nationalgrid

Progress report on GB charging condition 2, Review of incremental cost of capacity within the GB Charging Methodology

April 2006

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1 Executive Summary

This progress report is in response to the requirement in condition 2 to the GB transmission use of system charging methodology to produce a report on progress in April 2006. The report allows interested parties to understand better how the incremental cost of capacity is calculated and gives those users who would not normally attend industry meetings the opportunity to contribute to the review prior to National Grid concluding and taking forward any changes to the methodology and / or statements through formal consultations as appropriate.

This review has covered many diverse and detailed areas of the methodology, the principles applied in the transport and tariff models and the detailed calculation process for the incremental cost of capacity and associated expansion factors. National Grid has engaged the industry through the Transmission Charging Methodologies Forum (TCMF) and its sub-group the Charging Issues Standing Group (CISG).

The next stage of this review will involve consideration of any issues or opinions raised in response to this report. Following this National Grid will discuss any final proposals at the TCMF prior to any formal consultation on changes to the methodology. In addition, National Grid will also discuss drafting for inclusion in the statement of GB use of system charging methodology to improve transparency of current practice with the TCMF prior to including in the annual update.

At this stage it is envisaged that the main area of change will be to improve transparency in the statement of the process and assumptions used in the calculation of incremental cost of capacity rather than actual changes to the methodology. Already included within the methodology is the ability to reflect regional differences to the costs of incremental capacity through regional expansion factors. These factors, along with the actual incremental cost of capacity, will be updated in-line with the process for calculating tariffs for the financial year 2007/08, the first year of a new price control period.

On the central issue of the cost reflectivity of the incremental cost of capacity and how it is used within the methodology, the analysis carried out and the industry discussion at a number of forums leads National Grid to believe the current process is cost reflective in the context of the methodology as a whole, considering all the factors that impact on the ability to meet the relevant objectives, such as transparency, simplicity and the need to reflect future rather than historic costs in the locational signal to encourage efficient decisions.

National Grid has reviewed the assumption that the cost of 400kV overhead line new build can be considered as a proxy for the all the techniques for providing additional capacity. National Grid continues to believe this a reasonable assumption in the context of the methodology and models used to implement the methodology, the DC load flow (DCLF) and tariff models.

However, it is clear that there is a general lack of understanding of the processes used and the assumptions made in the calculation of incremental cost of capacity. In order to address this National Grid has already carried out a tutorial on the methodology and calculation of incremental cost of capcity, with another planned in May 2006 due to the high level of interest. National Grid is also keen to update the statement of the use of system charging methodology with more information to improve the general transparency and understanding of the process of calculation of incremental cost of capcity and how it is used within the methodology.

2 Introduction

In approving the GB Use of System Charging Methodology[1] the Authority placed a number of conditions on National Grid which, in the view of the Authority, might be expected over time to result in a methodology which better meets the relevant objectives.

This report is published by National Grid as a requirement of condition 2. Condition 2 requires National Grid to review the technical basis for a range of alternative methods of estimating and reflecting in locational charges, the incremental cost of capacity. Condition 2 also requires National Grid to publish a progress report in April 2006. This report is intended to satisfy that requirement.

Having consulted with the industry through a number of meetings, including two workshops, the Transmission Charging Methodologies Forum (TCMF) and at the Charging Issues Standing Group (CISG), this report seeks to:

- inform the industry of how the incremental cost of capacity is calculated and used in the GB Use of System Charging Methodology;
- review the discussions with industry participants to date;
- review the options for change that have been discussed; and
- indicate areas that National Grid is considering consulting further on in summer 2006.

In response to this report, National Grid is seeking wider industry views on the issues contained within it. These views will be discussed at the CISG and considered in the preparation of any proposals prior to a formal consultation, likely to be during Summer 2006.

[1] 'NGC's proposed GB electricity transmission use of system charging methodology, The Authorities decisions, March 2005, 80/05'. Available on the Ofgem website.
'The Statement of Use of System Charging Methodology' is available on National Grid's industry information site, http://www.nationalgrid.com/uk/Electricity/Charges/chargingstatementsapproval/

3 Overview and responses

The main function of the Direct Current Load Flow (DCLF) transport and tariff model is to generate tariffs in accordance with the methodology which therefore leads to charges that meet the relevant objectives of National Grid as set out in the Transmission Licence. At a high level this is to generate tariffs that reflect, as closely as possible, the costs incurred by Transmission Licensees in investing in the transmission system. This requirement is balanced with the need to have a simple, transparent, predictable and stable methodology and tariffs that promote competition in supply and generation.

The DCLF Investment Cost Related Pricing (ICRP) methodology uses a DC load flow to approximate the Long Run Marginal Cost of investments in the transmission system for zones. The methodology can be thought of as two separate elements. Firstly, there is the DC Load Flow, commonly referred to as the transport model, which establishes the locational element. Secondly, there is the tariff model that converts the locational element from the transport model into a £/unit price and then calculates tariffs to ensure the correct overall cost recovery for the Transmission Businesses.

The DC load flow is based on a simplified model of the transmission system, taking account of the general topology of the transmission system and impedance of each circuit. To begin with, it creates a base case representing the flows required for generation to meet demand at system peak. The sum product of flows and length of each line provides a system usage measure in MWkm. The model then injects an additional MW at each node on the system in turn, each time taking a MW off at a common reference node. The additional MWkm over the base case is taken as the incremental MWkm of circuit capacity required to accommodate the additional MW at that node – the nodal marginal km. Note the additional MWkm could be negative i.e. total MWkm is less than the base case.

A fundamental principle of the methodology is that it provides 'smoothed' incremental costs i.e. removes the lumpiness associated with transmission investments. It achieves this through decoupling actual investments from actual Users and assuming linearity based around the small increment. It also assumes that the effect of the increment will be equal but opposite for changes in demand, compared to changes in generation. Understanding these fundamental principles is very important when assessing the level to which the incremental cost of capacity is cost reflective.

Another issue that is very important in the context of condition 2 is that seeking absolute cost reflectivity has to be considered alongside the need to promote competition and maintaining a simple and transparent methodology. In assessing changes to the methodology Users and National Grid, to the extent that they affect the relevant objectives, also consider stability and predictability of charges as elements that would promote competition.

The incremental cost of capacity is used to convert the marginal km (after being grouped into zones) into a £/unit price within the tariff model. The incremental cost of capacity, expressed in £/MWkm, represents the annuitised value of transmission infrastructure capital investment required to transport one MW over one km. Closely associated with and calculated in the same manner are the expansion factors used within the DC load flow model. These factors are used to reflect the cost of providing transmission capacity at voltages other than 400kV and with cable rather than overhead line (OHL). In this report when referring to the calculation of incremental cost of capacity we are, unless stated otherwise, also referring to the calculation of expansion factors.

Interested parties are asked to comment on the issues contained within this report to aid National Grid with the development of consultation proposals to improve the Use of System Charging Methodology. National Grid requests that Users respond to this report by 31st May 2006. Please do this preferably by email to:

patrick.hynes@uk.ngrid.com

or alternatively by post to:

Patrick Hynes
Electricity Charging and Access Development
National Grid House
Warwick Technology Park
Gallows Hill
Warwick
CV34 6DA

If you have any queries on any of the issues within this report please contact Patrick Hynes at the above email address or on 01926 65 6319.

4 Licence requirements

As the transmission licensee authorised to co-ordinate and direct the flow of electricity onto and over the transmission system within Great Britain, National Grid has the duties to develop and maintain an efficient, co-ordinated and economical transmission system and to facilitate competition in generation and supply. Along with these high level duties National Grid is also required to have a charging methodology that achieves the following relevant objectives:

a) To facilitate effective competition in generation and supply.
b) To reflect, as far as reasonably practicable, the cost incurred by transmission licensees in their transmission businesses.
c) In so far as is consistent with a) and b) above, and as far as reasonably practicable, they properly reflect developments in transmission licensees' transmission businesses.

The licence framework used to introduce BETTA also allowed the Authority to make the GB methodology established for BETTA conditional. The Authority exercised that right and placed 6 conditions along with approval. 5 associated with the Use of System Methodology and another associated with the Connection Methodology. Condition 2 is:

> *‘To review, identify and asses further the technical basis for a range of alternative methods (including the method adopted in the approved methodology) of estimating, and reflecting in locational charges, the incremental cost of capacity. NGC should consult with interested parties to identify a range of alternative methods to form part of this technical assessment. If the review identifies potential improvements to the existing methodology, NGC should bring forward modification proposals no later than April 2007. A report on progress shall be published in April 2006. In the event that NGC concludes that there are no further improvements, NGC should publish a report setting out the conclusions of the review.’*

At the CISG in January 2006 Ofgem confirmed that the original focus of condition 2 was in relation to what is termed in this report as the ‘range of techniques for providing additional capacity’.

5 Background

5.1 What is incremental cost of capacity?

Incremental cost of capacity is simply a measure used to represent the cost of transmission investment. It converts the MWkm output from the transport model into a cost for use in the tariff setting process. This is commonly referred to as the locational element of the TNUoS tariff.

