Report from the Transmission Access Standing Group

August 2002

7th August 2002

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1.0 Introduction

On 26th February 2002 Ofgem published "Transmission Access and Losses under NETA: revised proposals". This report invited the industry to consider the proposals further under the governance of the CUSC (in respect of Transmission Access).

In response to this suggestion the CUSC Panel considered the matter at its meeting on 22nd March 2002 and agreed to establish a Standing Group to identify and evaluate options for change (the full Terms of Reference for the Standing Group are reproduced in Appendix 1).

Although the formalities of the CUSC required the Panel to nominate an initial list of Members of the Standing Group (as contained in the Terms of Reference), in practice the membership of the Group and contribution to the discussions was drawn from a wider membership of the Industry as indicated by the attendance at the various meetings (the attendees and minutes of the TASG meetings can be found on NGCs website).

2.0 The Work of the Standing Group

The Standing Group met 7 times between April and July 2002.

The first meeting (25th April 2002) of the group was solely concerned with agreeing a refined Terms of Reference for submission to, and subsequent approval from, the Panel together with agreeing an expanded membership of the Group.

The second meeting (9th May 2002) heard presentations on the current Transmission Access regime together with a view of the pertinent features contained in the February 2002 Ofgem document. It then went on to agree that future discussions should be centred around 5 key questions being answered from the perspective of different categories of market participant.

The third meeting (22nd May 2002) heard these presentations and facilitated discussion as to the extent to which the ideas contained therein met the objectives as set out in the Ofgem document and the advantages and disadvantages that would accrue to participants if such proposals were to be implemented.

The fourth meeting (10th June 2002) heard a presentation on European developments in the area of Transmission Access and debated the extent to which these could be considered to constrain the development of options in the UK. In addition NGC presented a "strawman" based on the discussion and presentations from the third meeting. The stated intent of this proposal was to be an evolution from the current arrangements rather than a radical departure from them. This "strawman" was further refined following subsequent debate, particularly in respect of the demand side of the market as the original version concentrated on the generation side.

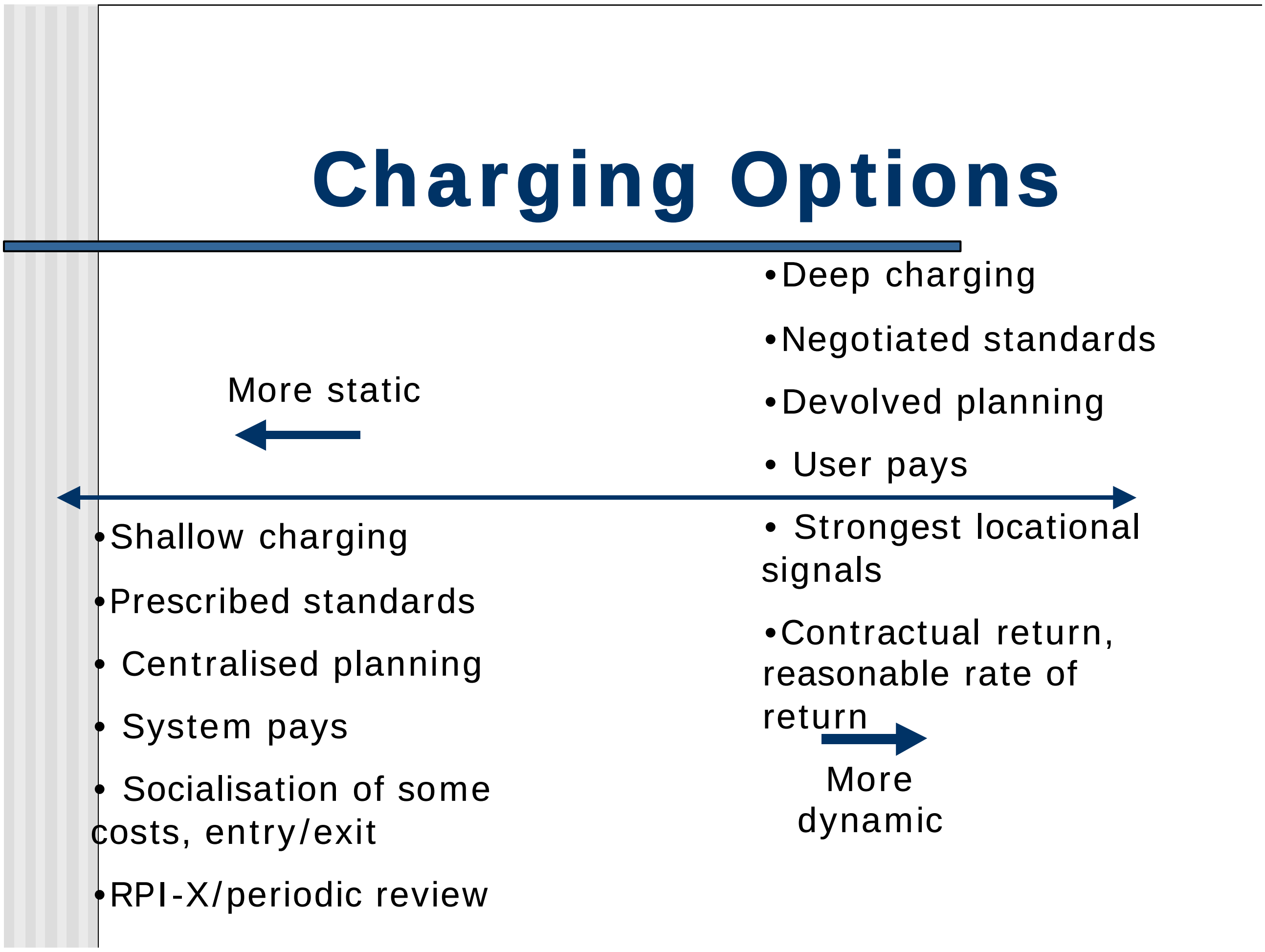
The fifth meeting (21st June 2002) concentrated on refining the strawman proposals and, in particular, the implications of Users purchasing rights for periods greater than 1 year at defined prices.

