC's calculation of unit costs counts the total cost of the project, but ignores some of the capacity created by the project, if that capacity cannot be used immediately due to constraints within other parts of the network. This omission raises the apparent unit cost of adding capacity. The tariff model however, estimates the costs of providing just the capacity needed to accommodate an incremental flow through the system, without any capacity remaining unused.. NGC's comparison of these two figures is therefore biased, and overstates the actual costs of network reinforcements.

NGC does not provide persuasive evidence or reasoning to support its claim that alternative methods for adding capacity at 132kV and 275kV cost as much as new build, which leads to an overstatement of expansion factors and to an unjustified widening of tariff differentials between zones.

We have pointed out in our previous reports that the treatment of spare capacity has a significant impact on tariffs. However NGC's proposed calculation takes no account of spare capacity when assigning a marginal cost to incremental power flows and therefore overestimates marginal costs. NGC's reason for omitting this adjustment now relates to generator-only spurs, but this argument provides no justification for failing to recognise spare capacity on other parts of the network.

NGC provides an example to illustrate its contention that the methodology implicitly takes spare capacity into account. However, the example confuses the concepts of "marginal cost" and "replacement cost" (referring to both at different times as "incremental cost" or "marginal cost") and the example merely confirms that the methodology ***does not*** take spare capacity into account. This omission is not consistent with the stated principles of NGC's pricing methodology.

The effect of ignoring spare capacity is compounded by NGC's addition of a locational security factor. NGC's model takes no account of the fact that if the maximum line flow recorded in the model does not exceed existing capacity then the line flow would not impose any marginal cost for additional capacity. As a result the locational security factor is higher than it would otherwise be.

Thus, NGC has reviewed the costs of adding capacity by other means than new build, but has concluded that they do not substantially lower the cost of adding capacity. Closer examination of NGC's arguments shows that NGC still has not taken some low cost techniques into account (e.g. load flow controls), appears to have overstated the cost of other techniques and still fails to review the key information needed to evaluate properly its estimates and assumptions. Furthermore, NGC's explanation of the argument for ignoring the existence of spare capacity displays a misunderstanding of economic concepts. Taken together, these observations still imply that NGC is overstating the cost of creating new capacity.

Overall, the effect of the errors in NGC's methodology is to widen tariff differentials within Great Britain beyond those which reflect the evidence on marginal costs of investment. We estimate that the effect of the December transmission charging methodology is to make generators situated in Scotland about £82 million per year worse off relative to generators situation in England and Wales. This outcome is inconsistent with NGC's legal duties and stated objectives for its transmission charging methodology, and is likely to promote inefficient decisions by network users and, hence, inefficient investment in the transmission system.

1. Introduction

This report sets out NERA's response to NGC's consultation document, "GB Transmission Charging: Use of System Charging Methodology Revised Proposals Consultation", dated 20 December 2004. Our comments are made in the light of NERA's previous reports during this consultation process:

- "Review of GB-Wide Transmission Pricing", 26 July 2004, which commented on NGC's consultation document dated 8 April 2004
- "Response to NGC's Final Consultation on GB Transmission Pricing", 13 September 2004, which commented on NGC's consultation document dated 20 August 2004

NGC has purported to address many of our earlier points, but still fails to comment on a number of important issues that we raised. Moreover, where NGC does confront NERA's criticisms, its responses in reality inadequate. Indeed, where NGC has provided more evidence to support its estimates, the evidence has tended to confirm our earlier views. In some cases, NGC has expanded upon its economic rationale, but the explanations confuse various economic concepts. Where possible, we have explained the source of the confusion in NGC's December document and have also tried to provide a thorough analysis of the data and the underlying economics.

The report is structured as follows:

- In section 2 we review NGC's calculation of the expansion constant;
- In section 3 we review NGC's comparison of project unit costs to the per unit tariff;
- In section 4 we analyse NGC's calculation of the expansion factors;
- In section 5 we discuss the treatment of spare capacity and the security factor;
- In section 6 we identify the impact of NGC's transmission charging proposals on Scottish generators;
- In section 7 we identify some remaining gaps in NGC's response, i.e. items we have raised previously that NGC has still not addressed;
- In section 8 we present conclusions.

2. The Expansion Constant (s. 5.3.1)

In our reports of 26 July and 13 September 2004, we identified several alternative methods of providing capacity, apart from new build, specifically: "uprating" the voltage of a line from 275kV to 400kV; "re-conductoring" a line by "bundling" or "restringing"; and "load flow controls" that maximise the capacity available from existing circuits. NGC has not responded fully to these suggestions and the analysis in NGC's own report is highly selective, as explained below.

2.1. Reprofiling

NGC accepts that the cost of this method is very low, but gives it a low weighting (only 20% of total potential capacity increments), without any clear justification. NGC reports that only 50% of potential reprofiling projects prove to be feasible, but does not explain the extent of these potential reprofiling projects, or relate it to the 20% weighting.

NGC ascribes to reprofiling a cost of 20% of the cost of new build. NGC also says that there are other projects, involving some additional work and "significantly higher" cost (page 12), However, a project with a cost "significantly higher" that 20% of the cost of new build could still be cheaper than new build, but in its estimate of the expansion constant (page 14) NGC does not appear to make any allowance for such projects, either in the proportion of the expansions attributable to re-profiling, or in the cost attributed to such methods of expanding capacity.

2.2. Re-conductoring

NGC reviews "re-conductoring" and assigns it a high cost relative to new build, but does not distinguish between "bundling" (which is in our view – as we stated in earlier reports - cheaper than new build, on the basis of international evidence) and "restringing" (which we agreed was likely to be more expensive). NGC concludes that the *average* cost of re-conductoring is 140% of the cost of new build. This estimate significantly raises the expansion coefficient calculated on page 14. However, a prudent operator will not choose to use a more expensive method than new build unless there are exceptional reasons for doing so. NGC does not explain why its model should assume that a prudent operator would use methods that were more expensive than new build and other methods in 30% to 50%[1] of all cases.

Moreover, the method that NGC uses elsewhere in its report to measure incremental capacity ignores capacity created but not available due to further constraints in other parts of the system. As we discuss in section 3 below, this omission leads to an upward bias in the measurement of costs. NGC does not discuss the methodology it has used to measure the capacity added by re-conductoring projects, when calculating their cost per unit of capacity. However, if NGC made the same error in measuring incremental capacity in its calculation of re-conductoring costs, then the same upward bias would apply in that calculation and NGC would have over-stated the actual costs of this method.