The incremental cost of capacity, expressed in £/MWkm, represents the annuitised value of transmission infrastructure capital investment required to transport 1 MW over 1 km. It is ‘based’ against 1MW and 1km so that it can be used in conjunction with the output from the transport model, and is intended, as far as possible, to provide a forward looking signal.

5.2 What are the expansion factors?

Closely associated with and calculated in the same manner as incremental cost of capacity are the expansion factors used within the DC load flow model. These factors are used to reflect the cost of providing transmission capacity at voltages other than 400kV and with cable rather than OHL.

The basic transport model uses impedances and a simplified network topology to calculate the flow paths from generation to load. The actual voltage or distance of any element on the system is not directly used in determining flows. Therefore the output of the DC load flow is taken as MW. To convert this flow in to MWkm the flow on each line is multiplied by the length of the line.

In practice, the system is made up of different voltages and different types of circuit (OHL or cable) which all have different £/MWkm costs. In order to produce a representative cost of expanding the system at the different voltages or by other types of circuit, the costs of these circuits need to be normalised against the cost of a 400kV line. The methodology does this by the use of expansion factors. Expansion factors are calculated by taking a £/MWkm price for each voltage or circuit type in the same way as for 400kV OHL, and dividing these by the 400kV OHL constant.

For example, if the cost of a 400KV OHL was £10/MWkm and the cost of a 400kV cable was £200/MWkm, the expansion factor for the cable would be 20. Table 1 below shows the current expansion factors calculated with data provided by the Transmission Owners during the BETTA process.

Table 1 GB Expansion factors

Expansion Constant Parameters				
Projected Relative Cost of Asset	**Pure GB**	**NGC**	**SPT**	**SHETL**
400kV cable factor	20.664	20.664	20.664	20.664
275kV cable factor	20.883	20.701	20.701	20.701
132kV cable factor	27.850	27.850	27.850	25.483
400kV line factor	1.000	1.000	1.000	1.000
275kV line factor	1.736	1.125	1.125	1.125
132kV line factor	2.614	2.614	2.614	2.081

In table 1, the factor for the 400kV line is shown as 1.00 as it is the base cost. As all the other factors are greater than 1.00 this indicates 400kV OHL is the most economic way of providing additional capacity, in terms of £/MWkm.

The 132kV and 275kV factors have been adjusted by an ‘upgrade’ factor. This acknowledges that a certain percentage of investment on the current 132kV and 275kV systems will actually be provided through upgrading circuits to a higher voltage (assumed to be 400kV in both cases). Calculation of the upgrade factor is an integral aspect of the expansion factor for any voltage.

As noted earlier, the GB methodology is ‘smoothed’ i.e. the lumpiness of providing additional capacity is not borne by any particular User. This leads to the signal derived from the methodology representing the capacity requested rather than that supplied (as would be the case with deep reinforcements).

For example, if the standard investment increment is 500MW, but a User only required 400MW, the signal derived from the transport model would only be based on the 400MW requested. The cost of providing the additional 100MW capacity would be recovered through the residual element of the tariff which is non-locational.

Although the locational signal is cost reflective it is not intended as a cost recovery mechanism and the cost reflectivity is linked to the impact of investment and expected use of the system rather than specific investment caused.

5.3 How is incremental cost of capacity calculated?

The incremental cost of capacity is calculated using historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs as forward-looking as possible. The data used is taken from an internal report, entitled TR3. The primary purpose of the TR3 document is to provide accurate costs for proposed schemes by National Grid. This provides the basis of central scheme costs used in the internal scheme sanctioning process. Given that the costs in TR3 represent actual costs incurred and National Grid’s best assessment of forward looking prices, they are considered commercially sensitive and are therefore treated as confidential. The calculation also relies on a significant amount of asset information sourced from National Grid’s internal asset register.

As described above, for each circuit type and voltage a separate calculation is carried out to establish a £/MVAkm figure. In order to simplify the calculation a unity power factor is assumed (giving £/MWkm), this assumption is discussed in more detail later in this report.

Table 2 below, shows the first stage in calculating the incremental cost of capacity. This shows a simplified calculation for 400kV OHL (the data is for demonstration only and not taken from TR3 or the asset data base).

Table 2 Calculation of 400kV OHL incremental cost of capacity

400kV OHL					
MVA	**Type**	£(000)/km	circuit km*	**£/MWkm**	**Weighted £/MWkm**
A	B	C	D	E = A/C	F=E*D
6500	La	700	500	107.69	53846
6500	Lb	780	0	120.00	0
3500	La/b	600	200	171.43	34286
3600	Lc	400	300	111.11	33333
4000	Lc/a	450	1100	112.50	123750
5000	Ld	500	300	100.00	30000
5400	Ld/a	550	100	101.85	10185
sum			**2500 (G)**		**285400 (H)**
				Weighted Average:	**114.160 (H/G)**

*** These are circuit km of that type that have been provided in the previous 10 years**

The weighted £/MWkm derived from table 2 is converted in to an annual figure by multiplying it by an annuity factor. The calculation of the annuity factor is shown below:

$$Annuityfactor = \frac{1}{\left[\frac{\left(1-(1+WACC)^{-AssetLife}\right)}{WACC}\right]}$$

The selection of appropriate figures for the WACC and asset life are discussed later in this report, they are currently 0.0625 and 50 years respectively. These assumptions provide an annuity factor of 0.066.

The final step in calculating the incremental cost of capacity is to add a share of the annual transmission overheads (maintenance, rates etc.). This is done by multiplying the Gross Asset Value (GAV) of the assets by an ‘overhead factor’. The factor represents the total business overhead in any year divided by the total GAV of the transmission system, and is shown as a percentage. This is recalculated at the start of each price control period when the incremental cost of capacity is recalculated. The overhead factor is currently 1.8%.

Following the example above, the final process in calculating the incremental cost of capacity is calculated as shown in table 3 below.

Table 3 Calculation of incremental cost of capacity

400kV OHL	
	Ave £/MWkm
OHL	114.160
Annuitised	7.535
Overhead	2.055
Final	**9.589**

This process of calculating the factors, along with the incremental cost of capacity for a 400kV OHL, is carried out for the first year of the price control and is increased by inflation each subsequent year of the price control period. Overall the methodology produce a stable forward looking rather than historic looking cost.

5.4 How is incremental cost of capacity used?

Incremental cost of capacity is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control).

The nodal marginal km derived from the tariff model is converted to a £/MWkm by first grouping each node within a zone and calculating the weighted average of each zone. The weighted average for each generation and demand zone is then multiplied by the incremental cost of capacity and the Security Factor; this converts the signal into a £/MW figure. The security factor is derived from a secured DC load flow and is currently 1.8. Within the tariff model it is assumed the effect for demand is equal but opposite to that of generation.

For example, if the average weighted zonal marginal km for a generation zone was 398MWkm the raw locational charge would be:

Raw zonal locational tariff = 398 km * 9.589£/MWkm * 1.8/1000
= 6.88£/kW

This raw zonal locational charge is calculated for each generation and demand zone. This is then multiplied by the charging base (National Grid's best forecast of the final invoice position). The total revenue for generation and demand at this stage will not reflect the generation and demand split of 27% recovery from generation and 73% from demand (commonly referred to as the 'G/D split'). In order to ensure the correct proportions are recovered the locational element is then 're-referenced'.

Re-referencing involves adjusting the zonal marginal km figures by a fixed quantity in the tariff spreadsheet to ensure the correct revenue collection in accordance with the G/D split.

The final tariff is calculated by apportioning the difference between the revenue collected through the locational element and the total allowed revenue between demand and generation in accordance with the G/D split on a non-locational basis.

6 Industry workshops

National Grid discussed the proposed approach for dealing with all the charging conditions at the April 2005 TCMF. In the case of condition 2 the approach was to hold an industry workshop to discuss the options.

6.1 First workshop

The objectives and format of the workshop were to identify alternative methods for estimating the incremental cost of capacity with a conclusion report to be presented to the May TCMF meeting. The format included a morning session to identify alternative options, followed by an afternoon session to assess the pros and cons of the options. Both sessions were run in industry led breakout groups, with each group's conclusions presented and discussed by all attendees.

The conclusion report from the workshop is available on National Grid's industry information website[2]. The areas that attendees suggested needed further reviewing were:

1. Forward-looking Vs historic costs / forecasting
2. Transparency
3. Cost reflectivity of expansion constant
4. Thermal ratings
5. Spare capacity
6. Dis-aggregation of calculation and application on a circuit specific, zonal or nodal basis
7. Commoditisation
8. Variable locational signals for generation & demand

This report focuses on those areas that relate to incremental cost of capacity rather than the wider issues relating to the methodology. Therefore commoditisation and variable locational signals for generation and demand are not discussed further in this report.

In further discussions at industry meetings it was noted that the main area that led to the condition was the cost reflectivity of the expansion constants. This report reviews the other areas but the main focus is on the cost reflectivity of the expansion constant.

