

Report from the Transmission Access Standing Group to the CUSC Panel

EXECUTIVE SUMMARY

To be completed after the body of the report

NOTES TO FELLOW TASG MEMBERS.

- *Please provide comments before end of Wednesday 3rd September*
- *If you have comments on the text itself, please use Tracking and mark up any changes you want to make.*
- *If you have comments, but are not suggesting drafting, as such, please supply comments in {in italics} adjacent to the appropriate section*
- *I will take account of any comments or proposed changes in formulating the final report, but do not promise to use your precise text*
- *If you have a major issue please raise it sooner rather than later, so that I can air it at a group meeting.*
- *Please assume that Richard and I will fill in the non-contentious bits and appendices.*
- *I am happy to take further written comments on Competing access and Breach, but intend to focus discussion only on the other parts of the report on 5/12th September.*

1. INTRODUCTION

On 20/03/03 Ofgem published the agreed Systems Operator Incentive Scheme for the period April 2003-March 2004 (ref 16/03). Within the scheme document NGC gave a number of undertakings, including to review transmission access arrangements and if appropriate bring forward change proposals for the CUSC and/or charging methodologies (See Appendix A). The approach taken is incremental evolution from the current position, not radical transformation. As part of this undertaking the terms of reference of the CUSC Transmission Access Standing Group were modified (Appendix B) and the Group has considered some of the issues identified in the SO Incentive Scheme Document. This report is the product of the process.

2. STANDING GROUP PROCESS DETAIL

2.1. Terms of Reference and membership

See Appendix B

2.2. Group Process

See Appendix C

2.3. Related Matters

- The work of the TASG has to be seen in the context of a variety of other regulatory and legislative initiatives, in particular:
 - The Transmission Charging Methodology Forum is reviewing the connection and network use of system charging methodologies with a view to proposing a number of changes for implementation in April 2004;
 - The BETTA legislation and process envisages the need establish common approaches to connection and use of system across E&W and Scotland;
 - BSC Modifications P80/87 (currently with Ofgem for decision) propose means of dealing with the failure of provision of transmission access under certain circumstances

- CUSC Amendment CAP048 seeks to address the recompense for removal of the provision of transmission access;
- The recently passed EU directive on electricity market liberalisation looks forward to the development of proposals for cross border, congestion charging, and Generation/Load charge split harmonisation for use of system across the EC.
- It is not within the terms of reference of a Standing Groups to propose CUSC amendments.
- The issues of breach and competing access are dealt with within TASG to reflect the post-CAP043 world in which generation has a commercially firm right of access of a defined level. Additionally, the TASG has attempted to consider solutions that would work in the event that firm exit capacity is introduced.
- During the assessment of CAP043 National Grid produced a 'roadmap' of the "Building Blocks" which it considers needs to be in place for the introduction of a transmission access regime. This is a useful visual aid and is reproduced in (this *needs sorting* Appendix 2 of Appendix A to this report)

3. STANDING GROUP WORK PROGRAMME

Three elements were identified to the work programme:

- Big Picture issues: definition of exit capacity, roles of DNO and supplier in managing exit capacity, possibility of firm and non-firm exit capacity existing alongside each other.
- Competing Access
- Breach of Access

The elements were progressed together.

4. COMPETING ACCESS

4.1. Statement of the problem

When any two separate applications are made seeking new connection capacity to the NGC transmission system at approximately the same time, they may potentially be in competition. Competition may equally arise if parties are seeking to increase their existing agreed firm commercial right of access and even if the changes sought are at geographically widely distant points, This arises because of the interconnected nature of the transmission system and the time that may be required to expand its capacity. NGC has a licence obligation (Condition C7D) to offer connection and access terms to all the new and upgrading parties. Therefore NGC needs a fair and practical means within the CUSC to deal with the issue of competing requests for transmission entry capacity whilst still satisfying its licence requirement under special condition AA4 of the transmission licence to "operate the transmission system in an efficient, economic and co-ordinated manner" and additionally, whilst still satisfying its statutory duty under Section 9 (2) of the Electricity Act 1989 to "develop and maintain an efficient, co-ordinated and economical system of electricity transmission".

4.2. Current Position and issues

- There is a queuing approach for additional capacity
- Competing parties are informed at time of offer to second party
 - Party's applications for other approvals (e.g. Section 36) are made public, although this is frequently well after connection offers have been made and there is no hard and fast relationship between the timings for connection offers and Section 36 applications. In any event the timing of information

coming into the public domain is to some extent under the control of the developer.