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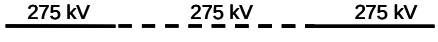
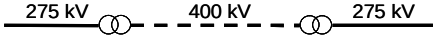
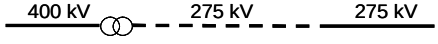
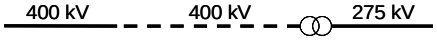
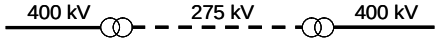
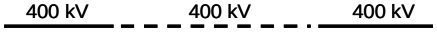
[1] NGC (Dec 2004) *GB Transmission Charging: Use of System Charging Methodology, Revised Proposals Consultation,* 20 December 2004, p. 14, Table 1.

2.3. Voltage Uprating

In relation to 275kV lines, NGC states that projects to uprate the voltage to 400kV incur as "a minimum" the cost of fitting two transformers to change the voltage between 275kV and 400kV (page 13). NGC might incur such costs for uprating a circuit in the middle of a 275kV network. However, it must be more likely that NGC would choose to upgrade a 275 kV circuit that was already linked to a 400 kV network, in which case the costs would be lower, as explained below.

Example (1) in Figure 2.1 shows diagrammatically the case that NGC may have had in mind. (In this figure, we adopt the normal convention of marking transformers as a double circle.) Here, uprating the voltage on part of a 275kV network to 400kV (in the part shown as a dashed line) would require two new transformers. However, in examples (2) and (3) such expenditures would not be required. In example (2) the dashed 275kV line to be uprated is already connected to a 400kV network at one end; in this case, it would be sufficient to *move* the transformer from its current location to the new 275kV/400kV boundary. In example (3), uprating a whole 275kV sub-network to 400kV would eliminate the need for the current 275kV/400kV transformers, thereby *saving* costs.

Figure 2.1
Possible Project Examples - Uprating Voltage

	Before	After
(1) Uprate middle of 275kV network - install two transformers		
(2) Extend 400kV network - move transformer		
(3) Uprate 275kV section of 400kV network - remove two transformers		

NGC attributes a cost of £3 million to the two transformer example, and credits it with creating 900 MW of capacity over 30km. These figures imply an average incremental cost per unit of £111/MW-km or an annuitised unit cost of about £7/MW-km, somewhat lower than NGC's estimate of £9.80/MW-km for 400 kV.[2]

The examples above show that the actual costs may be lower than NGC's own estimate and that they would be lower still if applied selectively to the longest circuits, or to groups of circuits. The examples in the second and third of the diagrams in Figure 2.1 seem to be logically more probable than the NGC example shown in the first diagram, although NGC is likely to be able provide data on the types of projects undertaken in practice.

[2] NGC (Dec 2004), p. 31.

NGC addresses the cost of uprating voltages in its discussion on the derivation of the 400kV expansion constant in section 5.3. However, in principle, NGC should compare the cost of uprating voltages with the cost of building new 275kV lines, which NGC discusses in section 5.4. The cost per unit (MW-km) of building new 275kV lines is greater than the cost per unit of building new 400kV lines due to economies of scale. Uprating the voltage therefore appears even cheaper when compared with the cost of building new 275kV lines, than when compared with the cost of building new 400kV lines.

In Table 5, on page 20, NGC accepts that a high percentage of capacity expansions on 275kV lines could be achieved by uprating voltages: 77% for SHETL, 90% for SPT and 83% for NGC. However, when calculating expansion factors for 275kV lines, NGC only uses the relative costs of building new 275kV and 400kV lines to derive expansion factors for 275 kV lines of 1.07-1.17.[3] Our analysis suggests that uprating voltage from 275kV to 400kV is a cheaper way of adding capacity than replacing 275kV lines with new 400 kV lines. Given that finding, NGC has over-estimated the 275kV expansion factors and, hence, certain tariff differentials.

2.4. Load Flow Controls

In previous reports, NGC has criticised NERA for including load flow controls (reactive power control, quad boosters, etc) within this analysis. NGC originally stated, "Load flow control devices such as Synchronous Voltage Compensation and Quad Boosters do not alter the length or rating of existing circuitry, and we therefore do not believe these measures should be considered as a cause for the increase in capacity since 1992."[4] However, NGC appears to have had a change of heart. Table 2 in NGC's latest document includes a project that creates 1000 MW of capacity at the B7 ("North-Midlands") interface, and which is described as "predominantly reactive compensation" (i.e. load flow control). This statement appears to confirm our view that investment in new load flow controls can release capacity on the system. The project creating 750 MW at boundary B5 also seems to involve some new investment in voltage compensation ("MSCs" and a "series reactor").

NGC's Table 2 gives the project for constraint B7 a cost of £3.4/kW-yr, 87% of the corresponding tariff differential (£3.9/kW-yr), but this cost figure would be an over-estimate if it failed to take into account the full amount of capacity created by the project (see section 3 below).[5] In our earlier reports, we estimated the cost of load flow controls to be only 54% of the cost of new build for 400kV lines. On that basis, even giving load flow controls a relatively low weighting (e.g. 20-25%) would reduce the expansion constant (and hence all tariff differentials between zones) by around 10%.

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[3] NGC's tables (NGC (Dec 2004)) seem to contain a typographical error on page 32. In the table for the Scottish Power region, we believe that the 400kV line factor should be 1.00, as elsewhere, not 1.07, and that the 275kV line factor should be 1.07, not 1.68.

[4] NGC (Aug 2004), *GB Transmission Charging: Final Methodologies Consultation*, 20 August 2004, p33.

[5] Project B5 also seems to involve some reactive compensation and reactance, i.e. load flow controls, but may involve other equipment as well. NGC says it seems to be required to solve "local" problems, i.e. to provide capacity over a short distance. As a result, it is difficult to estimate the start- and end-points of the capacity and hence the appropriate tariff differential for comparison purposes.

2.5. Conclusion

NGC has reviewed the costs of adding capacity by other means than new build, but has concluded that they do not substantially lower the cost of adding capacity. Closer examination of NGC's arguments shows that NGC still has not taken some low cost techniques into account (e.g. load flow controls) and appears to have overstated the cost of other techniques. Taken together, these observations confirm that NGC is overstating the cost of creating new capacity and therefore the differential in tariffs between different zones in Great Britain.