At the workshop it was concluded that the remaining areas required further development and assessment, including the key issue of transparency. One particular observation made during the workshop was that transparency evolves over time and that when there is a significant change to the charging methodology, Users will tend to concentrate on the higher level issues. The

[2] http://www.nationalgrid.com/NR/rdonlyres/52D2AF99-DF8B-4CA1-A995-E3EDE8E553C7/2686/Workshop_Conclusion_Report.pdf

detailed knowledge and understanding develops afterwards when Users have become more familiar with the principles. The concept of transparency is individual to each User and can realistically only be delivered to everyone over a sustained period of stability of the methodologies.

Whilst a number of areas were identified for further assessment, initially it was felt that there would be considerable value in addressing concerns regarding transparency and understanding of the principles underpinning the current methodology. To achieve this, National Grid proposed to hold a second workshop to examine the existing methodology in detail. This would also identify any areas where further clarity or information may be beneficial to improve the transparency of the methodology. This workshop covered the whole methodology, but focused on the calculation of incremental cost of capacity.

A report was produced following the first workshop and placed on the industry website. In the report National Grid invited views from interested parties who were not able to attend the workshop to ensure all relevant issues were covered. No comments were received on the initial report.

6.2 Second workshop

The main aim of this workshop was to facilitate a better understanding of the existing charging principles and identify areas where transparency could be improved.

This workshop ran through the high level principles of the methodology and sought to provide additional details on the internal process used for calculating the incremental cost of capacity. This consisted of a number of presentations by National Grid followed by questions from attendees.

The general response to the workshop was positive. The industry feedback and National Grid's approach following the second workshop were discussed at the September 2005 TCMF. National Grid's interpretation, supported at the TCMF, was that attendees expressed the view that the workshop was useful in further building up industry knowledge, however there were no significant transparency holes in the methodology.

National Grid originally proposed a third workshop to be held to review and develop further the alternative options. However, following further consideration it was felt this could be best achieved through the Charging Issues Sub Group meetings (CISG, a sub group to the TCMF looking at detailed issues). In particular, the January 2006 CISG meeting, where National Grid provided the further assessment and initial conclusions covered in this report. The options, assessment and conclusions were presented and then discussed at length.[3] The discussion at CISG has also been used in preparation of this report.

[3] The CISG presentations and minutes are available on the National Grid electricity industry information web site. http://www.nationalgrid.com/uk/Electricity/Charges/cisg/meeting/

7 Industry discussions

The CISG is a sub-group to the TCMF. Its main purpose is to review the technical and detailed areas of the charging methodology.

At CISG on 31 January 2006, National Grid presented initial considerations and conclusions on the issues raised at the two workshops.[4] These were then discussed prior to agreeing the way forward. The rest of this report reviews the information provided to CISG and the discussions that took place.

Firstly, National Grid explained the basis of the current methodology for calculating the incremental cost of capacity and how it is used in the current Use of System charging methodology. This was a high level summary of the presentation given at the second workshop. Following this, National Grid went through the individual areas of the methodology that had been discussed at the workshops. For each of these, National Grid reviewed the main issues, the analysis undertaken and, where appropriate, the options available. Finally, for each area, National Grid opened the discussion up to the floor to seek further industry views.

7.1 Transparency

National Grid noted where further transparency could be added to the current charging methodology and also how amending the methodology might improve transparency.

One attendee commented that whilst there may be opportunities for improved transparency of the wider Use of System Charging Methodology, it may be more appropriate to deal with detailed queries on a bilateral basis. It was felt that the process and assumptions used in calculating the cost of incremental capacity was certainly one area where the industry may benefit from more comprehensive coverage in the Statement of the Use of System Charging Methodology.

With regard to the data used in the calculation, National Grid explained that the investment cost per MWkm is calculated using the costs derived from the TR3 document. This provides indicative costs derived from actual tender information, estimates from suppliers, or previous information indexed using transmission cost indices. It was explained that TR3 costs reflect general site conditions but specifically exclude various costs including land, engineering charges and associated equipment.

The TR3 document is regarded as commercially sensitive information as the figures contained in the document are derived from actual tender information and are used for budgetary and contracting purposes. The TR3 production process is subject to external auditing to ensure the legitimacy of the document.

[4] The presentation can be found on the National Grid electricity industry information website at http://www.nationalgrid.com/uk/Electricity/Charges/cisg/

An attendee enquired as to whether it might be appropriate for the industry to be introduced to the auditors responsible for auditing the document to uphold its legitimacy. Whilst this was considered, it was agreed that such action would not be necessary as there was little mistrust that the figures would not be legitimate. The wider concern was that the appropriate basis of calculation was correct, rather than the numbers used.

National Grid explained that overhead line costs are calculated on the assumption of a build greater than 30km comprising 70% suspension towers. The costs of river, road and rail crossings are excluded from these costs, as are miscellaneous costs such as under-grounding, telecoms, tree felling, soil reinstatement and surveying etc. The idea of these exclusions was to ensure the cost was generic and based on clear assumptions.

An attendee queried as to whether an assumption that 70% of towers over a circuit length of 30km is realistic as this would mean that almost one in three towers were something other than suspension towers, which seemed too high. National Grid has carried out further analysis and have confirmed that 70% of suspension towers is accurate. This figure takes account of tension, angle and terminal towers.

National Grid also explained that the current methodology used to calculate cable costs assumes direct burial. It was questioned as to whether this was an appropriate assumption to make in modern times considering that cable installation may be more likely to locate predominantly in urban areas. National Grid suggested that although clearly some cable or parts of cables would not be direct burial given the project and site specific issues involved, inclusion of additional costs would be very subjective and complex. On balance, National Grid considered that direct burial was a reasonable assumption that didn’t unreasonably dilute the cost reflectivity of the final tariffs.

One industry attendee questioned if it would be more appropriate to consider the relevant investment costs of the Scottish TOs in addition to those of National Grid contained in the TR3 document. National Grid commented that this was considered during the GB charging consultation process and that information received from the Scottish TOs indicated that the costs were comparable to those of National Grid.

7.2 Forward-looking v Historic costs

National Grid discussed whether it is more appropriate to use forward-looking costs or historic costs in calculating the incremental cost of capacity. In order to treat new and existing Users equally, National Grid believe that the methodology needs to be forward-looking, though recognises that there is significant scope for considering exactly how this is practically achieved without diluting cost reflectivity.

During the first workshop and at previous CISG meetings it had been suggested that National Grid should consider a Transcost type approach. Transcost models the future investment on the gas transportation system in

GB required over a 10-year period by incrementing the base plan assumptions for the supply and demand scenarios with a given volume of capacity to identify the likely levels of investment required throughout the National Transmission System.

A number of attendees expressed their unfamiliarity with the Transcost model and so National Grid agreed to make an overview PowerPoint presentation available from a previous Gas Charging Methodologies Forum.[5]

National Grid noted the similarity between Transcost and the Condition 5 report. National Grid does not currently have a tool that would predict future reinforcements similar to Transcost, although the signals in the Condition 5 report could be considered as similar. National Grid proposed that future Condition 5 reports should include analysis of how accurate historic predictions had been. If a reasonable correlation between actual tariffs and Condition 5 forecasts can be established, National Grid would then consider how such forward-looking signals could be incorporated into the methodology for establishing the marginal km measure e.g. a 5 year weighted average marginal km based on the system over the next five winter peaks.

It was considered whether it might be appropriate to limit the use of historic data by restricting this to a period of no greater than 3 instead of 10 years. Industry attendees suggested that such a move would not be in the interest of price stability. Under such a methodology, the costs would depend very much on the significant projects undertaken in the recent past and perhaps more significantly, the location of these projects.

A significant project undertaken in the centre of London for example, would heavily skew the costs over a three year period disproportionately, whereas over a ten year period, the skewing affect would be less dramatic. In addition, one could argue that although the investment had been made using signals that would be more cost reflective of recent historic commitments, it would not necessarily be more reflective of future investments. National Grid accepted this point and agreed that the current process, combined with the removal of project specific costs, was likely to be more stable. Also with the inclusion of indices within the TR3 costs the current methodology was more forward looking.

A perfect solution would be to predict the future cost of investments and the future investment required. Given that this was clearly not possible, National Grid considered that the current method based on average historic costs adjusted by known indices to reflect future trends was a reasonable solution and industry attendees generally agreed with this.

7.3 Thermal ratings

This area was focusing on the assumption within the methodology that the system operates at a unity power factor (1 MVA is equal to 1 MW). National

[5] These slide can be viewed at: http://www.nationalgrid.com/NR/rdonlyres/0FFB3435-7E52-4749-B422-71D3CA29F9E6/5868/OverviewofChargingCalculationModelsFinal.ppt

Grid noted it is considering the particular issues of investment in reactive compensation equipment as a separate issue. Whilst the incremental cost of capacity is derived from MVA figures, the DC Load Flow transport model produces a MW figure.

The discussion was opened up as to whether it might be appropriate to consider moving to an Alternating Current Load Flow (ACLF) model to incorporate the reactive power element within the methodology. Industry participants overwhelmingly indicated that whilst an ACLF model has its merits in terms of precision, a move to such a model would add a disproportionate amount of complexity to the methodology compared to the benefits that would be gained.