The sixth meeting (5th July 2002) reviewed the discussions to date on the Generation / Entry side of the market and further developed proposals for the Demand / Exit side of the market.

The seventh meeting (23rd July 2002) of the Standing Group considered and amended the draft report prior to its submission to the August 2002 CUSC Panel.

3.0 The Driver for Changes to the Contractual Framework

Changes to the current Transmission Access regime are a corollary of Ofgem's desire to establish a system of rights to use the system and thereby improve NGC's investment signals and incentives. In order to achieve this Ofgem believe that it is necessary for access rights to be purchased on a long term basis (in contrast to the current arrangements) and for those rights to be "financially firm". On the generation side, to a large extent this is the current position. This is characterised as "more dynamic" in the diagram below.



The Group discussed the implications of moving from the current regime (characterised as "more static") for NGC's security standard and the current method of shallow connection charging. On the first issue it was noted that the last time the security standard was reviewed, following a lengthy debate, the majority of Users had accepted that the current standard was appropriate. In the "more dynamic" scenario NGC's investment decisions would concentrate on whether the NPV of the constraint costs exceeded the NPV of the investment cost, rather than being driven by a defined standard.

On the second issue there was an instinctive feeling amongst the Group that the current shallow connection charging methodology would not be theoretically compatible with maximising economic efficiency as the cost consequences of one party's actions are shared with other users and blurs the incentives. However, the Group recognised that Ofgem's stated position was that it is not in favour of deep connection charging and elected not to discuss this option further.

Although the Standing Group was formed under CUSC governance which is concerned with the contractual arrangements, the subject matter of the discussion inevitably took the Group into the province of Charging Methodologies and other areas outside the direct remit of CUSC. The Group recognised that where it has discussed such matters it was in order to explore options and implications rather than making recommendations.

4.0 Consideration of Transmission Access Schemes

In order to focus discussion it was agreed to use the following 5 questions:

1. What is the definition of the rights, obligations and charges ?
2. Who buys, sells and trades the access rights or obligations ?
3. What are the consequences for breaching the rights ?
4. What are the contractual relationships between the parties ?
5. What are the implications for NGC's investment decisions and Price Control ?

The different options or cases that were developed by the Standing Group arose from the different options for the "charging" element in Question 1 which, in turn, determined the response to Question 5. This applied equally to the Generation / Entry side of the market as well as the Demand / Exit side of the market.

Questions 2 and 4 are related and gave rise to different proposals for the Demand / Exit side in comparison with the Generation / Entry Side whilst applying the same principles in respect of the other questions.

4.1 Generation / Entry

Definition: The right to export up to a nominated level (expressed in MW or MWh) at the Boundary Point, in any half hour. This would be the Maximum Export Capacity (MEC). This would be capped at the relevant Connection Capacity. There would be no obligations to generate at defined levels at defined times (but there may be charging implications, particularly if the right is associated with a negative charge – i.e payments would only be received if generation ocurred at defined times).

The right would apply to a specific Entry Point.