- First party (A) to sign gets an offer assuming that the competitor (B) does not exist. This may or may not be the date that they applied for.
- Second party (B) to sign gets a revised offer with a date that may be later than their preferred connection date if NGT is not able to meet the requested date. It may also be a completely different scheme with different charge as well as date implications. (It should be noted that the shallower 'plugs' methodology would probably result in smaller differences between connection charges, if implemented.)
 - Competing parties may wish to cooperate in reaching a mutually acceptable 'third way', if they are aware of each other's plans.
- Currently there is no involvement of any existing connectees
 - Release of entry capacity by existing power station sites may be a useful alternative to new asset investment
 - Increases in exit capacity may be a further alternative
- Usually the connecting generator lodges a TEC from the Charging Date, as defined in the Connection Agreement. Where this involves multi-staged commissioning, particularly of larger plant, it is conceivable that another existing connectee might wish to 'nip in' and lodge a TEC before, say the second stage. NGC would generally expect that the new connectee would have booked the use of the transmission system once the Connection Agreement is signed.

4.3. Option 1 'Bulletin Board'

- An evolutionary change from status quo that would probably enhance efficiency of current process
- All new applications are made public at time of application
 - Existing parties who might release entry capacity would become aware as well
- Party (A)
 - Retains the advantage of being first because it's still a queue
 - Gives clarity of understanding level of activity in an area
- Party (B)
 - Knows of other applicant, but can proceed with full knowledge
 - If believes can't compete, application may not be made
- Enables competing projects to be aware of position from earlier stage
- Allows users to identify unfacilitated trading opportunities at the same gsp and potential facilitated trading opportunities at other locations
- Gives option of seeking a 'third way', or doing a deal with an existing connected party
- In principle increased demand may offer another alternative to do a deal. In practice, infrastructure development to date has been driven by new generation projects because of their 'lumpiness'
- Closure of embedded generation may facilitate HV connection locally.
- Interconnections are typically a different issue.
- Still a queuing system
 - Equity demands that the relative positions in the queue remain
 - First applicant (A) gets first offer.
- Public domain is a double-edged sword
 - Might encourage pre-emptive spoiling applications
 - Impossible to remove all risk of this
 - But may occur anyway if other parties become aware of the project

- And possibility of Competition Act referral (**CAN NGC/OFGEM PLEASE CLARIFY FOR ME!**)
- But substantial financial (but fair!) and resource commitment required to develop a proposal

4.3.1. Pros and Cons

- Pros
 - Applications made/withheld with full knowledge
 - Could lead to more efficient use of resources
 - Could encourage trading offers (dependent upon User requirements)
- Cons
 - May encourage spoiling applications
 - May push people to apply late against required construction lead times
- Issues
 - What information should be published? As a minimum, the TASG would expect: the value of TEC sought, the name and location of the site, the date the TEC is required from; the name of the Applicant and probably the nature of the station's technology (**NGC TO CLARIFY IF THIS IS DIFFERENT FROM WHAT THEY MAKE PUBLIC NOW, PLEASE**)
 - This option is more complex than the status quo. Is it more efficient?
 - For example, 1MW at node 1 not equal to 1MW at node 2

4.4. Option 2 'Facilitated Trade'

- A further evolutionary stage from status quo
- National Grid would identify existing users whose rights are tradable with a potential new user.
- The extent of the trade off would also be identified, i.e. how many MW at one site equivalent to how many at another
 - NGC needs to be involved to determine 'exchange rate' and any other trade issues
 - Snapshot possible, but trade always need to be done individually
 - There is likely to be a minimum materiality of impact hurdle, below which NGC would not consider a contribution from another site.
 - There is likely to be iterative exploration of options
- Under Option One this could be an open activity undertaken at the time of application; under the current arrangements it would either have to wait until the connection agreement was completed or would have to undertaken on a confidential basis
- The new user would then have the opportunity to purchase existing rights off an existing user. The value of such rights would be the value to the new user of avoiding the queue (i.e. arising from the time value of money from the income stream starting earlier, and from the developers' and lenders' expectations of change in risks with time), not the value of the rights themselves, as TNUoS would still be payable. There might also be cost and charge advantages depending on whether less physical work was required and the nature of the charging arrangements.
- NGC offer will be conditional upon parties agreeing terms

- NGC would not need to see any contract between parties because it would see the reduction in TEC by the selling party.
- One simple method would be for a bilateral contract between the parties who are trading rights and this contract would effectively be for (in exchange for payment) one of the parties to surrender some of his rights. The latter would be achieved by that party modifying his TEC agreement with NGC.