National Grid presented alternative methods that recognised unity power factor was a simplification. The first of the options covered was whether it might be appropriate to consider calculating the incremental cost of capacity on a MW basis rather than an MVA basis. The second approach would be to scale the charging base figure in the tariff model. Both of these alternatives would require an assumed power factor. For demand, the power factor could be a GB or a zonal average. For generation, it could be the higher of the Grid Code requirement or a commercially agreed figure. However it was noted the important figure was the system power factor not the load or generation power factor.

Following discussion on the options, it was generally felt that as the DCLF model does not deal with MVA and moving towards an incremental cost of capacity calculation on a MW basis would be more cost reflective, however the simplification in the current methodology was reasonable in the context of the simplified model used. National Grid indicated that the selection of a system power factor would be very subjective. AC analysis shows that each line has a different power factor and the power factor used for design to accommodate post-fault loads did not bear a linear relationship to the pre-fault condition. On radial spurs this concept might be robust where the end User power factor could be identified, but it was not appropriate for the wider system where the designed level was dependant on many interrelated factors.

National Grid acknowledges that separate from the incremental cost of capacity and condition 2 there is future scope for reviewing in more detail the reactive charging incentives provided through the methodology.

7.4 Spare capacity

Calculated on a £/MWkm basis, the incremental cost of capacity calculation does not include spare capacity on circuits. The DCLF transport model calculates an unconstrained marginal km figure and therefore the historical cost of spare capacity is incorporated in the residual element of the TNUoS tariff, thus allocated across all Users equally. In terms of the forward-looking signal, it was noted that the issue of spare capacity was discussed at great length during the GB charging consultation process.

It was also noted that a fundamental feature of the current methodology is the linear signal that it provides. One aspect of this is that the current capacity usage and actual capacity provided by a real system investment does not unduly influence the overall signal. A change for spare capacity of scaling the signal down for historic commitments could be applied equally on a forward-looking basis when new capacity is provided in excess of that actually required i.e. the length should be increased to ensure the initiating User receives the full signal. A methodology that encompassed this feature could effectively be considered as a deep charging regime and would lose the smoothing element of the methodology.

No alternatives to the current regime were offered during the meeting. It was noted that the current methodology was discussed, consulted on and accepted during the GB process, therefore it was concluded that development in this area should not be pursued further.

7.5 Cost reflectivity of the expansion constant

National Grid opened the discussion as to whether the current methodology of calculating the incremental cost of capacity is perceived as cost reflective by identifying a range of elements that could be incorporated in a different manner. This discussion also covered the previously discussed issue of dis-aggregating elements of the model.

The incremental cost of capacity is currently calculated using National Grid's regulated cost of capital for capital expenditure of 6.25%. It was noted that the Scottish TOs currently have different allowable rates of 8.7% and 8.9% and it was considered whether these figures should be incorporated into the calculation. The initial assumption that the inclusion of the Scottish TOs' allowable rate of return would automatically increase the incremental cost of capacity across Great Britain was questionable considering the fact that the allowable rates of return are calculated on a pre-tax basis to allow for the individual financial circumstances of each TO or National Grid.

It was discussed whether it might be appropriate to calculate a regional incremental cost of capacity if the regional variation was sufficient and what the impact of this might be. The general industry response at CISG was that a regional variation might not be appropriate due to inconsistency with the overall methodology being GB and the fact that the cost of capital element is only a proxy for the Weighted Average Cost of Capital. Using the regulated cost of capital would not necessarily reflect the regional costs more accurately, introducing other historical elements.

When further considering the elements that should, or should not be included in the calculation, National Grid noted that interest during construction, engineering charges, associated equipment, under-grounding and telecoms are not included in the calculation as these are not kilometre-based. Rather than discussing those elements that should or should not justifiably form part of the calculation, the industry attendees noted their uncertainty over the materiality of including these components and asked that National Grid undertake further studies to illustrate this materiality.

National Grid identified the various techniques that can be used for increasing capacity, namely re-profiling, re-conductoring and the investment in quad boosters and reactive compensation equipment. The Ofgem representative noted that the establishment of the charging condition was driven in a large part by the desire for further technical assessment in this area.

The industry attendees suggested it might be necessary to determine the materiality of the various options available prior to making any decisions. National Grid noted that this would be reasonable, but that it was more a case of determining what is the right thing to do regardless of the materiality and that assessing the materiality first should not be the driver for the decisions that are to be taken.

8 Progress and further thoughts

This section reviews all the discussions to date. In addition it also indicates areas where National Grid will focus on in making improvements for implementation from April 2007.

The main issue that has come out of the industry discussions is not that the method used by National Grid is necessarily wrong, but it is not understood. In addition, it was not clear that the current calculation is fully representative of the GB position.

In order to address this first issue National Grid held a second workshop. In addition, National Grid also held an industry tutorial to raise the general level of understanding of the methodology. The feedback from the first of these has been extremely positive.

On the second issue National Grid is intending to ensure that the 2007/8 incremental cost of capacity is representative of GB costs. In order to do this National Grid will request data under the SO-TO code procedures. This will then be compared with England & Wales costs to ensure the final figure is comparable. In areas where there are differences this would be incorporated with the expansions factors that already exist. This is already covered within the methodology.

8.1 Transparency

At the first workshop Users indicated that they would like improved visibility of the data used to calculate incremental cost of capacity. Additionally they would like to see a worked example showing how the expansion constant of £9.81/MWh is derived.

The current methodology is based around an internal document called TR3. This provides forward-looking asset costs based on industry indices and recent schemes. National Grid considers these forecast costs to be commercially confidential.

Following further discussions at the second workshop and at CISG, it was clarified that Users accepted that some of the data used by National Grid was clearly confidential and could not be released. However, Users indicated that it was important to understand the process and high level assumptions National Grid adopts to calculate the incremental cost of capacity. This would allow Users to understand what was included in the locational element of the tariff.

At the second workshop National Grid provided a high level overview of the process used to calculate the incremental cost of capacity and presented a worked example to improve understanding.

Following on from discussion at previous CISG meetings, at the January 2006 CISG meeting National Grid also presented some high level alternatives that it was thought might improve transparency. These were:

8.1.1 Licence term, Gt.

National Grid's transmission licence contains a term called Gt. This is calculated during the price control and is used to adjust revenues if significant quantities of generation plant connect. Being publicly available, National Grid considered if it could be used as a proxy for the cost of incremental capacity.

However this term is linked to actual generation size (TEC) rather than system capacity provided and there is no similar term for Scottish Transmission Owners. In addition only the final figure is published. Therefore this figure is not consistent with the current methodology and would suffer from similar, if not greater, transparency issues.

Therefore National Grid does not believe it would provide any benefit over the current methodology, indeed considering it is derived for a different purpose would be a less cost reflective than the current method.

8.1.2 Recent historic costs

National Grid also presented an alternative that involved calculating the incremental cost of capacity on actual costs incurred over a limited number of previous years i.e. scheme costs. For example, if 1000 MWkm of capacity had been provided over the previous 3 years the incremental cost of capacity would be the average cost of providing that capacity on a £/MWkm base. The cost would be built up from actual developments that resulted in an increased capacity on the transmission system. This is not completely different from the current TR3 methodology, but would be focused on recent historical costs and include the whole scheme costs to provide the capacity rather than just the locational elements.

However, when this was discussed at the CISG meeting it was felt that if the costs were drawn from a shorter period and very scheme specific, then tariffs would become dominated by the cost of recent large projects. The reverse would also be true where for one particular category of plant only a small increment had been delivered over the period the sample would be too small to provide a reasonable basis for deriving incremental costs of capacity. As a result of this small sample issue and where no additional plant had been provided in the period covered, a methodology similar to TR3 that included tender costs and incremental historical costs on indices would still be required. On certain large projects there may also be transparency issues where only one project was used to derive the cost.

At the January CISG meeting attendees agreed that of the options provided, the current methodology that generally uses costs from a 10 year period struck an appropriate balance between stability and cost reflectivity.

On the general issue of transparency, Users agreed that improvements can be delivered through inclusion of the principles used to calculate the incremental cost of capacity in the methodology statement.

To take forward the issue of transparency National Grid will draft a more detailed explanation of the process followed and assumptions made when calculating the incremental cost of capacity. This improved drafting will be discussed at future CISG meeting to ensure it provides the information that Users require. Following this, National Grid will seek to include the drafting in the methodology statement. Inclusion of this information in the methodology statement does not represent a change to the actual methodology, but an improvement in transparency i.e. such a change will not result in changes to the tariffs, as such National Grid will not carry out a formal consultation.

8.2 Forward looking vs. Historic costs

At the first workshop it was suggested that the balance between historical costs and expected future costs needed to be reviewed. It was agreed that the methodology in general needed to strike a balance between historic costs (deterministic – what cost did you cause?) and future cost (forecast – what cost will you cause?).

It was noted that at one extreme true cost reflectivity will lead to deep connection charging which is by nature historic and that these costs can only truly be determined at the time of connection. Throughout the development of the GB charging arrangements and previous to that the PLUGs arrangements, the issue of deep or shallow connection arrangements has been discussed. The current shallow arrangements have been accepted as a fundamental principle within the methodology. Therefore National Grid does not support a TNUoS methodology based on fully specific costs and so does not intend to take this further as part of condition 2.