3. Comparisons with Real Costs (s. 5.3)

NGC's discussion of the unit costs of real projects, as summarised in Table 2 on page 17, is compromised by a problem that NGC itself recognises. In calculating the amount of capacity created by an investment, NGC has not examined each circuit in isolation, but has allowed for the effect of constraints in other parts of the transmission system. As a result, NGC is comparing apples and pears by linking increment in costs to the increment in capacity *constrained by other points of congestion* (page 16).

- The tariff model estimates the cost of building only the capacity required to accommodate incremental flows. It does not therefore attribute to any route the cost of building capacity that cannot be used because of constraints at other points.
- In contrast, NGC's analysis of actual projects ignores capacity created by the project, but which could only be made available if NGC carried out another investment project within the grid.

This approach leads to an upward bias in the cost estimates for real projects, compared with the tariff model.

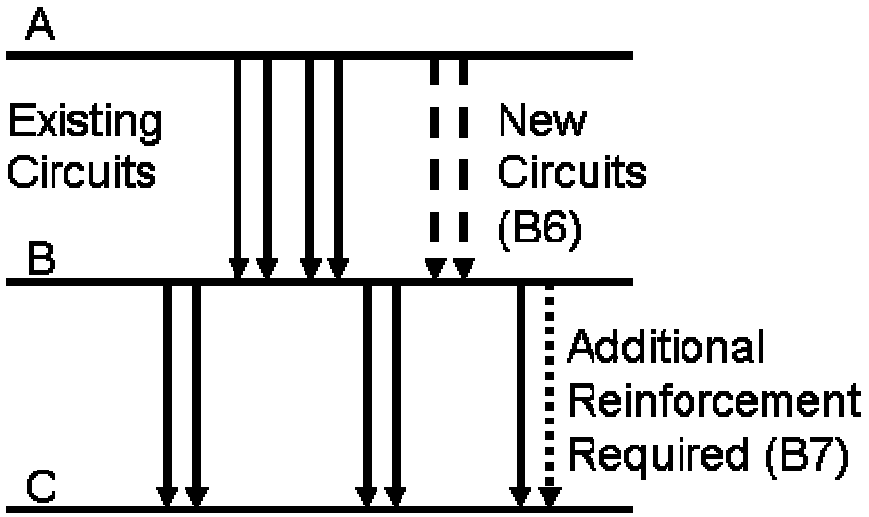
3.1. The Source of the Bias

Figure 3.1 shows schematically a part of the grid similar to that affected by the project to upgrade interconnector capacity at the B6 interface between Scotland and England. Horizontal lines A, B and C represent different parts of the transmission network, A being in Scotland, whilst B and C are in England. Vertical lines represent transmission circuits connecting these parts of the transmission network, each with a capacity of 500 MW. (Neither the vertical lines nor the capacities are intended to provide an actual representation of the network.) There are four existing circuits between A and B (representing about 2000 MW of Scotland-England interconnector capacity) and five existing circuits between B and C (i.e. sufficient to carry the 2000 MW delivered from Scotland, with 500 MW spare).

A project like the one at interface B6 is represented by the addition of two new circuits from A to B, which would provide 1000 MW of new interconnector capacity, bringing the total to 3000 MW. The capacity from B to C is limited to five circuits, or 2500 MW, so (in this simple example) NGC limits the capacity created by this project to an additional 500 MW.[6] As a result, this project appears to have a relatively high cost per unit of capacity made available. However, a small amount of additional investment between B and C would free up the remaining capacity at relatively low cost, and would reduce the total cost per kW (and the annuitised cost per kW-yr).

[6] Table 2 (NGC (Dec 2004)) states that the project increases interconnector capacity from 2200 MW to 2800 MW, i.e. by 600 MW. The example here uses round numbers for simplicity of exposition. In addition, our example assumes that the two parts of the network are contiguous, when in fact NGC's documents show that B6 and B7 are not in contiguous parts of the network. If we accept that the two parts of the network are not contiguous, but assume that the incremental cost and tariff differential are the same for the intermediate part of the network, the analysis we set out here would use different numbers but would reach the same qualitative conclusion.

Figure 3.1
Schematic Diagram of Investment and Constraints



NGC could remove this bias by calculating the unit costs (per MW-km) for the increase in installed capacity created by the investment (two new circuits at B6), rather than the increase in available capacity (one new circuit at B6) that is limited by constraints on other parts of the network.

Alternatively, to reflect network conditions, NGC could add in the cost of other work (at constraint B7) that would free up the full capacity created by the project.[7]

Correcting for this bias significantly reduces the actual unit cost of the project and implies that NGC may be overstating the incremental cost of capacity.

3.2. Revised Cost Comparison

Given the limited amount of information offered by NGC, the comparisons in Table 2 are impossible to audit. However, using NGC's assumptions applied to hypothetical example, we have recalculated the unit cost comparisons in a way that removes the bias identified above. As a result, investment costs per unit of capacity drop sharply, relative to the tariff differential calculated by NGC's model.

In Table 2, NGC assigns project B6 an (annuitised) cost of £11.2/kW-yr - far in excess of the tariff differential (i.e. the estimated incremental cost) for this part of the transmission grid, which NGC sets at £3.9/kW-yr. However (continuing the reference to our stylised example in Figure 3.1), this comparison ignores the capacity created between A and B that cannot be used because of a constraint between B and C.

[7] If they were correctly calculated, the tariff model expansion factors might provide a suitable basis for doing so.

A fairer comparison would have included the cost of additional reinforcement from B to C, for which the project at B7 provides a possible measure.[8] Including both the costs of this project and the additional capacity freed up at constraint B6 substantially reduces the cost per unit of expanding capacity. We show this calculation in Appendix A.

In Table 2, NGC compared an annual cost of £11.2/kW with a tariff differential of £3.9/kW, implying that the expansion coefficient is low. For our example, we calculated that NGC should have compared an annual cost of £7.3/kW with a tariff differential of £7.8/kW, which means that the expansion coefficient overstates the true incremental costs. Our comparison is only one example, but NGC would have had the information need to adjust all its comparisons of real projects on a similar basis, to remove the upward bias in estimates of incremental costs.

3.3. Conclusion

NGC's analysis of costs ignores the capacity created by certain investments, if such capacity cannot be used immediately due to constraints within other parts of the network. In contrast, the tariff model estimates only the cost of providing just sufficient capacity to accommodate the incremental flow over the network. NGC's comparison of these two figures is therefore biased, and overstates the actual costs of network reinforcements. Correcting for these biases would provide evidence for lowering the expansion constant and hence the tariff differential between zones.