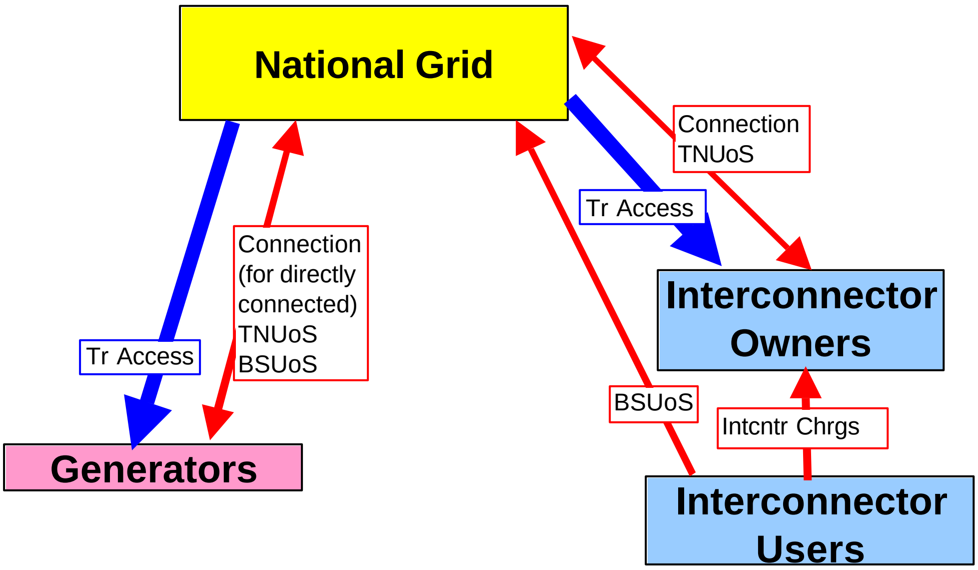
Participants: In respect of the initial allocation it would effectively be mandatory for Licensed Generators – either Directly Connected or Embedded Generating Stations – and Interconnector Owners. Exempt generators could elect to participate if they so choose (the option of Licensed Embedded Generators contracting with the Distribution Business to which they are connected exists, but was not explicitly discussed by the Group).

Contracts: The Access Rights would be firm and NGC may choose to enter into constraint management contracts on a bilateral basis / tender such requirements. Compensation for Access failure may be payable through different contractual routes (BSC or CUSC).

Breaches: Exports above the MEC would incur Overrun charges, which could be expressed as a multiple of the relevant charge rate or in some other fashion, but the overriding principle should be that participants should not be in a position to gain a financial advantage by breaching their rights. Failure to comply with the constraint contracts would result in either a reduced payment to the generator or an additional charge. This aspect requires further work as it was not considered in any detail by the Standing Group.

Compensation for Transmission Failure would be payable by NGC to the Generator. Although not considered in detail by the Group, the initial conclusion was that the level of compensation would need to be agreed between the parties and ultimately subject to Ofgem's jurisdiction. One possibility is that this would be on the basis of a £/MWh compensation rate with the volume (MWh) being determined from the FPNs of the BM Unit that was unable to generate as a result of the Transmission Failure. Work in this area is currently being undertaken under the auspices of the BSC.

Relationships :



An alternative, in respect of Interconnectors, to the above relationships would be for the Interconnector Users to contract directly with NGC for transmission access and pay charges accordingly.

Secondary Trading of Access Rights

Between Generators / Interconnectors at the same node.
Between Generators / Interconnectors at different nodes facilitated by NGC – via a Generation Capacity Exchange Rate Mechanism (ERM) (the principle here being that X MWs of Access Rights at location / node A is equivalent to Y MWs of Access Rights at location / node B).
It should be noted that there may be limits on and/or different "Exchange Rates" for different volumes:

- e.g although 100 MW at location A may be worth 80 MW at location B, 150 MW at location A may also only be worth 80 MW at location B;
- 100 MW at location A may be worth 80 MW at location B, but 200 MW at location A may only be worth 120 MW at location B.

Following the initial allocation, a new Generator would either:

- apply to NGC for additional Access Rights (akin to the current Connection and Use of System application if the station is directly connected or Use of System application if Embedded); or
- acquire rights from an existing generator – and then apply to NGC for Connection, assuming it is a different node. Trades at the same node would require notification to NGC.

The timescale and formalities of processing what is effectively a Modification Application to reduce the MEC or terminate it on behalf of the selling Party and a Connection and/or Use of System application in the case of the new party were not discussed in any detail.

An alternative approach was discussed in which Generators / Interconnectors in suitably designed zones would be able to trade bilaterally without reference to the ERM but trades between zones would still require facilitation via such a mechanism.

In the case of a request for new rights (i.e a new Connection or a new Use of System Offer), either:

- these would not be available to the Generator until the relevant Connection works have been completed by NGC and, conversely, the obligation to pay the Use of System charges would not take effect until the generation plant became operational; or
- the rights to export and obligations to pay, take effect from a defined date after the necessary consents are obtained - this effectively requires NGC to take the buy-back cost risk of transmission system construction delays.