4.5. Other Issues

- The potential requirement for such a process has not occurred frequently in E&W over the last 2-3 years, although anecdotal evidence suggests it has been more frequent in Scotland.
- Process cannot be easily 'commoditised'
 - Capacity Exchange rates will vary profoundly between locations and with time
 - Daily publication by NGC of a 'Transmission Access Opportunities Map or Matrix on a nodal or Zonal basis to inform access application decisions by generators is unlikely to be practicable for the reasons described above
- Shallow connection policy and costs
 - Full costs of new connection are split between infrastructure and site specific ('plug model' just makes this more extreme)
 - A deal between new connectee and existing (or other new player) only concerns value of shallow connection costs; infrastructure costs are borne elsewhere. Therefore, total costs of upgrading the network may not be optimised
 - Trading fee agreed between the two parties will therefore not take into account the total costs of the new connection and associated infrastructure
 - However, NGC's licence obligation will result in NGC taking the full costs of infrastructure and connection into account in developing an offer. **{NGC PLEASE GIVE ME CORRECT REF TO COST-EFFECTIVE DEVELOPMENT OF THE GRID}**.
 - This could lead to dispute between the Parties and NGC, but in that event they could refer NGC offer to Ofgem if NGC offer was not acceptable and hence there would be regulatory oversight of the process.
- In event that firm exit rights can be defined, demand side may have a realistic part to play here. This could include Licence Exempt Generators via a Supplier.
- Licensed embedded plant already has a contractual agreement with NGC, albeit for TNUoS alone, and so, could participate directly in either of these two options above
- In the event that these options result in a greater work load for processing applications NGC would wish to revisit charges.

4.6. Applicable Objectives

- Both the Bulletin Board and Facilitated Trade options are advances on the status quo with respect to the 'efficient operation of the system' **(INSERT CORRECT QUOTE PLEASE RICHARD)**
- Additionally they should both facilitate competition by making market entry and exit easier, cheaper and faster.

5. BREACH OF ACCESS RIGHTS

5.1. Statement of the Problem

Post CAP043, generators purchase a contractually firm right of access up to the value of their TEC. In the event that generators exceed their TEC they have breached their contractually firm right of access. What should be the consequences of such breach? Can access rights on demand side be defined so that breach becomes meaningful?

5.2. Current Position

- Breach of CEC or TEC is breach of CUSC and also breach of the Generator's licence
- Breach of CUSC typically leads to:
 - Notification by NGC (copied to Ofgem) to the breaching party seeking explanation and statement of remedial actions planned and already undertaken;
 - Repeated failure to remedy breach of the CUSC is reported to Ofgem;
 - Remedy for breach of licence by Ofgem can be 10% of turnover or **(IS IT OR, OR AND, AND WOULD THE PROCESS BE 10% TURNOVER AND THEN LOSS OF LICENCE. NGC/RICHARD FORD CAN YOU CLARIFY PLEASE)** loss of licence, i.e. 'nuclear' options
- There is a possible reinforcement via making 'exceeding rights' a breach of the Grid Code but penalties would be the same as above

5.3. Issues arising

- TNUoS recovers costs on an equitable basis reliant on honest declaration of expected usage
- Disconnection by NGC of generator (CAP048) may lead to compensation
- Demand side currently undeveloped, but likely to have choice of firm or non-firm exit capacity
- A market for trading access and therefore optimizing short-term is not available, nor expected to be available in the near future.
- Sometimes an error zone may be useful (MAXGEN type situations)
- Breach of firm access rights may or may not lead to any additional operational costs depending on the state of the system and the nature of the breach
- Simple 'penalty' is unlikely to be accurately cost-reflective¹
 - The costs of acquiring additional TEC 'honestly' will include the costs of application and waiting for at least 3 months
 - The operational costs will vary with the situation

5.4. Possible Way Forward

- First issue to be considered is generator side; demand side needs to establish principle of rights first, but approach should be consistent with firm demand-side rights.
- Ideal solution:
 - Parties incentivised to purchase/declare honest TEC ex ante
 - Equity between parties
- What is an appropriate commercial basis for breach of rights?
- Options for a commercial basis:
 - Option 0: Pay nothing for breach

¹ Ofgem have apparently blessed a multiple of demand side UoS charges for a DNO (*Richard F can you enlighten me as to the cost-reflectivity argument here please*)