[8] Tariff differentials based on marginal costs of adding capacity might provide an alternative method of estimating the required incremental cost, if one were convinced that they were cost-reflective.

4. Expansion Factors (s. 5.4)

NGC has estimated that the cost per unit of building new 275 kV lines is 1.8 times the cost of new 400 kV lines and that the cost per unit of building new 132 kV lines is 3.6 times that of 400 kV lines. In section 5.4, NGC repeats its claim that the cost of 400kV new build is a reasonable estimate of the cost of adding 400kV capacity by other means (which we dispute - see section 2). NGC then states simply that, "This is equally applicable to lower voltages",[9] without offering any evidence to support this contention. Since we maintain that the cost of adding capacity to existing 400kV lines is often lower than the cost of building new 400kV lines, it is necessary to examine in similar detail the costs of different methods to increase capacity at other voltages.

Given the different structures of the networks by voltage level, NGC considers the possibility of using "Transmission Owner specific expansion factors".[10] NGC accepts that such an approach would be more "cost-reflective", but says that "it could be seen as contrary to the other principles underpinning the GB methodology where modelling assumptions and factors are applied consistently across GB with no regional differentiation".[11] However, we are not aware of any "principle" that requires the same numbers to be used without regional differentiation, whilst "cost-reflectivity" and (more importantly) economic efficiency would require such regional differentiation, whenever empirical data provide an objective basis.

NGC provides no proper evidence or reasoning to support its claim that other methods of adding 132kV and 275kV capacity cost as much as building new 132kV and 275kV capacity and refers to a non-existent principle to justify using a common factor throughout Great Britain.. NGC's reluctance to accept the potential for cheaper methods to create capacity leads to overstatement of expansion factors for 132kV and 275kV lines and to an unjustified widening of tariff differentials between zones in Great Britain.

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[9] NGC (Dec 2004), p. 18.

[10] NGC (Dec 2004), p. 18.

[11] NGC (Dec 2004), p. 19.

5. Spare Capacity (s. 5.5) and Security Factor

In our previous reports in July 2004 and September 2004, we explained that any realistic calculation of marginal costs would take into account the existence of spare capacity within the network. NGC's transmission charging methodology for England and Wales takes account of spare capacity, but NGC proposes to remove this feature from the GB transmission charging methodology. NGC has since claimed that its methodology "implicitly" takes spare capacity into account, but NGC's explanation contradicts this assertion. As a result, we continue to find that NGC's methodology overstates the marginal cost of transmission by not taking spare capacity into account.

5.1. NGC's Treatment of Spare Capacity

NGC initially stated that it would be appropriate to retain the current treatment of spare capacity in the GB charging methodology.[12] Our earlier report showed that decisions about the identification and treatment of spare capacity could have a significant effect on tariffs. NGC's recent decision to remove any allowance for spare capacity when switching from England/Wales to GB therefore requires careful justification. So far, NGC has not provided any such justification.

NGC has argued that the position with regard to "generator spurs" (lines linking a generator to the rest of the network) has changed recently and that this change merits a different approach to the tariff calculation. According to NGC, generator spurs will often have available capacity in excess of that required by the generator and the resulting tariff calculation would fail to reflect costs, if generator spurs were always given special status due to this spare capacity.[13] However, generator spurs are a relatively minor part of the transmission network. The position of such lines need not determine the treatment of spare capacity for the network as a whole, or indeed for other parts of it. In the England and Wales transmission charging methodology, NGC recognises spare capacity by reducing the apparent length of the associated circuit to 75% of its actual length in the model[14] If NGC seriously believes that there is a problem with generator spurs, it ought to be possible to apply the circuit length reduction only to circuits that are *not* generator spurs.

However, NGC's argument calls into question the whole basis of the charging methodology. On one hand, NGC describes the locational element of the GB transmission charging methodology as intended to signal the marginal costs of *future* investment requirements. Here, the existence of spare capacity leads to an unequivocal reduction in marginal costs, because the need for investment is either avoided or substantially delayed. On the other hand, NGC's comments about the desire to charge for generator spurs reveal a separate desire to include the cost of *past* investments in the locational element of transmission charges - a substantial departure from previous statements of intent. For the sake of transparency and predictability in the tariff methodology, these different and conflicting views need to be reconciled.

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12 NGC (2003), GS Transmission Charging: Initial Thoughts, 16 December 2003, p. 16.

13 See NGC (Sep 2004), GB Transmission Charging: Final Methodologies - Conclusion Report to the Authority, 30 September 2004, p. 41.

14 NGC (2003) p. 16.

5.2. NGC's Claim that Spare Capacity is "Implicitly Includes"

One consequence of NGC's different and conflicting views over the appropriate basis for costing capacity is confusion over the actual treatment of spare capacity. NGC states that spare capacity is "implicitly included" in its current Investment Cost Related Pricing (ICRP) methodology[15] and provides an example to support this statement. NGC notes that "the Authority concluded that there is some merit in the arguments presented as to why Option A and Option B already reflect the presence of spare capacity on particular circuits".[16] However, the Authority was not in a position to draw any final conclusion on the issue since, as NGC reports, "the Authority note[d] that [NGC's arguments] have not been presented clearly or consistently to date".[17] Given this observation and the Authority's invitation for NGC to "review the issue, and if appropriate refine the approach",[18] the Authority's "conclusion" appears to be less than final.

We would reiterate the need to revisit the treatment of spare capacity, since NGC continues to misinterpret key economic aspects of the issue. In response to the Authority's request, NGC provides an example to illustrate its contention that the methodology implicitly takes spare capacity into account. However, the example and related explanation on page 22 merely confirms that the methodology *does not* in fact take spare capacity into account. This finding is easily confirmed by examining the effect of removing the spare capacity in the example; the tariff applied to the entry point in question would not change. Thus, the calculation does not depend on, or take account of, the existence of spare capacity. (See Box 1 below.)

NGC's example uses "incremental cost" in two distinct senses: the *replacement cost* of existing assets; and the *marginal cost* imposed on the system by an increase in usage. In the example, NGC calculates the replacement cost of the capacity required for actual usage of the network, and the replacement cost of the full amount of capacity that happens to be available (which includes some spare capacity). NGC then argues that the tariff calculation reflects the former and not the latter. However, the replacement cost of available capacity is not a standard that has any meaning, either within the context of NGC's alternative methodologies or within tariff calculations by other electricity transmission companies.