If a Generator wished to close its plant without having sold its rights to another generator either for the same location or via the ERM, its rights would revert to NGC. Whether there should be a “residual” value payable to the generator, how such a value would be derived, or whether the rights would revert to NGC at zero cost, are all issues that were noted by the Group but not discussed in detail.

Duration:

Alternative 1

The right would provide an option to renew the right in the following year provided that the transmission charges had been paid. The implication of this approach is that Generators would not always be able to reduce the GC of the plant to zero for a year or more, thereby avoiding payment of TNUoS, and then return it to its original value at a later date knowing that it had retained the right to do so. Theoretically, as part of the trading process, it may be possible for the generator to sell its rights to someone else for a short term period, but whether this is a practical proposition in reality is more debatable.

Alternative 2

The rights and obligations would be acquired for either;

- defined durations – e.g 1 year, 2 years, 10 years, etc; or
- as requested by the applicant.

Pricing: Two options were considered:

Alternative 1

Either:

Published TNUoS (capacity, locational) + BSUoS (energy, non-locational); or

Published TNUoS (capacity, non-locational) + BSUoS (energy, locational).

Alternative 2

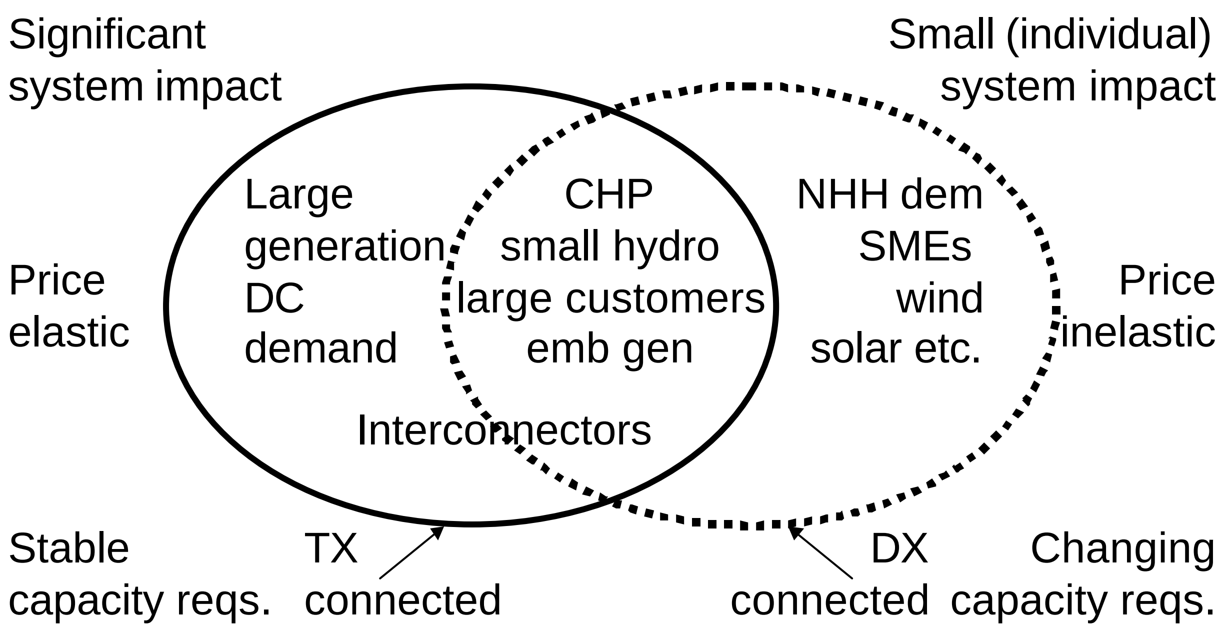
Bilaterally agreed prices for the capacity and the duration of the rights. The BSUoS charge would be charged as currently, although as with Alternative 1 BSUoS could be locational.

"Locational BSUoS" could, for example, be charged as a defined percentage of BSUoS (as currently calculated) to Generators in northern zones and Suppliers in southern zones and the residual to Generators in southern zones and Suppliers in northern zones. Another arrangement for "locational BSUoS" would be to recover the cost of constraints from Generators and Suppliers in the zone in which the constraint arose with all other elements of BSUoS charged on a national uniform basis (i.e a very slight zonal differentiation). Other arrangements could be envisaged but were not discussed by the Group.