- Equity problem compared with those who declare TEC honestly
- Option 1: If no value can be ascribed to the right at the time and no implications for SO of breach by G then nothing other than the additional TNUoS costs
 - Equity problem compared with those who obtain TEC honestly ex ante
 - Parties may avoid risk of over-contracting for TEC by letting TEC ratchet up to the highest actual recorded.
 - Is this analogous to non-firm exit-side access rights?
 - NGC will lack quality information on system use (**IS THIS AN ISSUE CHARLES?**)
- Option 3: Extent of breach of TEC considered as non-firm rights,
 - No compensation if they are removed, although difficult to see how they could be
 - Party pays TNUoS for actual use
 - Party pays balancing services cost attributable to his action
 - Provided costs can be identified, otherwise some reasonable estimate?
- Option 4: 'Penalty' is levied
 - For example, energy exported beyond TEC is valued at zero in BSC
 - Party also pays TNUoS for extra TEC (even in -ve zone)
 - Party also pays balancing services cost attributable to his action
- None of the above options 'cure' the breach and so the remedies listed above in section 5.2 would still apply, particularly if the breach remained and/or were repeated.
- If commercial incentives are considered appropriate then what happens to the revenues?
 - Additional costs excluded from SO Incentive cost base because NGC not expected to manage such unexpected effects and therefore shouldn't be judged on them
 - Additional BSUoS costs paid for by breaching party used to offset BSUoS for others
 - Additional TNUoS paid by breaching party recycled through K factor and therefore reflected through lower TNUoS.
 - Any other payments by breaching party are recycled to other parties. (via BSUoS?)

5.5. Other Issues

- Does existence of firm + non-firm demand-side model allow meaningful concept of breach to be developed as the effect of breach would be similar to another party acquiring an additional volume of non-firm rights?
 - Yes but note that the demand that was firm had to be discretely identified i.e. metered as a separate entity from other demand
- Can costs arising be unambiguously allocated? If not, then what is the basis for a cost-reflective approach? If there is no uniquely correct approach, then one has to develop some rules
- What happens if breach 'helps' system? Clearly one needs special rules for things like maxgen.
 - Could have an error zone of say +2%, before penalty kicks in
- The existence of a short-term access market would help parties to avoid breach.

5.6. Conclusions

- Equity and orderly management of the system require incentives to avoid breach
- Current remedies range from minor 'name and shame' through to 'nuclear' loss of licence
- Some options and precedents for 'penalties' for breach have been identified.
- The TASG was unable to reach agreement on which of the above options was preferable.

5.7. Applicable Objectives

- Facilitate efficient operation of the transmission system via:
 - Optimising use of system capacity
 - Encouraging short-term transparency and accuracy of usage of system capacity by generators (and demand-side, if developed)
 - ***Anything else? I am happy to take further comments on applicable objectives please.***
- Facilitate competition between generators and between suppliers
 - Encourages equity in use of transmission system
 - ***Anything else? I am happy to take further comments on applicable objectives please.***

6. BIG PICTURE ISSUES

In the next sections a number of larger issues are addressed:

- Definition of Firmness of access
- Treatment of exit capacity
- Roles of Supplier and DNO as Potential Access Managers
- Treatment of Interconnectors
- Duration of access

7. Definition of 'Firm' and Allied Attributes

In order to develop transmission access, it is essential to understand what is meant by Firmness, particularly as applied to the exit side.

Firm: Four essential features identified for firm contracts:

- There must be a pre-existing contractual relationship between the provider and the user
- Compensation should be payable in the event that [the access contracted for is not received](#) by the user
- Commitment and Volumes must be defined before the event
- Volumes can only be taken up to the volume defined ex ante (maximum volume) and must be paid for

Time

- Sensible unit of time is Settlement Period - practical approach to unit pricing granularity

Payment

- Two options on payment. Either:
 - Pay for the entire volume contracted for; or
 - Pay up to the volume taken with the balance subject to a separate charge (which might be zero)

Compensation

- For compensation purposes unsupplied capacity could be measured by the failure to meet the contracted requirements of the User. The User should however have confirmed the need for that contracted capacity on the day. Need to find a way to demonstrate that contracted volumes have not been

delivered to receive compensation - you don't know if it was deliverable until after it was delivered. The issue is how do you know it was not delivered

- Another way of looking at compensation would be take the view that NGC has been provided with sufficient income through the regulatory contract to provide an efficient system and meet security of supply requirements so that compensation for unsupplied demand was unnecessary. I do not understand this. But "User pays" model difficult to reconcile with this approach.