If NGC wishes to recover the costs of existing capacity (i.e. the cost of *past* investments), spare capacity might raise its charges, but tariffs would then (as in some transmission systems) reflect the actual costs of the assets concerned, not their replacement costs. If NGC's method is intended to signal the marginal cost imposed by increased usage (i.e. the cost of *future* investments), the availability of spare capacity would depress estimates of marginal cost, not raise them, since the existence of spare capacity avoids (or delays) the need for investment.

Thus, NGC's example not only shows that the model does not take spare capacity into account; it also illustrates how NGC offers two competing and mutually exclusive justifications for its cost calculation.

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15 NGC (Dec 2004), p. 21.

16 NGC (Dec 2004), p. 21.

17 Gas and Electricity Markets Authority (2004), *NGC's proposed GB electricity transmission charging methodologies The Authority's decision*, December 2004, p. 43. The Authority's point is noted by NGC (NGC (Dec 2004), p. 21).

18 Gas and Electricity Markets Authority (2004), p. 43.

Box 5.1
NGC's example showing that the tariff includes spare capacity

NGC gives an example in which a 400kV line links a generator to the main network 10km away. NGC measures the cost of this line at the expansion constant of £9.78/MWkm, which is the *average replacement cost* of the line (i.e. the expansion constant calculated as the unit cost of building new 400kV overhead lines). However, when there is spare capacity, the *marginal cost* of an additional MW of output is in fact zero (or at least rather lower than the cost of new build), because spare capacity avoids the need for investment (or at least delays the need for investment by several years). Hence if NGC were setting the charge for this line to reflect the marginal cost imposed by an additional 1 MW of usage, the charge would be zero (or low), not £9.78/MWkm.

NGC compares the tariff for the use of 100 MW (at the average replacement cost of £9.78/MWkm) with the equivalent average replacement cost for the total available capacity of 200 MW. Instead, NGC should compare the tariff charge with NGC's actual *marginal cost*, which would be zero (or low) in the example shown.

To see that NGC's cost methodology does not take spare capacity into account, we just need to show that the tariff does not change when we remove the spare capacity in NGC's example:

- If the capacity rating is 200 MW, the tariff, following NGC's methodology, is £9.78/MWkm and the total charge is £9,780 (= £9.78/MWkm * 10km * 100 MW);
- If the capacity rating were instead 100 MW, the tariff is still £9.78/MWkm and the total charge is still £9,780 (= £9.78/MWkm * 10km * 100 MW).

NGC claims that "the effect of spare capacity is already recognised in the locational element of the tariff".[19] However, the tariff charged to the generator is the same whether there is spare capacity or not. This claim is therefore false.

5.3. The Security Factor

The effect of ignoring spare capacity is compounded by NGC's addition of a locational security factor, which effectively scales up the differential between zones by a factor that has varied over the last two years between 1.8 and 1.9. (For the purpose of the illustrative tariffs, NGC is currently using 1.8.[20]).

The derivation of this factor remains obscure, being carried out in a separate "Secured DCLF" model known as SECULF. In November 2004, NGC issued a 2-page paper to the "DCLF users forum" (a group of those interested in the load flow modelling NGC uses to set its charges). The paper[21] explained the use of this model very briefly.

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[19] NGC (Dec 2004), p. 22

[20] NGC (Dec 2004), p. 31

[21] NGC (Nov 2004), Security Factor Calculation, DCLF Users Forum, 11 November 2004.

As far as we can ascertain from this document, NGC uses SECULF to estimate the extent to which contingencies (i.e. removal of certain lines) creates a need for additional investment within the transmission network. NGC first sets up the SECULF model with the network "intact" and examines the incremental flows over each line attributable to a net injection at one node. NGC then re-runs the model repeatedly with different lines taken out of action (i.e. for various "contingencies"); to see how the net injection affects line flows in these different conditions. When carrying out these repeated runs, NGC notes the maximum flow recorded on each line. NGC describes the sum of these maximum line-flows, multiplied by the length of each line, as the "secured nodal marginal cost" (although it is actually a measure of usage or capacity requirements, rather than of costs).

As described, this model does not take account of spare capacity, i.e. whether the maximum line flow recorded in the model exceeds existing capacity or not. If the maximum line flow does not exceed existing capacity, the line flow would not in practice impose any marginal cost for adding capacity. Adjusting the "secured nodal marginal cost" to take account of spare capacity as in the tariff methodology for England and Wales would result in a lower security factor for Great Britain.

NGC's paper states that the method involves a calculation of a system-wide security factor derived from a comparison (using regression techniques) of marginal costs in the "intact" and "secured" scenarios. It is likely that the factor would differ considerably between regions (or at least between TO networks), if NGC took spare capacity into account. However, we are hampered in our ability to comment more fully on the security factor by the opacity of NGC's explanation and that fact that NGC has not provided sufficient data to support it.

5.4. Conclusion

NGC's failure to take account of spare capacity leads to a twofold increase in NGC's estimate of incremental costs and hence in the difference between transmission charges at any two nodes.

First, NGC's basic cost calculation takes no account of spare capacity when assigning a marginal cost to incremental power flows and therefore overestimates marginal costs. NGC has previously taken spare capacity into account in the England and Wales charging methodology. NGC's reason for omitting this adjustment now relates to generator-only spurs, but this argument provides no justification for failing to recognise spare capacity on other parts of the network. Ignoring spare capacity raises tariff differentials without good reason. Moreover, if the level of spare capacity differs between Scottish networks and NGC's network, it would affect marginal costs at different points on the network and hence alter the "cost-reflective" differentials between tariffs at different points.

Second, NGC compounds the effect of the omission by ignoring the presence of spare capacity when modelling "contingencies", for the "secured" estimates of load flows and capacity requirements. As a result, the locational security factor is higher than it would otherwise be.

We note also that NGC's failure to account for spare capacity is inconsistent with the stated principles of the Investment Cost Related Pricing (ICRP) methodology. In NGC's "Initial Thoughts" paper in December 2003, NGC stated, "[The ICRP] model calculates the marginal costs of investment in the transmission system required as a result of an increase in demand

or generation at each node on the transmission system, based on a study of peak conditions with generation scaled to match demand."[22] As we have shown, NGC's tariff model does not in fact reflect marginal costs, since it makes no allowance for the reduction in marginal costs due to spare capacity.