4.2 Demand / Exit

Whereas the generation / entry side of the market can be characterised as relatively unchanged in terms of parties desire for capacity (given long term fixed assets), this is not necessarily true on the demand side. If the Contractual relationship were to be between NGC and directly connected Distribution Businesses then the same characteristic could be said to be true. If the contractual relationship is between NGC and the Suppliers then the characteristic is reversed and Suppliers Capacity requirements become rapidly changing (– i.e at customer contract rounds in the Industrial & Commercial retail sector and effectively continuously in the domestic market, allbeit in small quantities in this sector).

Demand Side Model

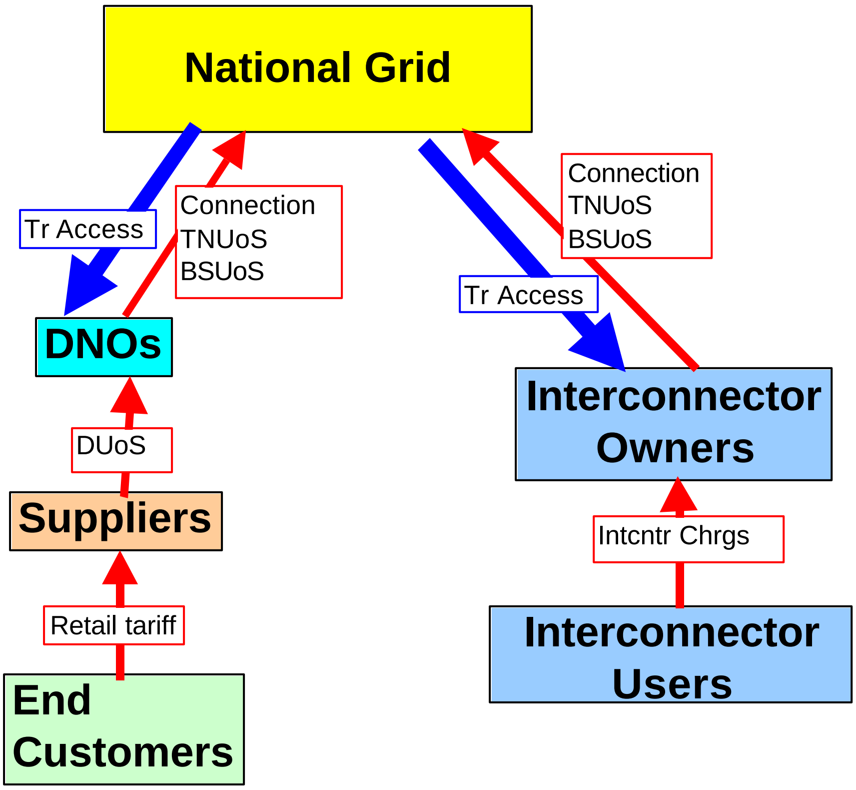


Contractual Options

A range of contractual configurations are possible on the demand side and are summarised below (the order in which they appear has no significance as to the Group's perceived merit of them).

Case 1 – NGC and Directly Connected Distribution Businesses

In this case the Distribution Businesses would contract for firm Access Rights with NGC either for each GSP or for the GSP Group. It is envisaged that the duration of the rights available would be the same as those on the Generation / Entry side.



Although this arrangement would facilitate direct comparison between the Entry and Exit sides of the market, there are several issues that would need to be resolved as to how the demand side Access charges would be passed through to Suppliers and ultimately customers under this set of contractual arrangements. Options include;

- Straight pass through via DUoS charges (in terms of £ total), but how the charges would be structured (i.e the extent to which they are avoidable) could be determined by each Distribution Business separately or a common methodology agreed with the Regulator?
- A form of incentive scheme which would allow the Distribution Business to retain part or all of the difference between an allowed cost and the actual cost and conversely incur part or all of the difference if the outturn costs were greater than the allowed costs – presumably with Caps, Collars and Sharing Factors.

Both routes would require changes to the Distribution Business Price Controls in addition to the DUoS tariffs, but the latter route would also require the creation of an additional incentive scheme component.

Case 2 – NGC and a GSP Group Agent

The GSP Group Agent would be responsible for contracting for an amount of Exit Capacity for the GSP Group for a duration (assumed to be the same as on the Generation / Entry side). Precisely how the Agent would be determined has not been considered in detail. Preliminary thoughts are that the Agent would be selected for a defined period by the Suppliers operating in the relevant GSP Group at the time that the decision needs to be taken. Given that the Agent would presumably be required to provide some surety of payment to NGC, it maybe that those parties wishing to become GSP Group Agents would need to have "pre-qualified" with NGC prior to selection by Suppliers. In a case where one or more of the Suppliers in the GSP Group wished to take on the role of GSP Group Agent, it is assumed that they would be precluded from taking part in the selection process.