Tradability

Tradability not an attribute of firmness, but rather firmness is probably a pre-requisite for tradability

8. Exit Capacity

Development of Transmission Access has, to date, not considered exit from the transmission system. Customers either have half-hourly metering (HHM) or not (NHHM). Some of the HHM customers have controllable load, as do some of the NHHM (teleswitched load). To date NHHM demand has been limited only by the physical capacity of the network. Suppliers estimate NHHM load, all load is controllable. I think what is meant is controllable by the supplier or NGC or DNO (or is it?) but ~~its~~ an individual supplier's usage of the transmission system is paid for on the basis of outturn demand of its customers. It has not been firm (see above) in the sense described above. However, to the extent that suppliers in aggregate will pay for 75% of the cost of the network provided in accordance with the planning and operating standards it is arguable that they have paid for a pre-defined volume and standard of access. The current mechanism can be thought of as a mechanism for allocating the costs of this access to the suppliers of the customers that benefit from it and the ex post payment mechanism as a means of ensuring that the access rights, and payment for them, follow the customer.

Exit capacity is most likely to be defined in terms of demand zones. These are not the same as generation zones. This will present problems if changes in demand and generation access are to be treated as opposite but equivalent.

8.1. Firm Exit Capacity

8.1.1. Why Firm Exit Capacity?

- Enables compensation against network failure
- Provides cost certainty (incl. constraints) and risk management if longer term rights are available
- Tradability will enable within year adjustments and switching
- Parity and equity with generation

8.1.2. Attributes of Firm Exit Capacity

- Initial allocation offered by NGC
- (Note that for generator choice is between firm rights and no rights; for exit capacity the choice is between how much firm, how much non-firm and which customers are covered by which) It is not an attribute of firmness as such.
- Entity acquiring rights: Supplier or directly connected customer (DCC) or DNO
- Volume of rights: As agreed up to limit of connection (note we mean agreement that deals with connection and use of system) agreement
- New provision of rights: new/amended agreement with NGC
- Surrender of rights: Buy back by NGC as SO
- Duration of rights: annual or longer up to connection contract term
- Price of rights: TNUoS initially, plus market rates subsequently
- Trading of Rights: physical market

- Compensation for non-provision: similar to generation, CAP048 starting point
- Breach: similar to generation (although split of firm/non-firm may complicate this?)
- Consumption right expressed as MW in any half hour
- Defined within TNUoS/GSP zone
- Definition ex ante and annual, but could be shorter or longer

8.2. Non-Firm Exit Capacity

8.2.1. Why Non-Firm Exit Capacity

- Supplier can only forecast demand, not determine it precisely ex ante
- Supplier cannot control NHH demand except to physically-determined maxima, or via teleswitching-type technologies

8.2.2. Attributes of Non-Firm Demand

- Initial allocation: Offered by NGC but take-up optional surely compulsory that any demand that is not firm "takes up" (whatever this means) non firm access
- Entity acquiring rights: Supplier or directly connected customer (DCC) or DNO
- Volume of rights: Capped at physical limit of connection assets/network. (This can only be known in aggregate ex ante, so how is it allocated between suppliers? Is this a problem in reality?)
Actuals known ex post
- New provision of rights: new/amended agreement with NGC
- Surrender of rights: No control possible by Supplier, so not meaningful concept
- Duration of rights: annual or longer up to connection contract term
- Price of rights: TNUoS
- Trading of Rights: physical market only at point of change of supplier
- Compensation for non-provision: what basis?
- Breach: beyond physical limits network operator will remove access, probably to more than one suppliers' customers
 - Impossible to achieve in short term for an individual customer
- Consumption right: expressed as MW in any half hour ex post measured
- Defined by TNUoS/GSP zone
- Definition ex ante cap (physical connection limit) and annual, but could be shorter or longer. I think once one defines a physical connection limit one is in to firm rights. Consider what physical connection limit means for a supplier with embedded customers (I think meaningless concept)