NGC also uses a system-wide estimate of the security factor, when closer inspection might reveal that spare capacity was more prevalent, and hence the need for investment was lower, in some parts of the GB transmission network than in others. However, NGC does not provide sufficient information to assess whether it would be efficient or more cost-reflective to set different security factors for different parts of the transmission network.

[22] NGC (2003), p. 14.

6. Impact on Scottish Generators

6.1. Previous Statements on this Topic

In NGC's August report, NGC stated the following in reference to our report from July 2004:

> *"The* [sic] *is no evidence that the tariffs associated with Scenario B would not facilitate competition:*
>
> - *According to independent analysis* [i.e. NERA[23]] *Scottish generation is broadly neutral post BETTA compared with pre-BETTA, in terms of transmission charges when all charges, including connection and interconnector charges are taken into account.*
>
> - *The pre and post BETTA comparison is further aligned if the pre BETTA situation included an interconnector upgrade, the charges for which would be targeted directly to exporting Scottish generation.*
>
> - *Significant tariff differentials exist in England and Wales and have not been perceived as a barrier to competition."*[24]

In the passage from our July report to which NGC refers, we calculated the total monetary impact on Scottish generators. At that time, we estimated the increase in total transmission charges to Scottish generators attributable to Option B of the transmission charging methodology in NGC's April 2004 document ("the April TCM") to be £95 million per year. This impact would be offset by savings to Scottish generators deriving from (a) the redefinition of the connection boundary under NGC's "plugs" methodology, and (b) the removal of the Anglo-Scottish interconnector charges. (These costs are recovered through transmission charges under NGC's new TCMs for Great Britain.)

Ofgem[25] estimated the annual savings due to redefinition of the connection boundary at £25 million in 2005/06, and the savings due to the removal of the interconnector charges at £62 million per year, giving a saving of £87 million per year in total. Our estimated increase in total costs for Scottish generators was therefore £8 million per year (£95 million increase in transmission charges less savings of £87 million).

6.2. Effect of NGC's New Proposals on Scottish Generators

We have now re-calculated the effect of the indicative proposed tariffs arising from NGC's latest (20 December 2004) transmission charging methodology ("the December TCM"). We estimate that these proposals would increase annual transmission charges on Scottish generators by £109 million, as shown in Table 6.1.

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[23] NGC did not stipulate in its August report that the "independent analysis" it referred to was NERA's, however NGC clarified the point in its September consultation, stating that, "the independent study in support of the conclusion that post-BETTA and pre-BETTA transmission charges in Scotland would be broadly neutral, was the NERA report commissioned by Scottish Power and published on 26 July 2004", (NGC (Sept 2004), p. 55).

[24] NGC (Aug 2004), p. 5.

[25] *Presentation by Colin Sausman*, BETTA Project, Ofgem, 5 February 2004.

This £109 million increase in transmission charges would still be offset by the annual savings estimated by Ofgem to be £87 million (due to abolition of interconnector charges and the change in connection charges), leaving an estimated increase in total costs to Scottish generators of £22 million per year.

If we exclude any benefit from abolition of interconnector charges, the total effect on Scottish generators (comprising the increase in transmission charges of £109 million per year *less* the £25 million annual savings due to redefinition of connection charges) is a cost increase of £84 million per year.

Table 6.1
Increased Transmission Charges on Scottish Generators (December TCM)

Zone	Zone Name	Current TNUoS (plus Plugs) £/kW (A)	Dec TCM TNUoS £/kW (B)	Difference £/kW (C)=(B)-(A)	2004/05 Capacity GW (A)	Increase in Transmission Charges £m (E)=(A)*(D)
1	Peterhead	5.2	18.9	13.7	1.8	25
2	Strathbora	5.2	23.9	18.6	0.1	2
3	Northern Highlands	5.2	22.1	16.9	0.3	5
4	Skye	5.2	24.9	19.7	0.1	1
5	Western Highlands	5.2	20.2	15.0	0.2	3
6	Central Highlands	5.2	16.5	11.3	0.2	2
7	Southern Highlands	5.2	14.5	9.3	0.1	1
8	Mid Scotland	2.5	12.9	10.4	3.1	32
9	South Scotland	2.5	12.1	9.6	3.9	38
	Total				9.8	109

6.3. Impact on Competition

To assess the effect of these changes on competition, however, it is necessary to consider at least the differential impact of the changes on Scottish generators compared with their competitors in England and Wales. In our July report, we did not estimate the impact on generators in England and Wales.

Using data from the Seven Year Statement, we estimate current annual transmission revenues received from generators situated in England and Wales[26] to be about £208 million. We estimate the corresponding revenue under the December TCM to be about £148 million, a saving to generators situated in England and Wales of £60 million. Thus, given the increase in their costs of £22 million, generators situated in Scotland are £82 million per year worse off relative to their competitors in England and Wales.

[26] I.e. excluding revenues charged to users of the Scotland-England interconnector.

In **Error! Reference source not found.**, we have attempted to estimate the impact *by zone* of the new transmission charges, and the changes to interconnector and connection charges, on generators throughout Great Britain. For Scotland, we increased the current TNUoS charges by our estimate of the interconnector charge per kW. We also deducted the annual savings of £25 million due to redefinition of connection charges by spreading it *pro rata* over each zone in proportion to generation capacity and reducing the total transmission charge accordingly.