However, National Grid does acknowledge that the calculation of incremental cost of capacity could be based on historic or predicted future costs making it more or less forward looking. Therefore as part of condition 2 we have considered the following areas:

- The basic calculation for Incremental cost of capacity based on historic or forecast cost of assets
- Within the charging model, the question of what investments are included
- Limiting the use of historic data

Through the transport model the current methodology calculates an incremental or forward looking indicator (marginal km). This is calculated on the planned network for the year in question (year ahead at time of producing the tariffs), with the data taken from the seven year statement. The current incremental cost of capacity is based on adjusted historical costs that are the costs National Grid has recently experienced either through actual construction or tender returns. This provides the best forecast at any time for developments in the near future. Indeed, this same forecast is used as a basis for internal scheme costing. Where there is limited data available these costs will be adjusted by taking account of a wide range of indices such as the cost of materials (steel, copper etc), inflation or labour costs where these are a significant factor.

The marginal km calculated on the year ahead network model multiplied by incremental cost of capacity calculated to be as forward looking as possible provides, in National Grid's view, the best forecast cost for a development in the following year, and indeed most practicable solution for future years. If incremental cost of capacity was based exclusively on historic costs this would result in a less cost reflective signal for future investments.

This approach of using the best the forecast of likely costs based on the expected network for the year in question strikes a balance between cost reflectivity and facilitating competition. New Users and existing Users cause different costs on the network at the time of connection. However, a methodology that treats new and existing Users differently, based on historic costs incurred, could be viewed discriminatory and not in the best interests of competition. A basic principle of the methodology is that both new and existing Users, who can both make decisions that impact on future transmission investment, are exposed to the best available forward looking signal.

8.3 Future looking network model

From discussion, the most obvious way to develop a more forward-looking locational signal would be to use a transport model that takes account of developments beyond year ahead. It has been suggested National Grid could consider a Transcost type approach on the basis that it is more forward-looking.

In summary, the Transcost methodology calculates tariffs based on marginal costs for 10 separate years. The model calculates the required system investment and then calculates a node to node investment matrix for each year. The node to node matrices are then combined to provide individual nodal average marginal costs. The year-ahead tariffs are then produced through weighting the costs associated with the following 10 years from the combined cost matrix.

Adopting a similar approach of basing tariffs on predicted investments beyond one year ahead could be considered for electricity. Based on the forecasts from the condition 5 report, this would result in a step change in overall tariffs (because of a general year on year increase in differentials). This approach may make the tariff more forward looking in terms of forecast investment. However, the quality or accuracy of the improved signal is very dependant on the accuracy of the forecast of investments. Under certain scenarios tariffs may not be significantly more cost reflective, when the predicted investment does not go ahead. The adoption of such a methodology would be at the expense of a significant increase in complexity and loss of transparency. The amount of data used in a five year scenario would be nearly five times as much.

As mentioned above the current electricity tariff is calculated based on the year-ahead data from the SYS. This provides a high degree of certainty that any developments included have already started or are very likely to be completed in that year. The methodology could take account of future reinforcement in the SYS, however experience dictates that some of the SYS developments will not take place.

The Condition 5 report has sought to provide indications of how tariffs may develop in the future. This is based on forecast demand and generation scenarios along with expected investments. National Grid has suggested the accuracy of Condition 5 analysis should be monitored over a period of time. If a reasonable correlation can be drawn between condition 5 indicators and the actual tariffs and the data used to calculate the tariffs (forecast demand, connected generation and network model) then more fundamental changes to the methodology might be considered.

To do this National Grid has proposed that future condition 5 reports include a section reviewing the accuracy of previous reports against current tariffs. This approach was discussed with the industry through CISG and also presented at the TCMF.

In terms of the data used from the TR3 reports there was no indication from Users that this could be more forward looking. In discussion on whether the costs used should be more historic looking, the general consensus at CISG was that the current approach, whilst not perfect, was the best option available and attendees generally agreed. National Grid believes an incremental cost of capacity based on historic costs would be less cost reflective than the current approach described earlier.

8.4 Thermal ratings

The current methodology for calculating incremental cost of capacity assumes a unity power factor, mainly for reasons of simplicity. The cost of incremental capacity is calculated on an MVA basis i.e. the unit cost is £/MVAkm. However, the transport model derives marginal km based on one MW i.e. per MWkm. The simple example below seeks to demonstrate this concept.

Imagine a simple system with one generator connected to the rest of the system by an infrastructure spur. The Generator is 500MW, the spur is 10km long and costs £10m (per annum) to build. The actual capacity of the spur provided would need to be 500MW at 0.85 lagging power factor i.e. 583MVA.

The incremental cost of capacity in this example would be approximately £1715/MVAkm (ignoring the weighting with other developments for the purposes of showing cost reflectivity). When the tariff is then calculated from the assumed charging base, in this case a TEC of 500MW, the marginal km derived from the transport model for this section of the network would be 10MWkm (1MW over 10km of line). If the actual charges are also calculated on TEC this would results in slightly less recovery than £10m, (i.e. £8.5m).

This example is very simple and only intended to demonstrate the impact of calculating incremental capacity on MVA rather than MW. If the denominator in the incremental cost of capacity calculation was MW then the cost recovered would match the cost incurred. This example clearly ignores a number of significant effects such as zonal grouping, the G/D split and weighting.

A number of other options have been considered to deal with this issue. These were all discussed at the January CISG meeting. These essentially seek to either convert the current MVA based incremental cost of capacity to a MW incremental cost of capacity or adjust the tariff mechanism from a MW based system to an MVA system. The options considered are:

1. Calculate incremental measure on an MVA basis (MVAkm),
2. Calculate a cost of incremental capacity on a MW basis,
3. Use scaled TEC to represent MVA in the tariff model.

Both options 2 and 3 are methods which attempt to reflect the system power factor. They are both simplifications on AC modelling however they still add complexity and more subjective judgement to the existing calculation for an arguable increase in cost reflectivity.

8.4.1 Calculate incremental measure on an MVA basis (MVAkm)

Calculating marginal km on an MVA basis would require an AC transport model, increasing the complexity by an order of magnitude. An AC model would also significantly reduce the transparency, stability and predictability due to increased subjective nature of AC load flow analysis and the increased data requirements e.g. voltage profile. This would make it extremely difficult for someone not extremely familiar with electricity system modelling to pick up the model and produce tariffs. Indeed for only minor adjustments in any of the input variables it is unlikely that even a skilled user could not replicate the results exactly.

This was discussed at the January CISG meeting in some detail and the general agreement was that the current DC based methodology was a reasonable simplification and that the marginal increase in accuracy provided by an AC model would be far outweighed by the loss of transparency, predictability and simplicity. Given these discussions National Grid does not propose to take forward the development of an AC model as part of condition 2.

However, National Grid is aware of developments in the distribution charging arena where the use of AC models is being considered. National Grid will continue to monitor these and where true benefits can be delivered without undermining other areas National Grid will consider separate developments. We note that application of an AC model to a mainly passive radial network that is connected to an infinite bus is much simpler than to a fully active system required to be self supporting (the transmission system).

8.4.2 Calculate a cost of incremental capacity on a MW basis

If the cost of incremental capacity is calculated on a MW basis, the unit cost would increase (assuming a system power factor of less than 1). The size of the increase would be proportional to the assumed power factor. The current methodology assumes a unity load factor so the MVA and MW figures are interchangeable within the methodology.

The selection of power factor would be very subjective, there is not one system power factor as it varies on every circuit and along every circuit. In the generation spur example above it is presented simply but in practice, even in such a simple connection, the MVA at the end of the spur will be a combination of the output from the generator and the reactive power created (positive or negative) by the transmission system (including spur circuits). In general, reactive power is not transported across the system. The reactive power on a single line will be different at both ends unless it is perfectly balanced at its ‘natural load’. The natural load is related to the physical parameters of the line.

Following discussions at CISG and given the hugely subjective nature of deciding what power factor should be assumed National Grid are not proposing to take this forward. However, at CISG National Grid agreed to provide an example of tariffs based on this. Attached as Appendix A are the indicative tariffs for 2006/07 with a system power factor of approximately 0.975 assumed in the calculation of incremental cost of capacity. This figure is hugely subjective and would be extremely difficult to justify.

8.4.3 Use scaled TEC to represent MVA in the tariff model.

This option considers if charges could be based on MVA rather than a MW. A 100 MW unit could be charged for its TEC adjusted for mandatory / commercial reactive output i.e. 120 MVA (and demand for MVA taken). Similarly, demand could be charged on MVA predicted or MW adjusted by a specific or standard power factor. In effect this would increase the charging base. In terms of generation, noting referencing maintains the 27% spilt of recovery, this would increase the locational element of recovery i.e. generators in the north would pay more and generators in the south would receive more. In terms of demand the power factor for design is based on Grid Code submissions at a nodal level. There is no clear standard for demand power factors. An average factor for GB, or zonal could be established. Although this would probably be done through factors applied to a single incremental cost of capacity the effect would be to have a different incremental cost of capacity for demand and generation.