The issue is the co-existence of firm and non-firm access rights for the demand side. It is both possible and desirable for firm and non-firm to co-exist but that it is necessary to clearly identify which customer groups the firm rights apply to by, for example, specifying the individual BMUs to which the firm rights apply. (I don't believe that this needs to be fixed for ever - the supplier could buy the firm rights and then make a nomination in some predetermined timescale). If you don't do this, and a supplier holds a portfolio of unallocated (other than by GSP Group) firm and non firm rights then, in effect, the non firm rights start to look very like over-run charges as that is what the supplier would pay for any demand that exceeds its firm rights. You are then into the issue of pricing. If the non firm rights are priced at the level overrun charges would be set at then this is no different to a fully firm arrangement and removes any benefit that might accrue to

a firm/non firm approach. If you go in the other direction where firm and non firm rights are priced on a similar basis then I would expect suppliers to buy firm up to a level they are confident they will exceed (to get an entitlement to compensation for access failure) and buy the rest non firm – in practice (apart for an entitlement to compensation) this looks very like the current arrangements

Also it's implicit in the comments on consequences of overrunning that the overrun charge will need to be zone or GSP group specific – it might be helpful to make this explicit.

9. Supplier as Access manager

Most Suppliers have HH and NHH metered customers across a number of gsp groups. It is likely they would have to have a portfolio that contained both firm and non-firm customers. The concept of firm exit capacity is novel and only a limited number of types of customers could easily be accommodated as firm.

- In principle Suppliers would choose how much firm and non-firm in any gsp group
- Firm access gives rights to compensation if rights are removed and obligations regarding breach. Therefore ~~f~~Firm rights must be verifiable.
- In practice a supplier would only be able ~~have~~ to nominate identifiable meter systems whose consumption can be verified on a settlement Period basis as firm.
- This suggests individual NHHM customers would be excluded. However, if a NHHM load can be teleswitched (i.e. controlled) and its aggregate demand known across, say a gsp group, could this be nominated as firm demand? **What do you think?** {Can the teleswitched consumption be verified on a half hourly basis? If not then it fails the test in bullet 3 above and could not therefore be nominated as firm – it would be difficult to separate from non-firm NHHM I think.} **Breach can be measured as its demand would be higher than rights purchased. However, on what basis would you be able to treat the additional demand any differently than someone who consumed non-firm demand (assuming it is on the ex-post basis as now)? The result is the same.**
- It might depend on whether the aggregate demand was known on a half hourly basis.
- Supplier would nominate the remainder of its NHHM load as non-firm. It might also nominate HHM demand for which firmness confers no benefits

There is still a difficulty in measuring a removal of rights. If part of a GSP Group is de-energised or subject to voltage restrictions, it is not possible with current settlement systems to link this back to individual suppliers and their BMUs.

9.1. Assessment against Applicable Objectives

- Facilitate efficient operation of the transmission system via:
 - Optimising use of system capacity
 - Encouraging short-term transparency and accuracy of usage of system capacity by suppliers
 - **What else?**
- Facilitate competition between suppliers
 - Encourages equity in use of transmission system
 - Enables differentiation on grounds of attitude to capacity risk
 - **What else?**

10. Distribution Network operator as Access Manager

DNOs need to know more about the future pattern of demand than Suppliers in order to plan and build it. They already contract with NGC for NGC Connection and are best placed to optimise contract for use of the rest of the network {I don't agree and would be a bit concerned if it was being put forward as the view of the group. Suppliers are in the best position to ascertain the relative worth of access, compared with contracting with a distributed generator for instance, taking into account all things such as transmission losses, energy prices and imbalance risk. The DNO cannot make any of these tradeoffs, is not set up to do so and it would be unreasonable to expect it to. You could provide signals to suppliers via DUoS, but why create another level of transaction costs? At the moment it reads as if there are problems with the supplier based solution but not the DNO. I think that both are problematic and that it's the concept of firm rights which is the main problem.}

- Pass-Through Option
 - DNO trades firm and non-firm access with NGC, based on aggregate of Supplier nominations for the gsp group
 - TNUoS charges are passed through
 - Suppliers can nominate firm and non-firm access to DNO as above (this would become a matter of DUOS charging so is outside the scope of transmission access)
 - DNO has no risk/no incentive to manage access with NGC
- Incentivised Option
 - DNO trades firm access with NGC (or a greater proportion firm than he trades with Suppliers)
 - Suppliers can nominate firm and non-firm access to DNO as above (this would become a matter of DUOS charging so is outside the scope of transmission access)
 - TNUoS charges may not be a simple pass-through, may be DNO incentivisation scheme
 - DNO is incentivised to make more efficient investment in distribution, and to manage load around distribution network in an active way
 - DNO is incentivised to ensure NGC make more efficient transmission investment