Table 6.2
December TCM: Impact on GB Generators

Zone	Zone Name	2004/05 Capacity	Dec TCM TNUoS	Current TNUoS Plus Savings (Interconnector & Connection Charges)	Costs under Dec TCM	Costs under current TNUoS Plus Savings	Increase in costs	
		GW	£/kW	£/kW	£m	£m	£m	%
1	Peterhead	1.8	18.9	14.1	34	26	9	34%
2	Strathbora	0.1	23.9	14.1	2	1	1	69%
3	Northern Highlands	0.3	22.1	14.1	6	4	2	56%
4	Skye	0.1	24.9	14.1	1	1	1	76%
5	Western Highlands	0.2	20.2	14.1	4	3	1	43%
6	Central Highlands	0.2	16.5	14.1	4	3	1	17%
7	Southern Highlands	0.1	14.5	14.1	2	2	0	2%
8	Mid Scotland	3.1	12.9	11.4	40	35	5	13%
9	South Scotland	3.9	12.1	11.4	47	45	3	6%
10	Northern England	3.5	8.2	9.0	29	31	-3	-9%
11	Lancashire, Pennines, Humber	16.7	4.9	5.4	82	89	-7	-8%
12	Wylfa	1.0	5.7	7.0	6	7	-1	-19%
13	Dinorwig	1.1	8.2	10.7	9	12	-3	-23%
14	North Wales & Cheshire	3.1	2.4	4.1	7	13	-5	-41%
15	South Yorkshire & Lincolnshire	7.2	3.3	3.5	23	25	-2	-6%
16	Midlands & South East	19.7	1.1	2.2	21	44	-22	-51%
17	North London	1.8	-0.3	1.7	-1	3	-4	-117%
18	Central London	0.1	-5.8	-6.6	-1	-1	0	12%
19	South Wales & Gloucester	0.6	-3.6	-2.2	-2	-1	-1	-68%
20	Oxon & South Coast	5.3	-1.2	-1.2	-6	-7	0	5%
21	Wessex	2.6	-5.1	-3.8	-13	-10	-3	-33%
22	Peninsula	0.1	-8.2	-6.8	-1	-1	-0	-20%
23	South West Wales	2.1	-2.5	-2.2	-5	-5	-1	-17%
	Scotland	9.8	14.4	12.2	140	119	22	18%
	England & Wales	64.9	2.3	3.1	148	200	-52	-26%
	Great Britain	74.7	3.9	4.3	289	319	-30	-9%

Note: Four of the new zones for England and Wales overlap several of the old zones. For these new zones, we had to define a current (2004/05) transmission charge. We have calculated each such transmission charge as the simple (unweighted) average of the transmission charges in all the old zones which the new zones overlap. For instance, if proposed zone A covers an area previously covered by part or all of zones B, D and E, then we calculate the current transmission charge for zone A as the average of current transmission charges for zones B, D and E. Zones This approach applies to zones 11, 15, 16 and 20, for which the average is calculated from current transmission charges with the following ranges: (11) £2.89 to £4.12 /kW; (15) £0.00 to £7.01/kW; (16) £1.73 to £2.89; (20) -£2.15 to -£0.00/kW.

For the proposed zones in England and Wales, we could only approximate the current TNUOS charge by taking a simple average of the charges for zones covered (in whole or in part) by the proposed new zones. The result is an underestimate of total transmission charges in England and Wales for 2004/05 by about £8 million. (The table shows £200 million

instead of £208 million.) However, even these approximate results show an interesting pattern by zone.

The proposed charges increase costs for Scottish generators and reduce costs for E&W generators. The combination of changes in transmission charges, interconnector charges and connections charges leads to an increase in costs in every Scottish zone and a decrease in costs in every zone in England and Wales, except for two minor cases where the effect is approximately zero.

6.4. Conclusion

Using Ofgem's estimate of the connection and interconnector charges that Scottish generators will avoid in future, we estimate the total increase in annual costs for Scottish generators to be £22 million. If we leave out the saving to Scottish generators due to abolition of interconnector charges, we calculate the total increase in costs for Scottish generators as £84 million per year.

At the same time, we estimate that generators in England and Wales would pay about £60 million per year less for use of the network. Thus, the combined effect would make Scottish generators £82 million per year worse off relative to generators in England and Wales (or £164 million per year if we exclude the saving on interconnector charges).

This shift in costs will change the relative incentives for continuing to operate existing plant or opening new plant, with Scottish generation facing a disadvantage relative to generators in E&W. This impact will therefore affect competition between generators on either side of the border. However, there does not appear to be any particular reason why a change in the tariff charging methodology should be accompanied by such a significant shift in costs from generators in England and Wales to generators in Scotland, and NGC has not provided an objective justification for this change in incentives.

7. Gaps in NGC's response

7.1. Information Not Yet Provided by NGC

In the three reports we have written on NGC's proposals on the transmission charging methodology, we have indicated a number of areas where NGC could provide more data in order to improve the transparency of its information and to provide evidence for some of its findings.

The information we have requested from NGC includes the following (although this list may not be complete):

1. Derivation of the expansion constant

We requested that NGC provide information on the internal operation of its DCLF model (NERA (July 2004), p.33). This should be accompanied by the data on costs which underlies the calculation of expansion constant (NERA (Sept 2004), p.3).

2. Costs assigned to the different methods of expanding capacity

We requested information in relation to the costs on the various methods for increasing capacity, including for instance: separation of "re-conductoring" costs into "bundling" and "restringing", an explanation of why NGC has not discounted the costs of future investment in the case of new build to reflect long lead times, and data on costs on the potential types of projects for uprating voltage (e.g. uprating a circuit in the middle of a 275kV network vs. upgrading a 275kV circuit already linked to a 400kV network)

3. Weights assigned to the different methods of expanding capacity

We requested information regarding the weighting for different methods of system expansion (NERA (Sept 2004), p.4). NGC has provided some information in their December 2004 report, however in this report we have also mentioned that NGC should provide justification for the low rating it ascribes to reprofiling, data on how NGC's assessment that 50% of potential reprofiling projects prove to be feasible relates to the 20% weighting given to reprofiling, and an explanation as to why a prudent operator would use methods more expensive than new build and other methods in 30% to 50% of all cases.

We have also suggested that NGC should describe the application and effect of loadflow control equipment in increasing capacity.

4. Scaling of generator capacity

In our July document (NERA (July 2004), p. 48), we described how NGC had failed to consider the variability of hydro capacity in applying its uniform scaling factor for generation.

5. Spare capacity

We have requested information on the amount of spare capacity available on the network and the effect of changing the treatment of spare capacity on the calculation of marginal costs and the security factor.

6. The detailed methodology for defining zones

We have requested that NGC provide details on its methodology for defining new zones and how it calculates and compares marginal costs at each node.

8. Calculation of locational security factor

NGC did not provide adequate explanation for its methodology in estimating and modelling additional costs (NERA (July 2004), p49)

9. Justification for zonal cost band of +/-£1/kW

We have argued that NGC did not explain how it came to determine this cost band, and that its determination lacks an objective standard.

7.2. Issues NGC Continues to Ignore

In our September 2004 response to NGC's August publication, we pointed out several issues raised in our previous report (of July 2004) to which NGC had not responded. NGC continues to ignore the same points in its December document.