This option would represent a fundamental change to the charging arrangements as the actual charges would then need to be levied on an MVA basis to be consistent with the tariff, moving away from TEC. In terms of incentivising more efficient behaviour by users for investment in reactive compensation, adjusting the indirect options discussed above are unlikely to achieve this. Appendix B provides indicative tariffs based on a potential generation factor of 1.16 (1/0.85) and demand factor of 1.05 (1/0.95). The selection of these factors is very subjective, peak grid code capacity for generation and average peak demand.

In considering these ‘refinements’ National Grid need to consider the context in which they are being applied. The output of the DC load flow may be considered as not sufficiently accurate enough to meaningfully apply options 2 and 3 above in a robust and defendable manner i.e. to be able to reasonably understand whether they are actually more or less cost reflective against a range of scenarios. In terms of wider infrastructure, the marginal km figure derived from the transport model can not reasonably be considered as a proxy for any individual User driven non-thermal investment. In order to establish a reasonably cost reflective proxy there would need to be a move towards an AC model. This issue is closely linked to later discussion on possible approaches to dealing with other transmission equipment such as reactive compensation.

Following lengthy discussion on this issue at CISG, National Grid are not proposing to take these developments further as the advantages are either clearly outweighed by the disadvantages (in the case of an AC model), or there is little evidence that they would provide a robust or justifiable solution.

8.5 Spare Capacity

At the first workshop the inclusion of spare capacity was questioned. During the BETTA consultation process it had been suggested that the incremental cost of capacity should be adjusted to take account of any spare capacity on the system.

This issue was further discussed at the second workshop and at CISG. The general response was that most users agreed that it was not appropriate to include spare capacity on an unconstrained and incremental methodology.

Within the methodology incremental cost of capacity represents the £/MVAkm cost of building a 400kV overhead line. The calculation is bottom up rather than top down, so it does not include any cost of spare capacity. Whether circuits are used to full capacity or not (or indeed exceed full capacity) will not change the MWkm figure derived from the transport model.

The transport model derives marginal km on a nodal basis. This is for an unconstrained simplified system i.e. on the base system 500MW will only cause 500MWkm travelling over 1 km of line. Whether the line is rated at 750MVA or 1500MVA, this will not change the base flows or the marginal km derived from the model. The proportion of the line that is not accounted for during the locational calculation is dealt with entirely separately through the residual element of the tariff.

The adjustment of incremental cost of capacity was discussed at length through the GB charging process, National Grid continue to believe that it would be inappropriate to adjust incremental cost of capacity, as suggested by some parties, or scale the data in the transport model to deal with spare capacity. National Grid believes such an approach would be less cost reflective.

The decision to remove spare capacity from the transport model was part of the final GB charging proposals and accepted by Ofgem. In the Authority's decision and the resulting conditions there was no reference to concerns about the removal of spare capacity.

It is also our understanding that the Authority's reasoning on this issue is that the spare capcity is over and above the buffer of capacity required to maintain network security and the model is a stylised model which seeks to reflect the long-run costs. Explicitly adjusting for spare capacity within incremental cost of capcity would result in charges which are more susceptible to short-run influences at the expense of a more stable and predictable signals. The accepted methodology as a whole results in individual users paying differentially only for the capacity they use, and not the capacity available in their vicinity.

This issue has been presented and discussed with the industry at the TCMF and CISG respectively. No further alternatives to the current methodology were suggested at these meetings and in general the majority of participants supported the current approach. Given the above points, and noting the discussions and views expressed throughout the GB changing methodology development process, National Grid does not intend to take forward any changes to the methodology concerning spare capacity as part of the condition 2 review process.

8.6 Cost reflectivity of expansion constant

National Grid agrees that techniques other than new build OHL need to be examined. This could include incorporating the cost of similar elements that increase capacity such as Quadrature Boosters and reactive compensation equipment. During industry meetings an analogy was drawn between providing capacity though such reinforcements and providing capacity by installing compressors in the gas methodology. National Grid has sought to break down the overall cost reflectivity of the expansion constant into the individual areas. Following this approach the areas National Grid has considered are:

- Inclusion of the cost of other techniques for increasing capacity:
  - Re-profiling of existing lines;
  - Re-conductoring of existing lines;
- Individual elements used in the calculation:
  - e.g. Cost of capital;
  - Upgrade factor;
  - Dis-aggregation;
- Inclusion of other plant delivering capacity:
  - Quadrature boosters;
  - Voltage compensation devices (SVCs, RSVCs, MSCs, reactors);

The section below covers each of these areas in turn.

8.6.1 Inclusion of the cost of other techniques for increasing capacity

8.6.1.1 Re-profiling of existing lines

Re-profiling of existing lines is a very economical way of providing additional capacity on a circuit. Although different for each circuit, it is estimated an average cost of re-profiling an existing circuit could be anywhere up to 20%

the cost of new build. Re-profiling involves surveying a line and where required, adjusting tension to ensure clearance is not infringed when the line is operated at a higher temperature. Depending on the actual project, it may be necessary to replace or heighten towers along a route (in deciding on this option we also need to consider the costs and risks of taking a double circuit outage). The ability to increase the rating is limited by the overall original design of the conductor and towers. In certain locations and on many circuits it may not always be possible, cost effective, or feasible to increase the rating through re-profiling.

The potential additional capacity gained is significantly lower than refurbishment or new build. Given the limited capacity provided by this method it is commonly used to provide flexibility for operational reasons i.e. manage short run costs. Although the cost appears relatively low on a route basis, this has to be measured against the actual incremental increase in capacity. The actual calculation of rating is based on a statistical analysis looking at the probability of infringing clearance. The final rating may also be limited by other factors such as the maximum temperature the grease within the line can withstand.

Within England and Wales re-profiling has been used where possible on circuits on constrained boundaries. Once a circuit has been re-profiled any further increase in capacity has to come from other techniques e.g. re-conductoring or new build. Therefore, going forward there is limited additional capacity that can be achieved through re-profiling. Within the forecast investment plan there is very minimal additional capacity provided by re-profiling. This technique may not have been previously employed in Scotland so limited additional capacity may be available on the Scottish system. However, the vast majority of capacity provided for new developments is generally in excess of that available through re-profiling. Our understanding is that works identified for the Renewable Energy Transmission Study (RETS) by licensees does not include any expectation of re-profiling providing any significant additional capacity.

Based on the forecast investment plan it appears that assuming 20% of capacity provided by re-profiling going forward to be quite high. In addition minor reconfigurations, such as adding bussing points to the network, re-tensioning of the bottom phase only or replacing the fittings to enable re-tensioning can also be used to provide additional capacity and have been included in the figures. Having further reviewed the data, up-rating that does not involve re-conductoring is also included in this category i.e. where a double circuit has been built at 400kV although one side has been run at a lower voltage. In these circumstances the upgrade cost of the line is more comparable to re-profiling than re-conductoring.

8.6.1.2 Re-conductoring of existing lines

Re-conductoring is another technique used to provide additional capacity. It can provide a significantly larger block of capacity per route compared to re-profiling, and so is more commonly used to provide capacity for new developments. On many route where re-profiling has first been considered, particularly older routes, following further engineering works re-conductoring is adopted as the overall economic solution.

From a planning perspective, the major advantage of re-conductoring is that it uses existing routes and has limited impact on towers. In some circumstances a number of towers will also need to be replaced along a route. From an environmental and consent perspective, re-conductoring has significant advantages over new build.

The actual cost of re-conductoring is more expensive on a £/MWkm capacity basis than new build. Inclusion of weighting for re-conductoring will therefore tend to increase the cost of providing capacity.

Based on generic figures the cost of re-conductoring is in the order of 40% more expensive than new build on a £/MWkm basis. These figures are based on historic actual developments and tenders. This range varies between 130% and 160% depending on the type of original and replacement conductors to be used.

Accepting that the weighting between the technologies can change, Table 4 below was used in the GB charging process to show how the costs can vary depending on the weighting between re-profiling, re-conductoring and new build.

Table 4 Technology weighting

		Weighting Scenario		
	Cost as a percentage of new build	1	2	3
Re-conductoring	140%	50%	40%	30%
Re-profiling	20%	20%	20%	20%
New build	100%	30%	40%	50%
Average		104%	100%	96%

Table 4 shows that although only a percentage of additional capacity will be provided by new build, for a reasonable range of scenarios the overall cost will be approximately that for new build. Depending on the assumptions made about how much capacity can be provided by each technique the average cost may be above or below that of new build.

We have further analysed the data and assumptions used in producing the original table. Given the discussions above on the potential variability (to cost and capacity provided) considered with each technique, we still understand these to be reasonable approximations of the costs.

National Grid has also checked the costs with a number of options for re-conductoring (types of original conductor). The figures for the potential new capacity from re-profiling appear large given the limited nature of this technique. However, the figures in table 4 include other lower cost options for providing capacity discussed above, such as up-rating where re-conductoring was not necessary. The relative cost of such reinforcement is significantly lower than re-conductoring and is more comparable with re-profiling.