The structure of charges used and the level of risk allocated to the GSP Group Agent would be taken into account by the selecting Suppliers. Consequently, it may be that under this type of contractual arrangement that the Agent takes on an explicit obligation to pay for a defined level of capacity for a defined duration at a defined price but charges Suppliers on the basis of their demand on an ex-post basis.

In the circumstance where the GSP Group Take exceeded the capacity nominated by the GSP Group Agent, the Agent would be subject to Over-Run charges and the mechanisms as to how and to what extent these were recouped from Suppliers operating in the GSP Group would be part of the contract terms that were tendered for originally.

Case 3 – NGC as the GSP Group Agent

NGC would act as the GSP Group Agent and would identify the volume of access rights required for each GSP Group as a whole. This could be done on an ex ante basis or, for simplicity, on an ex post basis. NGC would then allocate these rights to Suppliers, within each GSP Group, based on their "proportionate share" of that GSP Group's Take. In return, the Supplier would acquire a proportionate share of the rights and obligations that attach to the GSP Group's rights. The group considered possible options for determining an individual Supplier's proportionate share but, other than noting the need to ensure consistency with the TNUoS charging methodology, did not develop any firm recommendations.

Separately, each Supplier would have the right to identify its access requirements on an ex ante basis and purchase explicit rights direct from NGC. In return, the Supplier would be able to trade these rights (via some form of the Capacity Exchange Rate Mechanism). NGC would then need to adjust the volume of rights available to the rest of the GSP Group. The detailed charging arrangements would need to ensure that there is no incentive for Suppliers to hoard such explicit rights, or for NGC to over or under specify each Group's requirements.

Where, rights are specified on an ex ante basis (whether purchased by the Supplier, or identified on an ex ante basis for the GSP Group as a whole), then overrun charges would apply. As indicated in the discussion on Generators' rights, the overrun charge would need to be set to ensure that Suppliers did not gain a commercial advantage through overrunning.

This case represents the minimal change from the status quo. A majority of the group considered that this was capable of implementation by 1 April 2003, and had the advantage that it could be developed to deliver any of the other three cases, should this be considered appropriate.

Case 4 – NGC and Suppliers

In this case Suppliers would purchase a defined capacity per GSP Group on an ex-ante basis. As their customer demand changes, so too would their capacity requirements. In order to balance their Access positions, Suppliers would need to be able to trade between themselves or with NGC (if it had unallocated rights remaining or the deemed capacity of the GSP Group had been increased). These trades would relate to a single GSP Group. It is not envisaged that there would be inter GSP Group trading.

Implicit within a move to such an ex-ante arrangement would be the removal of the ability of load management customers to avoid such charges (triad avoidance in current terminology). Suppliers would have an incentive to reward load management for avoiding it breaching its level of booked rights, though this value would effectively be capped by the level of Overrun charges.

An alternative approach would be to define the access rights in a different way – e.g the right to offtake up to a maximum capacity at the time of either peak system demand, or the triad, or any other number of highest system demands separated by some defined timescale. This could leave the current Customer Load Management / Triad Avoidance process unchanged but would mean that the definition of rights between Generation / Entry and Demand / Exit would be defined in a different manner.

In order to avoid capacity hoarding, some form of disincentive would be required – a "Use-it-or-Lose-it" concept could be devised in a similar manner to that adopted by the Gas Industry. This would require the use of some defined timepoint such as "Gate Closure" and a central system which received Suppliers "nominations" and "short term" requests. This leads to a requirement to price these "short term" requests and a further mechanism for "recycling" such receipts (as the same capacity will potentially be sold several times).

An alternative approach which might be simpler to implement would be that the Overrun charge on the Exit side would only be payable if the aggregate demand of all Suppliers in the GSP Group exceed the level of booked capacity, otherwise the Suppliers "excess" take would be charged at the price their original allocation is charged at.

Given the typically short term nature of the relationships between Customers and Suppliers it is envisaged that the decision to increase capacity at any individual Grid Supply Point would continue to be driven by the Distribution Businesses based on their aggregate demand forecasts in line with the current Grid Code and Connection Agreement procedures. It could be argued that this process would undermine the intended purpose of tradeable rights as they would have no influence on NGC's investment decisions.

Constraint Contracts on the Demand Side

Although the definition of Access Rights for the demand side is the GSP Group, NGC could enter into bilateral contracts for constraint management, in competition with the generation side, with Suppliers (or possibly directly with Customers). These contracts would relate to interruption at a specific location(s) in the GSP Group. In this way NGC would have sufficiently defined locational knowledge to judge the value of such a contract.