For convenience, we list here the points from our July report (with the page and paragraph references) that NGC continues to ignore:

- *decremental costs* (Page 46, Section 6.4) – we argued in our earlier report that tariffs (if intended to reflect marginal costs) should be based on decremental costs where there is spare capacity in the system, or where spare capacity would be created by an existing user's decision to reduce their network usage;
- *scaling of generation capacity* (Page 48, Section 6.5) – we argued that hydro and wind capacity should be scaled to reflect the higher uncertainty concerning the availability of these plant in peak conditions, compared to conventional thermal generation. NGC's first response on this issue (August Consultation, Page 24, Para 4) just reiterated its initial approach without considering our argument that this approach lacks objective justification; and
- *risk of inefficient reduction in generating capacity in Scotland* (Page 54, Section 7.1) – we argued that NGC's overstatement of the expansion constant and failure to reflect decremental costs in tariffs, combined with the extension of " Plugs" to the whole of GB, would lead to an increased risk of inefficient plant closures in Scotland.

8. Conclusions

We continue to find a number of faults or inconsistencies in NGC's methodology. Although NGC has attempted to address some of our earlier points, we find that the new evidence has in most cases strengthened rather than weakened NERA's previous criticisms. We draw the following specific conclusions:

- NGC has reviewed its calculation of the expansion constant by means other than new build and concluded the alternative means do not substantially lower the cost of adding capacity. However NGC has still not taken some low cost techniques into account (e.g. load flow controls) and appears to have overstated the cost of other techniques. This implies that NGC has overstated the cost of creating new capacity and therefore the differential in tariffs between zones.
- NGC compares annuitised project costs per unit of capacity created against tariff differentials. The tariff model estimates the costs of providing just the capacity needed to accommodate an incremental flow over the network. However NGC's calculation of unit costs includes the cost of creating capacity that cannot be used immediately, owing to constraints within other parts of the network. NGC's comparison of these two figures is therefore biased, and overstates the actual costs of network reinforcements.
- NGC provides no proper reasoning to support its claim that alternative methods for adding capacity cost as much as new build at 132kV and 275kV. Thisleads to a likely overstatement of expansion factors and to an unjustified widening of tariff differentials between zones.
- NGC's calculation takes no account of spare capacity when assigning a marginal cost to incremental power flows and therefore overestimates marginal costs. NGC's reason for omitting this adjustment now relates to generator-only spurs. However, this argument provides no justification for failing to recognise the effect of spare capacity on marginal costs in other parts of the network. NGC provides an example to illustrate its contention that the methodology implicitly takes spare capacity into account. However, the example appears to misinterpret marginal costs, and merely confirms that the methodology *does not* take spare capacity into account. The result is a methodology that does not apply the principles of Incremental Cost Related Pricing, as previously set out by NGC.
- The effect of ignoring spare capacity is compounded by NGC's addition of a locational security factor. NGC's model takes no account of the fact that if the maximum line flow recorded in the model does not exceed existing capacity then the line flow would not impose any marginal cost for additional capacity. As a result the locational security factor is higher than it would otherwise be.

Overall, these observations imply that NGC is overstating the expansion constant and factors without good reason. Thisleads to wider tariff differentials than those required by NGC's legal duties and stated objectives for it ICRP tariff charging methodology.

Appendix A. Revised Comparison of Costs and Tariffs

This appendix reviews the analysis in Table 2 of NGC's report and adjusts it to remove an implicit bias.

The first part of Table A.1 shows NGC's calculation for the standalone project. As in Figure 3.1, we assume that 1000 MW of capacity is added between A and B, but that total additional capacity available between A and B is constrained to 500 MW, due to congestion between B and C. NGC estimates the tariff differential for the B6 constraint to be £3.9/kW/yr, as shown in Table 2 in the NGC report. Table 2 in the NGC report also shows the annuitised unit project cost as £11.2/kW-yr, implying an annuitised total project cost of £5.6 million per year on the basis of an increase in available capacity of 500 MW.

The second part of Table A.1 shows a similar calculation except that it includes the cost of reinforcing the link from B to C, to provide an additional capacity on that part of the network of 500 MW in order to permit full use of the 1000 MW capacity created between A and B. For the increased capacity between A and B, the *total* annuitised project cost is the same, i.e. £5.6 million per year, but the annuitised project cost *per unit of capacity* falls by half to £5.6/kW/yr, since the total costs are spread over twice the additional units of capacity. As per Table 2 of the NGC report, we assume that the tariff differential is £3.9/kW-yr, and that the annuitised project cost per unit of additional capacity between B and C is £3.4/kW-yr. Assuming that this project increases capacity at B7 by 500 MW, the total annuitised project cost for the B7 project is £1.7 million per year, bringing the total cost for the combined B6 and B7 projects to £7.3 million per year. The cost per unit for the combined project producing 1000 MW of additional capacity is therefore £7.3/kW-yr, which is substantially cheaper than the combined tariff differential of £7.8/kW-yr implied by NGC's tariff model (=£3.9 for AB plus £3.9 for BC).

Thus, instead of comparing a tariff differential of £3.9/kW-yr with a project cost of £11.2/kW-yr, this extension of the project compares a tariff differential of £7.8/kW-yr with a project cost of £7.3/kW-yr . That result implies that NGC's tariff model overestimates actual costs, rather than under-estimating them as NGC implies.

This analysis could be amended by including cost and tariff differentials for more of the network (e.g. for the zones between B6 and B7). However, if we were to use the same figure for incremental costs and for tariff differentials, the numbers would change by the conclusions would not, i.e. incremental costs per unit would still lie below the tariff differential.

Thus, NGC's Table 2 biases the comparisons of actual projects against the tariff model, by failing to ascribe any value to capacity created between A and B, when a small investment between B and C would make such capacity available. Similar problems are likely to affect all of the comparisons in NGC's Table 2.

Table A.1
Relative Cost of Capacity Expansions

	Capacity Built	Increased Capacity Available	Tariff Differential	Annuitised Project Cost (per unit)	Annuitised Project Cost (Total)	Source (Indicative Project)
	(MW)	(MW)	(£/kW/yr)	(£/kW/yr)	(£m/yr)	
Standalone						
A-B	1000	500	3.9	11.2	5.600	B6
Complete						
A-B	1000	1000	3.9	5.6	5.600	B6
B-C	500	500	3.9	3.4	1.700	B7
Total		1000	7.8	7.3	7.300	

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