When discussing possible ways of improving transparency National Grid highlighted a possible option that National Grid could take the sum cost of providing additional capacity by any method in any year and divide that by the overall increase in capacity in that year for those costs incurred. In the discussion on transparency National Grid noted that the period this covered would be a critical factor and in general National Grid believes this would make the calculation of incremental capacity more subjective and less transparent. Such a methodology would also make the cost of incremental capacity more historical looking.

Given the above issues and the more detailed analysis performed, National Grid continues to believe that the current methodology that assumes that the cost of new build can be taken as a reasonable proxy for the cost of new capacity is appropriate. When presented at CISG the general views expressed seem to support our conclusion. Therefore National Grid does not intend to take forward any changes to the methodology in this respect.

8.6.2 Individual elements that make up the expansion constants

Table 5 below highlights individual elements that make up the expansion constant. These have been discussed with the industry at the workshops and CISG meetings. Below we discuss the general and specific issues.

Table 5 Expansion factor elements

Element	Supplied / calculation	Purpose
Annuity factor	Combination of asset life and cost of capital, currently 0.066	Used to calculate the annual cost
Asset Life	Average asset life. The current calculation uses 50 years.	Used to calculate the annuity factor
Cost of capital, WACC	6.25%. Taken from cost of capital for National Grid's regulatory price control.	Used to calculate the annuity factor.
Overhead factor	1.8 %. Set based on historic internal data for E+W. Verified as representative for GB during GB charging process.	Represents allocation of the global overhead on an asset basis.
OHL / cable costs	Actual developments and tenders, adjusted by calculated indices.	Used to calculate the basic £/MVAkm for each type / voltage/ rating
km in last 10 years	Transmission asset database	Used to weight the type / rating of conductors to recently used types.
Upgrade factor	Projected investment plans and potential for upgrade.	Used to weight the expansion factors in transport to account that upgrading lower voltages will account for a percentage of required capacity.

In discussion with the industry at the workshops and CISG there appeared to be some concern that the figures used reflected the England and Wales data rather than GB data. It is true that in certain cases the approach was taken that the England and Wales data would be used, mainly as wider data was not available at the time, when the data became available it would be incorporated as required.

When Scottish transmission data was made available, in most cases, rather than completely recalculating the constants, a comparison of the source data was made. Where there was a reasonable correlation, which was generally true, rather than completely recalculating from the base data it was taken that the England and Wales figures were reasonably representative of the GB position and so could be used. Clearly, the individual expansion factors were derived on the actual regional data.

As discussed at the industry meetings on condition 2, National Grid will seek to ensure that in the future the cost of incremental capacity is drawn from the most representative data available, this includes sourcing information on transmission costs from the transmission owners. The STC provides for National Grid to request information to support the licence duties in respect of charging. This is already the practice carried out and implicit within the existing calculation of expansion factors.

8.6.2.1 Asset life

The asset life used in the annuity calculation is based on 50 years. This seeks to represent the true average life of the assets taken account of in the calculation (primarily the conductors and towers). National Grid will review this figure in producing the 2007/08 tariffs. This review process would have been carried out as part of the internal setting of incremental cost of capacity at the beginning of a price control period irrespective of condition 2.

8.6.2.2 Weighted Average Cost of Capital

The current incremental cost of capacity is derived using a cost of capital of 6.25%. At the time of this calculation it was assumed that using the regulatory rate of return (that is expected to reflect the efficient level of cost of capital) was a reasonable proxy for use in the annuity calculation.

Under the GB arrangements, 6.25% is not a common regulatory rate of return for all the transmission licensees. SPTL and SHETL have a regulatory cost of capital of 8.9% and 8.7% respectively in 2006/07, calculated from the post tax figures for the extension period.

Other than solely using National Grid's cost of capital, the two alternatives discussed at CISG were to use zonal costs of capital or to use a weighted GB average. The weighting would be based on the total GAV of the GB TOs. At the meeting the general view was that although there would be some logic for zonal application, suggesting it could be more cost reflective, that over-reliance on the regulated cost of capital in this area would be inappropriate.

Based on the discussion, a single weighted GB average appears to be the most appropriate figure to use in the annuity calculation. National Grid has not provided detailed indicative figures as the figures that would be used are not available and National Grid do not believe 6.25% set 5 years ago and the calculated pre tax figures of 8.9% and 8.7% set more recently are directly comparable.

A weighted average based on GAV of infrastructure assets on the above figures would be 6.81%. To illustrate the effect of this, a 0.5% increase, i.e. 6.25% to 6.75% carries through to an increase in the annuity factor from 0.066 to 0.07. This would make an expansion constant that was £9.506/MWkm become £9.958/MWkm. Such a change would increase the overall locational differentials in the DCLF transport model.

Given the industry discussion at the CISG it would appear that over reliance on the differences in regulated cost of capital would not be appropriate. The regulated figure includes many factors that may not be appropriate within an incremental cost of capacity that seeks to be forward looking. Historically the regulated cost of capacity has been used a reasonable figure but there could be a number of other mechanisms for establishing a representative WACC.

Given this National Grid propose to continue to use regulated cost capital in National Grid's price control in the calculation.

8.6.3 Inclusion of other plant delivering capacity

8.6.3.1 Inclusion of Quadrature Boosters

In discussion at the workshops and CISG it was suggested that the incremental cost of capacity or the methodology in general should take account of Quadrature Boosters (QBs). This was also mentioned during the GB charging process.

QBs themselves do not actually increase the capacity of a line, rather they redistribute power flows across a boundary to increase the overall boundary capability. The benefits that lead to installing QBs are not entirely based on the £/MW capacity, but are significantly influenced by consents, environmental factors and providing flexibility for managing operational costs.

Within a constrained system QBs are generally used to 'buck' flows, this is to restrict flow on the line the unit is installed in, and in most instances the buck mode will only be fully required post-fault. A QB consists of two elements; a series unit and a shunt unit. The series unit capacity is chosen to align with the circuit it is placed in series with. The shunt unit, which is a much lower rating, injects a quadrature voltage into the main unit to adjust the phase angle and hence adjust the power flow on the line.

The additional capacity provided is not linked to the series capacity but the increased capacity on the boundary that it has been installed on. An approximate figure for the increased boundary capacity would be in the region of 50% of the series unit. This figure is of course very subjective and depends on the configuration of the system as a whole.

The cost of a QB is not distance related in the same sense as an OHL. There is no direct £/MWkm that can be attributed to a QB. National Grid has looked at a few different methods of allocating the costs in a different manner, these are discussed below.

On each individual boundary one can asses the overall capacity increase and attribute the cost of the QB to the lines across the boundary, increasing the £/MWkm for all the circuits on the boundary. In order to show the relative cost one can assess the cost of the QB in terms of £/MW and compare that to the cost of increasing the thermal capacity by installing an equivalent line, as shown below.

For example, for a pair of QBs on a 2000MW double circuit costing £1m per annum, the relative increase it would give on a boundary is only likely to be in the order of 50% of the individual unit rating i.e. a 1000MW boundary increase. This delivers an annual cost in the order of £1000/MW. If the boundary length was 100km (average length of circuits across the boundary) an equivalent cost based on an expansion constant would be in the order 10 £/km. Clearly within this calculation there are a number of development-specific and subjective assumptions, however the overall cost of capacity in this example is reasonably equivalent to the current incremental cost of capacity.

This calculation can be performed in a number of other ways, for instance sharing the increase in capacity across all circuits, leaving the cost of the QBs with the circuits they are in series with and allowing the cost to feed though the average weighting described earlier. Reviewing a number of methods of including the costs and some of the major developments already undertaken, on average National Grid would expect inclusion of a proxy value for QB to slightly increase the overall expansion constant, however the increase would not be significant.

It is also important to consider the system model in which the QBs are being used, the normal settings for a QB on peak and the effect it has on 'marginal' flows. Current QBs are modelled as series reactors i.e. on nominal tap. The transport model is an unconstrained model, i.e. the rating of circuits is not considered. In addition, all nodes are modelled as solid. In practice, for a number of operational reasons, the normal operational mode on system peak is to have the QBs fairly close to nominal tap. The QBs are generally tapped post-fault to 're-secure' the system. These issues combined would suggest there is little or no benefit in adding dynamic QBs into the transport model as they will have minimal affect on the unconstrained flows.

However, the QBs effect could be added by increasing (or decreasing) the series impedance. This would, in the case where QBs are used to restrict flows, stretch the differentials i.e. increase the marginal km for nodes in the north and increase the negativity for those in the south. Combined with the higher expansion constant this would result in increased positive generation charges in the north and increased negative demand charges for generators in the south (the reverse would be true for demand).

Noting the issue about the operational mode i.e. that QBs are used to re-secure the system, and that in practice they are only used at extreme taps during specific outages or post-fault, then it would appear more logical that they are accounted for through the residual element of the charge. This approach is also consistent with their role in providing operational flexibility. It also avoids any potential for double accounting with the security factor.

At the CISG meeting National Grid also discussed the possibility of introducing a third type of zonal element related to these assets (and reactive compensation) beyond the existing locational and residual charges. The zones would be based on system constraint boundaries where QBs and reactive compensation had been installed to increase capacity. The cost recovered from this would be removed from the residual element of the tariff. The general response was that this was overly complex and hugely subjective. The selection of zones would not be stable and could not easily be determined by a clear rule based system, but by the interpretation of system studies.