5.0 NGC Price Control Issues

In Pricing – Alternative 1,

- the Transmission investment would be carried out on the basis of providing the minimum capacity as required by the Security Standard against the background of contracted capacity (TO Allowed Revenue).
- The inclusion of compensation for Transmission Failure in the contractual framework may result in changes to the current Price Control regime as this was not explicitly accounted for when the current Control was agreed.
- The Capacity Buy-Back costs and the associated energy costs (including any BM actions) would form part of the SO Incentive Scheme, either in a single aggregate form or as distinct elements.

In the Pricing – Alternative 2, fundamental issues with the NGC Price Control are raised.

- If all participants have a quantity at a price for one to several years ahead in any given year the revenue received will be different to that allowed under the Price Control. This leads to either a necessity to rebate or surcharge some or all Users. If all Users are surcharged or rebated then assuming this is levied in proportion to the original rights (i.e capacity rather than energy), then the originally agreed price is no longer fixed in absolute terms, but would remain so in relative terms (between Users). If no adjustments were made (because all Users had entered into long term contracts) NGC would be left taking much more risk than in the present arrangements as they could be exposed to a shortfall in revenue.
- An alternative would be that only those Users who had contracted for “short term” – e.g 1 year – rights would be eligible / liable for the rebate / surcharge. This would radically alter the risk profile certainly between Users and possibly of NGC depending on whether there is an absolute minimum revenue. This would arise if no party had contracted short term and there was a shortfall against the allowed revenue.

6.0 Additional Discussions

6.1 Interruptible Rights

The concept of interruptible rights was briefly discussed. It was envisaged that a Generator who had a Connection Agreement could be denied access to the system without a compensatory payment. A maximum capacity limit would be specified as with firm access rights and Overrun charges would apply as with firm rights. It was envisaged that the payment would be a discounted percentage of the firm access price. How this percentage would be derived, or what level it might take, was not discussed.

Interruptible rights could be made available either when firm rights for the same quantity cannot immediately be accommodated on the Transmission System, or on request by Users. They would be valid for a finite period (after which time they could be reapplied for). Whilst this type of right has little, if any, value to a new Generator they may have value to a Generator who is considering closing a station and may have sold its rights to another generator. In this scenario it may be considered worthwhile running the plant for an incremental period as a result of reducing the fixed costs associated with the plant. The nature of Interruptible rights on the demand side was not explicitly considered by the Group.

6.2 European Perspective

The group heard a presentation on current transmission access arrangements and proposals in other European countries, the key points of which were:

- UK is already much advanced compared with many other countries and already meets proposed legislation;
- UK has one of lowest average levels of network charge even though the UK has one of the most robust systems (planned to n-2, most other countries only plan to n-1);
- The UK and Nordic countries are the only ones to have liquid wholesale arrangements for system balancing;
- The UK is one of the most active in terms of customers switching suppliers (but full deregulation is only just being introduced in some European countries); and
- The Conclusions of the Florence Forum included the concept that there should be no additional tariffs for Cross Border Trading and that “G” (Generation) and “L” (Load / Demand) charges should be harmonised in the national tariff structures across European countries.

It was concluded that the Group’s deliberations should not be prescribed by what was happening in the rest of Europe at present or in the short/medium term.

6.3 Directly Connected Demand

The application of a revised Access regime to Directly Connected Customers was not considered in detail by the Group. An initial view is that it may be possible to treat them as a special instance of a “GSP Group Agent” or allow the customers at such sites to acquire the Access and deem it to be automatically traded to their nominated Supplier. The application of a revised access regime to Interconnectors taking demand was not specifically considered by the Group.

6.4 Embedded Generation

The issue of licence exempt embedded generators was not considered in detail by the Group. In the absence of any changes to the Licence Exemption Order it is assumed that such generator’s output would be netted off the Supplier’s demand in the case where Suppliers contracted directly with NGC. In the Distribution Business case, it would be necessary to allocate their output to a specific GSP assuming the Distribution Business’s Access rights related to specific GSPs. If the right were to apply to the GSP Group then the exempt generation output would be netted from the GSP Group Take.

7.0 Recommendations to the CUSC Amendments Panel

1. Note the Report.

2. Instigate a consultation with interested parties on the matters set out in this Report.

3. Determine whether or not the Group should further consider details of possible Access schemes such as:
   - the “Capacity Exchange Rate Mechanism” on the Generation / Entry side;
   - the remedy for breaches of rights;
   - the treatment of small embedded generation;
   - the treatment of Trading Units;
   - the treatment of Interconnectors; and
   - further develop the contractual options for the Demand / Exit side, such as:
     - the GSP Agent selection process;
     - the “Use-it-or-Lose-it” process; and
     - the treatment of Directly Connected Demand.