10.1. Assessment against Applicable Objectives

- Facilitate efficient operation of the transmission system via:
 - Optimising use of system capacity
 - Encouraging short-term transparency and accuracy of usage of system capacity by suppliers via DNOs
 - But additional level of complexity for suppliers/DNOs may offset efficiency gains {?}
 - **What else?**
- Facilitate competition between suppliers
 - Encourages equity in use of transmission system
 - Enables differentiation on grounds of attitude to capacity risk
 - **What else?**

11. Interconnections

11.1. Statement of the Problem

The treatment of Interconnectors is difficult and can be argued to be more than the simultaneous allocation of entry and exit rights in a manner similar to generators and demand. How can they best be treated? A number of options were identified. , that tried to recognise the benefits the interconnectors bring to the market, for the costs to be borne by the appropriate parties and for maximum trading opportunities to exist. This issue has to be developed with the aim of being consistent with the rest of the UK system and the EC proposals. It may be necessary for compromises to be made in order that there is no Undue discrimination to the Interconnector Owners or Users.

11.2. Options for Solution

Four possible models have been highlighted as means for dealing with Interconnectors:

- Model 1: Transmission Company owned Interconnectors becoming transmission infrastructure – no TA charges, only capacity auction fees set against regulated return.
- Model 2: Merchant Interconnectors with any additional transmission infrastructure reinforcements kept within transmission infrastructure – but no TA charges passed through. Capacity auction fees would be set against business costs.
- Model 3: As above, with Interconnector Owners facing TA charges but not passed through to Interconnector Users Capacity auction fees provide the income.
- Model 4: As above, with Interconnector Owners ~~and Users~~ pay able to recharge TA charges through to the Interconnector Users

The current methodology is built around model 4, but new EC Directives may force a rethink of the methodology such that one of the other models is more appropriate. It could also be argued that one of the other models is more appropriate under NETA in any case.

How do we choose the best contender(s)? Trouble is that depending where you are in the market place you will have a different view of which one is best. I believe models 1, 2 and 3 all have merit over and above 4.

Common Attributes envisaged for any of the models within a TA regime are::

- Contracts for capacity would be one-way
- Interconnector access rights would automatically include Transmission access rights i.e. there would only be one auction.
- Firm contracts up to the full capacity of Interconnector in each direction.
- Non-firm products would be available beyond the full capacity, contingent upon offsetting contracts in the opposite direction.
- No uncertainty of charges (however small or large) before capacity auctions.
- Access to the markets in all timescales (this is as much a feature of market rule compatibility as access to interconnectors.
- Capacity buyback (importing or exporting) operates only through the Interconnector Users once the capacity rights have been obtained and through the Interconnector Owner before the auctioning of those rights.

12. Duration of Access

Access is currently purchased on an 'evergreen' basis. Holding and paying for a TEC of a given volume automatically entitles the holder to an option for the same volume (or less) in the following year. The option is exercised by agreeing to be subject to TNUoS. There are alternative approaches to determining duration:

- Fixed periods of prescribed start date

- Periods of greater or less than one year
- Periods that begin some prescribed date in the future
- **What advantages do parties see for options other than evergreen?**
The Interconnector Owners will be interested in evergreen rights only. The Interconnector Users on the other hand have to have daily rights upwards, depending on the length of the interconnector capacity agreement.
Gives NGC knowledge that can sell right to somebody else at end of fixed period bought. May allow long term charges that are known in advance

13. Portfolio TEC

- Generators may seek 'portfolio TEC' to mix firm and intermittent sources or other combinations e.g. gas and coal plant. This would avoid the requirement for licensable intermittent generation and its associated reserve plant from being forced to pay for their full capacity, even when it was clear that they would not both run at full capacity simultaneously.
- If a generator has intermittent plant on the distribution network, then this problem is further complicated because the reduction of intermittent generation would be seen as an increase in demand within a demand zone, whereas the associated reserve capacity on the transmission network will be in a different generation zone. This raises the general problem of how reductions in demand can be managed as equivalent to increases in generation, and vice versa.
- How do NGC know who held the rights at a particular point in time?
 - They need to ensure that (annual) TNUoS liability is paid
-

14.