Having considered the overall subjectivity of including QBs within the model and the fact that the effect in the simplified transport model would not accurately reflect the benefits of the QB, National Grid are proposing the suggested implied increased cost reflectivity of inclusion of QBs in the transport model and within the expansion factor calculation are outweighed by the increased subjectivity and complexity that this would introduce. Indeed the increased cost reflectivity can not been robustly demonstrated.

8.6.3.2 Inclusion of voltage compensation devices (SVCs, RSVCs, MSCs, reactors)

Reactive power is generated or absorbed in transmission equipment and by end Users of the transmission system. Voltage compensation devices support higher boundary flows or ensure that User demand for reactive power is met at a particular location. Overall reactive compensation ensures that power is delivered or transported in a stable manner within the limits prescribed in the SQSS. Reactive compensation is generally located where reactive power from a Power Station is not available or cannot be relied upon and reactive power can not be taken to ‘flow’ around the system.

There are essentially two types of compensation, static and dynamic. Static compensation can be considered as capacitors or reactors. Although some of these can respond in a limited dynamic manner by the use of automatic switching of circuit breakers. Dynamic compensation is compensation that can respond is very short timescales, generally in a smooth manner, rather than switching via a circuit breaker where power electronics are used.

The normal operational practice is to use static compensation to set up and maintain an acceptable voltage profile for forecast conditions. Separately, sufficient dynamic compensation is kept available to respond to short term voltage variation or faults on the system (which can cause a sudden non-linear increase in system demand for reactive power due to the increased loading of the remaining lines).

In order to avoid voltage collapse that can occur when reactive power supply becomes exhausted, this normally requires that SVCs are operated at float (zero output). SVCs also have an added benefit of being able improve the stability of the system. Overall static compensation is normally considered as 'committed', whilst dynamic compensation provides 'reserve'.

At different locations on the system the need for reactive power compensation may be driven by local end User power factors or by the need to transport large power flows through an area. The requirement is not directly linked to distance, although distance is a factor in determining the overall reactive power demand. Another, more important factor is the actual loading and characteristics of the transmission system. For example, a long line at a quarter of its rating will have virtually no need for reactive power whereas a short line at near maximum load will create a significant demand, which becomes more significant with length.

The need for reactive power equipment in planning timescales is determined through secured voltage and stability studies. A DC load flow cannot be used to forecast the need for reactive power and modelling of a voltage compensation device would have no effect on the actual power flows in the model. Whilst it may be possible to produce a proxy associated with line loading that could indicate the need for reactive compensation, within the current transport model it is not feasible. To try and achieve this, the transport model would need to be set up as the actual system on each peak. This would make the transport model far more complex, less stable and less transparent.

Compensation assets are accounted for under the residual element of the tariff. National Grid considers this a reasonable simplification given the assets are largely associated with the overall quality of the supply that all Users benefit from.

National Grid does not believe the benefits of developing a much more complex model and charging base to incorporate reactive power demand outweighs the benefits of transparency and simplicity of the current model and methodology.

However, National Grid does recognise that there are issues around power factor correction and providing the correct incentive through the charging mechanism. As this is not directly linked to the cost of incremental capacity, and mainly driven by DNO investment rather than suppliers or generators, National Grid does not propose to take this issue forward as part of this particular review.

9 Next Steps

Following the receipt of views on the issues covered in this report, National Grid will consider these and inform the June TCMF of its conclusions. National Grid will also indicate at that time the areas of the methodology it proposes to change and so consult on over the summer.

Appendix A

Indicative final tariffs based on 2006/7 data with the incremental cost of capacity based on a 0.975 system power factor.

Derivation of Zonal Demand HH Tariffs				
Zone	Zone Name	Final Tariff (£/kW)	New Final Tariff (£/kW)	Difference (£/kW)
1	Northern Scotland	0.445	0.080	-0.366
2	Southern Scotland	5.437	5.200	-0.238
3	Northern	8.441	8.280	-0.161
4	North West	11.974	11.904	-0.070
5	Yorkshire	11.995	11.925	-0.069
6	N Wales & Mersey	12.218	12.155	-0.064
7	East Midlands	14.511	14.506	-0.005
8	Midlands	16.052	16.086	0.035
9	Eastern	15.089	15.099	0.010
10	South Wales	19.717	19.846	0.129
11	South East	17.897	17.978	0.082
12	London	19.730	19.859	0.129
13	Southern	19.379	19.499	0.120
14	South Western	22.170	22.362	0.191

Derivation of Zonal Generation Tariffs				
Zone	Zone Name	Final Tariff (£/kW)	New Final Tariff (£/kW)	Difference (£/kW)
1	Peterhead	18.394	18.758	0.364
2	North Scotland	20.519	20.938	0.418
3	Skye	N/A	N/A	N/A
4	Western Highland	18.621	18.991	0.370
5	Central Highlands	15.413	15.700	0.287
6	Cruachan	N/A	N/A	N/A
7	Argyle	13.521	13.760	0.239
8	Stirlingshire	13.065	13.293	0.227
9	South Scotland	12.141	12.344	0.204
10	North East England	8.885	9.006	0.120
11	Humber, Lancashire & SW Scotland	5.614	5.650	0.036
12	Anglesey	6.284	6.337	0.053
13	Dinorwig	8.939	9.060	0.121
14	South Yorks & North Wales	3.836	3.826	-0.009
15	Midlands & South East	1.219	1.143	-0.076
16	Central London	-5.495	-5.744	-0.249
17	North London	0.362	0.264	-0.098
18	Oxon & South Coast	-0.514	-0.635	-0.121
19	South Wales & Gloucester	-2.737	-2.915	-0.178
20	Wessex	-5.065	-5.303	-0.238
21	Peninsula	-9.146	-9.488	-0.342

Basing the incremental cost of capacity on a system power factor of 0.975 results in an increase in the 2006/7 incremental cost of capacity of 10.069 to 10.327 (an increase of 2.56%). This serves to proportionately ‘stretch’ the locational element of the tariffs for both demand and generation by 2.56%, whilst the residual element of tariffs remain the same.

Appendix B

Appendix B provides indicative final tariffs based on a potential generation factor of 1.16 (1/0.85) and demand power factor of 1.05 (1/0.95).

Derivation of Zonal Demand HH Tariffs

Zone	Zone Name	Final Tariff (£/kW)	New Final Tariff (£/kW)	Difference (£/kW)
1	Northern Scotland	0.445	-0.290	-0.735
2	Southern Scotland	5.437	4.702	-0.735
3	Northern	8.441	7.706	-0.735
4	North West	11.974	11.239	-0.735
5	Yorkshire	11.995	11.260	-0.735
6	N Wales & Mersey	12.218	11.483	-0.735
7	East Midlands	14.511	13.776	-0.735
8	Midlands	16.052	15.316	-0.735
9	Eastern	15.089	14.354	-0.735
10	South Wales	19.717	18.982	-0.735
11	South East	17.897	17.161	-0.735
12	London	19.730	18.995	-0.735
13	Southern	19.379	18.644	-0.735
14	South Western	22.170	21.435	-0.735

Derivation of Zonal Generation Tariffs

Zone	Zone Name	Final Tariff (£/kW)	New Final Tariff (£/kW)	Difference (£/kW)
1	Peterhead	18.394	17.764	-0.630
2	North Scotland	20.519	19.889	-0.630
3	Skye	N/A	N/A	N/A
4	Western Highland	18.621	17.991	-0.630
5	Central Highlands	15.413	14.782	-0.630
6	Cruachan	N/A	N/A	N/A
7	Argyle	13.521	12.891	-0.630
8	Stirlingshire	13.065	12.435	-0.630
9	South Scotland	12.141	11.511	-0.630
10	North East England	8.885	8.255	-0.630
11	Humber, Lancashire & SW Scotland	5.614	4.984	-0.630
12	Anglesey	6.284	5.653	-0.630
13	Dinorwig	8.939	8.308	-0.630
14	South Yorks & North Wales	3.836	3.205	-0.630
15	Midlands & South East	1.219	0.589	-0.630
16	Central London	-5.495	-6.125	-0.630
17	North London	0.362	-0.268	-0.630
18	Oxon & South Coast	-0.514	-1.144	-0.630
19	South Wales & Gloucester	-2.737	-3.367	-0.630
20	Wessex	-5.065	-5.695	-0.630
21	Peninsula	-9.146	-9.776	-0.630

The impact on the nodal marginal km is zero as generation is scaled to meet demand. The increase in the generation charging base (1/0.85) by a greater factor than the increase in the demand charging base (1/0.95) reduces the locational element of the generation tariff uniformly by -£0.055/kW at the expense of the locational demand tariff which increases by £0.055/kW.

The increase in the charging base also serves to reduce the residual element of the demand tariffs by £0.789/kW from £12.425/kW to £11.636/kW, whilst the residual element of the generation tariffs reduces by £0.575 from £3.550/kW to £2.975/kW.