nationalgrid

CONSULTATION DOCUMENT VOLUME 1

CUSC Amendment Proposal CAP166

Transmission Access
Long Term Entry Capacity Auctions

The purpose of this document is to consult on Amendment Proposal CAP166 with CUSC Parties and other interested Industry members

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Responses to this consultation should be sent to bali.virk@uk.ngrid.com by close of business on 23 February 2009. Respondents are requested to include the term 'CAP166' in the email subject line.

I DOCUMENT CONTROL

a National Grid Document Control

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1.0	09/02/09	National Grid	Report for Industry Consultation

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The Gas and Electricity Markets Authority	Ofgem
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1.0 SUMMARY AND RECOMMENDATIONS

Executive Summary

1.1 CAP166, Transmission Access – Long-term Entry Capacity Auctions, was proposed by National Grid and submitted to the CUSC Amendments Panel for consideration at their meeting on 25 April 2008. CAP166 proposes that all long-term entry access rights to the GB transmission system would be allocated by auction.

1.2 The CAP166 original proposal includes the following main features for access to the wider transmission system:

- Long-term entry access would be released annually in blocks of whole financial years;
- Long-term entry access rights would be defined on a zonal basis, such that each User can share capacity between its power stations on a real time basis at a 1:1 exchange rate within these defined zones;
- Capacity would be allocated on a pay as bid basis up to a zonal baseline;
- The User commitment associated with long-term entry access rights would be a liability to pay the accepted bids, with the associated security arrangements to be developed by the Working Group in accordance with the Best Practice Guidelines for Gas and Electricity Network Operator Credit Cover.
- Outside of a specified period an incremental capacity release methodology would be developed to release capacity above the baseline to bids meeting a regulatory test.

1.3 The CAP166 original proposal also includes separate arrangements for infrastructure comprising generators' local connections, including the appropriate User commitment (which may be approximately equivalent to 100% of costs).

1.4 Following consideration of CAP166 by the Working Group, three Working Group Alternative Amendments were agreed.

Working Group Alternative 1 (WGAA1)

WGAA1 was proposed by National Grid and features an auction based upon a boundary constraint model where access is auction on a nodal basis (rather than the zonal basis in the original amendment proposal). WGAA1 allows the auction to determine the price of such access, with there being no set reserve price.

Working Group Alternative 2 (WGAA2)

WGAA2 was also proposed by National Grid, and again features an auction based on a boundary constraint model. WGAA2 was developed following a Working Group Consultation Alternative Request and introduces the concept of a reserve price that is reflective of both the Long Run Marginal Costs of providing existing and incremental capacity and also the Short Run Marginal Costs of allowing an over-allocation of capacity across derogated system boundaries.

Working Group Alternative 3 (WGAA3)

WGAA3 was initially proposed by Bill Reed, a Working Group member, prior to the Working Group consultation but due to the lack of time was not developed any further from the initial proposal. However upon the granting of a time extension for the Working Group it was more fully developed into the Working Group Alternative Amendment described in this Working Group Report. It features a Capacity-Duration Auction where access is allocated to all those that request it in a given year with the costs of providing such access being split into two charges; a long-run priced element which is designed to reflect the existing TNUoS charges for the costs of transmission infrastructure and a short-run priced element which reflects the forecast operational costs (in the form of transmission constraints) of providing access to a User in advance of any necessary transmission reinforcements being completed.

1.5 The Working Group was unable to develop all of the options fully under the original timescales. Instead, it focused its effort on developing WGAA1 and following the Working Group consultation, WGAA2 as it is largely similar to WGAA1. WGAA2 was proposed by National Grid during the Working Group consultation (WGCR02) due to concerns about revenue recovery in WGAA1. WGAA1 and WGAA2 propose the allocation of rights to individual nodes, rather than at the zonal level, with a boundary constraint model that clears simultaneously across the entire network. In essence bids are accepted so as to maximise total auction revenue, but subject to ensuring that limits on flows across pre defined boundaries are not breached. In effect generators compete in the auction with other generators who are subject to the same constrained boundary or boundaries as them. As these boundary constraints can interact with each other, this calculation is carried out simultaneously through linear programming. Following the granting of a time extension to the Working Group, WGAA3 was also further developed.

1.6 Four further proposals were put forward for consideration as candidates for Working Group Alternative Amendments, one by a Working Group member during the initial assessment of CAP166 (denoted as WGAA2 in the Working Group Consultation issued on 17 October) and three others by respondents to the Working Group Consultation. Due to the time available to Working Group 2 to assess these alternative proposals all four were unable to be fully assessed as whether they were suitable to move forward as formal Working Group Alternatives. A record of each is included within this report. However, the Working Group requested an extension to further develop proposals for a capacity and duration auction model. This extension was granted and through discussions on this proposal WGAA3 and WGAP1 were developed.

1.7 A record of the three Working Group Consultation Requests that were not taken forward (WGCR01, WGCR03, and WGCR04) is outlined in section 13.0.

1.8 A record of the Working Group Alternative Proposal (WGAP1) is included in section 4.3.

1.9 For WGAA1 and WGAA2, boundaries have been defined to provide an appropriate balance between the accuracy of the model and its simplicity so that bidders are able to participate effectively. Generators will be cleared at the same price if they are subject to the same critical boundary. There are likely to be a number of different cleared prices across the network.

1.10 A basic spreadsheet model has been developed to test the approach proposed for WGAA1 and WGAA2. Whilst there has been very limited time to carry out such analysis, early indications are that the model is capable of allocating transmission capacity to generators in the manner intended. However, this has not been rigorously tested.