Appendix A: Excerpt from SO Incentive final document quoting NGC's commitments re Transmission Access

"NGC's Commitments"

- 6.13 NGC has a number of existing obligations in respect of developing, maintaining, operating and charging for the transmission system as follows:
- Under Section 9 of the Electricity Act, it has a duty to develop and maintain an efficient, co-ordinated and economical system of electricity transmission;
 - Under special condition AA4 of the transmission licence, it has an obligation to operate the transmission system in an efficient, economic and co-ordinated manner;
 - Under Condition C7 and C7A of the transmission licence, it has an obligation to develop a use of system charging methodology and to keep it under review at all times and make such modification as may be requisite for the purposes of better achieving the relevant objectives (these latter including compliance of the methodology with facilitation of competition and with cost reflectiveness); and
 - Under Condition C7B it has analogous obligations with respect to connection charging methodology
- 6.14 In light of these obligations, NGC has committed to use all reasonable endeavours to review and, if appropriate, bring forward proposals for reform of the contractual framework and charging methodologies, for implementation in 2004, in respect of:
- Charges for the provision of connection to the transmission network that represent the cost of connection attributable to a single user, and that encourage competition in the provision of connections;
 - The investment cost signals given by the Transmission Network Use of System (TNUoS) charges, specifically to looking at the marginal costing method and the locational signals provided by the charges;
 - The time period over which TNUoS charges apply, looking specifically at the charges applicable to periods of less than one year and greater than one year;
 - The treatment of competing requests for new transmission capacity in the offer and modification process set out in the CSUC;
 - The treatment of licence exempt embedded generators and the appropriate recovery of costs which they impose on the transmission system, against the background of policies designed to encourage the development of such generation; and
 - The provision of firm transmission rights, compensation for disconnection and remedies for breach of rights.
- 6.15 Whilst NGC will be considering firm transmission rights in respect of both entry and exit, the transmission Access Standing Group during 2002, and recent Charging Methodology discussions on modifying the triad charging mechanism, have identified a number of complex issues associated with exit capacity, including those associated with the facilitation of competition in supply. Given these issues, NGC believes that the identification of a solution

for exit arrangements is likely to be more problematic than for entry, with implementation of any comprehensive solution by April 2004 unlikely.

6.16 However NGC recognises that it is important that, as far as possible, progress is made on the exit arrangements, in line with its commitments on other elements of the contractual framework and charging methodologies. NGC will therefore initially focus on, and, if appropriate, bring forward proposals in respect of:

- The charging base upon which to levy demand TNUoS charges; and
- The basis for the calculation of demand TNUoS charges.

In addition to and in parallel with NGC's review, Ofgem intends to invite views on NGC's transmission charging methodology, so as to be in a position to assess any proposals for change that NGC brings forward. It is Ofgem's view that the combination of NGC's existing licence obligations, NGC's commitments and Ofgem's own charging methodology review provide sufficient assurance that significant developments, consistent with the trust of Ofgem's reform principles, will be in place by 1 April 2004, in time for the introduction or revised incentive arrangements, i.e. Phase 2."

Appendix 2: Transmission Access Round Two - Relevant Points

1. CUSC Applicable Objectives

- a. The efficient discharge by the licensee of the obligations imposed upon it under the Act and by this licence; and
- b. Facilitating effective competition in the generation and supply of electricity, and (so far as consistent therewith) facilitating such competition in the sale, distribution and purchase of electricity.

2. 5 Fundamental Questions - Criteria for assessment of Consistency of Candidate Models

- a. How should rights be defined?
- b. Who buys and sells and trades those rights?
- c. What are the consequences of breaching those rights?
- d. Who are the players and what are their contractual relationships?
- e. How should NGC's investment decisions be driven, in relation to cost recovery or investment costs?

3. Ofgem's Expectations of Transmission Access:

Ofgem document 'R19/02 Transmission Access & Losses under NETA – Revised Proposals' 26/2/2. Para 4.26

4.26 Ofgem considers that there are a number of key elements to any transmission access regime. These are as follows:

- Firmness: once allocated, access rights can only be interrupted by the SO buying back the rights. Equally, participants who have been allocated rights will be committed to paying for them for the length of time for which they have been allocated.
- Duration: it would be desirable for access rights to be allocated for several years at a time in order to ensure that signals of the need for new transmission capacity can emerge.
- Trading: for market signals to emerge, some form of trading will be necessary. Tenders for constraint contracts would be one such form of trading but it would be desirable for participants also to be able to trade between themselves.
- Cost signaling: to inform participants' trading decisions, it will be important that they are exposed to the locational costs that NGC incurs in resolving constraints.
- Linkage to SO incentives on investments: the access regime should enable the SO to be incentivised to respond to market signals of the need either for new transmission capacity in excess of that agreed as part of the TO price control or for intended investments to be delayed.

Appendix B: *TASG Terms of Reference and Membership*

Appendix C: *Group Process outline of meeting schedule and reports to CUSC Panel*