Appendix 1 – TASG Terms of Reference

Introduction

1. Ofgem's Revised Proposals document on Transmission Access and Losses was published on 26 February 2002. The content of the document was discussed at the CUSC Amendments Panel meeting on 22 March 2002. At the meeting, the Panel agreed that a Standing Group should be established under the CUSC governance to consider further the reform of the transmission access arrangements and to identify and take forward the appropriate contractual framework to provide for the new arrangements.

2. This paper outlines the working arrangements and terms of reference for the Transmission Access Standing Group (TASG).

Proposed Membership of the Transmission Access Standing Group

3. The CUSC Amendments Panel agreed to establish the TASG with the following membership:

Chair:	Phil Russell (TXU)
Other Members:	John Capener (British Energy)
	Dick Cecil (London Electricity Group)
	Peter Clubb (GDF)
	Hugh Conway (Energywatch Representative)
	Nigel Cornwall (Cornwall Consulting)
	Richard Court (National Grid)
	Charles Davies (National Grid)
	Nick Frydas (EDF Trading)
	Mike Harrison (Scottish Power)
	Duncan Jack (St Clements)
	Paul Jones (PowerGen)
	David Lane (Clear Energy)
	Phil Lawton (National Grid)
	Simon Lord (First Hydro)
	Keith Miller (Teesside Power)
	Brian Sequeira (British Gas)
	John Stewart (Campbell Carr)
	Malcolm Taylor (AEP)
	David Tolley (Innogy)
	Barbara Vest (RWE Trading Direct)

Note: The above membership was expanded and the actual attendees at each of the meetings is recorded in the Minutes, available on the NGC CUSC Website.

Meeting Administration

4. The frequency of TASG meetings shall be defined as necessary by the TASG chair to meet the Terms of Reference and time scales as defined below.

5. National Grid will provide technical secretary resource to the TASG and handle administration arrangements such as venue, agenda and minutes etc.

6. The TASG will have a dedicated page under the CUSC section of the National Grid Industry Information website. This will enable TASG information such as minutes and presentations to be available to a wider audience in a timely manner.

Terms of Reference

7. The TASG has been established and actioned to consider further the reform of the transmission access arrangements and to identify and evaluate the options for changes (consistent with Ofgem's 'Transmission access and losses under NETA – Revised Proposals' document) and their implications for the CUSC and other industry documents.

8. The Standing Group should review the points set out in Section 4 of Ofgem's February 2002 paper on Transmission Access & Losses as they relate to the current access arrangements and in particular should review:
   - the 'firmness' of the allocated rights to all Users who use the transmission system (also need to clarify the Maximum Export Capacity and demand side rights of Parties and clarify what obligations exist with regards which category of transmission charge that has to be paid by Parties for the allocated rights);
   - how allocated rights for use of the transmission system are enforced (i.e. how it is ensured that Users have the correct agreements in place with National Grid and how they comply with them) and how the allocated rights are monitored and settled;
   - compensation for constraints, failures and disconnections;
   - the duration and quantity of the rights allocated;
   - the inter-relationship and linkage to other industry arrangements, and
   - the potential for the trading of any allocated rights between Parties (e.g. facilitating novations of connection agreements);

9. In progressing the issues raised above, the TASG should be cognizant of any work undertaken in relation with arrangements for Transmission Access in other industry work streams (e.g. transmission losses under the BSC, cost signalling under the Charging Forums and SO Incentives under the Licence). Furthermore, the TASG should be mindful of any interaction between the Transmission Access arrangements and any other relevant issues being considered by the industry (in particular those relating to BETTA, European Developments e.g. Cross Border Tariffs and the Government's Energy Review).

10. The Standing Group Chairman will be responsible for providing a verbal report on the Standing Groups progress with regards the issues raised above at each Amendments Panel Meeting. Furthermore, the Standing Group Chairman will be responsible for producing a Standing Group Report. The report should be submitted to the Panel Secretary by 8th August 2002 for circulation to Panel Members and the Conclusions of such report should be presented to the Amendments Panel meeting scheduled for 16th August 2002. The report should be written with reference to Section 8.18 of the CUSC.

11. It should be noted that, in accordance with Section 8 of the CUSC, the TASG itself, as a Standing Group under the Amendments Panel, is unable to propose an amendment to the CUSC.

Relationship with Amendments Panel

12. The TASG shall seek the views of the Amendments Panel before taking on any significant amount of work.

13. Where the TASG requires instruction, clarification or guidance from the Amendments Panel, particularly in relation to their Scope of Work, the Standing Group Chairman should contact the CUSC Panel Secretary.

Meetings

14. The Standing Group shall develop and adopt its own internal working procedures and provide a copy to the Panel Secretary.