1.11 It appears that the charges that generators would see under an auction with no reserve price would be very different from those produced by the present TNUoS charging methodology. This is because the present methodology calculates charges on the basis of the modelled flows that generators cause across the transmission system and the cost of transmission system to accommodate those flows, whereas the auction reflects the scarcity of capacity behind a constrained boundary.

1.12 Issue 1.0 of the Working Group Report was submitted to an extraordinary CUSC Panel meeting on 5th December 2008. The Panel allowed an eight week extension to further consider a capacity and duration auction model. Following this extension, version 2.0 of the Working Group Report was submitted to the CUSC Panel meeting on 30th January 2009. The Panel agreed that a Consultation Report containing the CAP166 original proposal, WGAA1, WGAA2 and WGAA3 should proceed to wider industry consultation as soon as possible, that the Working Group Report be accepted and that the Working Group be disbanded.

Working Group Recommendation

1.13 The Working Group voted on whether they believed the original or the Working Group alternatives are **better than the current baseline**. The result of the vote is described in the following table:

Proposal	Better	Not better	Abstained
Original	0	13	0
WGAA1	0	13	0
WGAA2	2	11	0
WGAA3	2	11	0

1.14 Next the Working Group voted on whether they believed the original or the Working Group alternatives are **better than the original amendment**. The result of the vote is described in the following table:

Proposal	Better	Not better	Abstained
Original	-	-	-
WGAA1	1	8	4
WGAA2	3	6	4
WGAA3	4	8	1

1.15 The majority of the Working Group believed WGAA1 and WGAA2 were not better than the original or the baseline. The Chair of the Working Group with support of some members of the Working Group took forward WGAA1 and WGAA2.

1.16 The Working Group voted on which of the proposals they believe best facilitates the applicable CUSC Objectives. The result of this vote is described in the following table:

Proposal	Best
Original	0
WGAA1	0
WGAA2	2
Abstained	11

1.17 After the Working Group extension the Working Group voted again on which of the proposals they believe best facilitates the applicable CUSC Objectives. The result of this vote is described in the following table:

Proposal	Best
Original	0
WGAA1	0
WGAA2	0
WGAA3	3
Abstained	10

2.0 PURPOSE AND INTRODUCTION

2.1 This is a consultation document issued by National Grid under the rules and procedures specified in the Connection and Use of System Code (CUSC) as designated by the Secretary of State.

2.2 Further to the submission of Amendment Proposal CAP166 and the subsequent evaluation by Transmission Access Working Group 2, this document seeks views from industry members relating to the Amendment Proposal and the three Working Group Alternative Amendments.

2.3 This consultation document also outlines the discussions held by the Working Group, the responses to the Working Group Consultation and the nature of the CUSC changes that are proposed. Representations received in response to this consultation document will be included in National Grid's Amendment Report that will be furnished to the Authority for their decision.

The Transmission Access Review Working Groups

2.4 CAP166 was proposed by National Grid and submitted to the Amendments Panel for their consideration on 25th April 2008.

2.5 In a change from normal practice, CAP166 was one of six Amendment Proposals which the CUSC Amendments Panel divided between two Working Groups under the banner of the Transmission Access Review. Working Group 1 has considered CAPs 161-164 and Working Group 2 CAPs 165 and 166. The Panel also directed the formation of a third Working Group (known as "Working Group 3") to assess some enabling changes which underpin a number of these CAPs related to transmission charging proposals under the Transmission Charging Methodologies Forum (TCMF).

2.6 A combination of two, or more of these six CAPs collectively or, potentially in the case of Connect and Manage, individually, could be considered to constitute a model of transmission access reform. At the time of the original six proposals there were broadly speaking three models: (i) Connect and Manage (CAP164); (ii) Evolutionary Change (CAPs 161, 162, 163 and 165); and (iii) Evolutionary Change with auctions (CAPs 161, 162, 163 and 166). However, the intention is that all six CAPs can be implemented individually or in certain combinations with each other.

2.7 The Working Groups have also been constituted to deliberate on related transmission charging proposals under the Transmission Charging Methodologies Forum (TCMF). This consultation is concerned with the CUSC-related issues of CAP166, although references are made to charging where this aids understanding of the proposed Amendment. Charging issues are being consulted on in a parallel pre-consultation.

2.8 The Amendments Panel agreed that Working Group 2 would work towards submitting a report on CAP166 back to the CUSC Panel within 3 months, inclusive of a period of Working Group Consultation. An extension of 2 months to this timetable was granted by the CUSC Panel on 25 July 2008 after a request from the Chair of Working Group 2. A further extension of 2 weeks was granted by the CUSC Panel on 3 October 2008.

2.9 Following this two week extension a Working Group report was presented to the CUSC Panel on 5th December 2008. It was noted that within this report one option, that of a "Capacity-Duration" auction model had been initially drawn up, but due to the available timescales not fully developed. In order that this model be more fully investigated and noting the Authority's desire to be able to consider the fullest range of options available to it for CAP166 the CUSC Panel granted the Working Group a further 8 weeks in which to consider the Capacity-Duration auction model.

2.10 Furthermore, the Authority's approval of CAP 160 during the assessment period alters the way in which the Working Group considers Alternatives raised in the consultation process.

2.11 Working Group 2 considered the issues raised by CAP166 and considered whether the amendment proposal, and some suggestions for potential Working Group Alternatives, better facilitated the Applicable CUSC Objectives as compared with the current version of the CUSC. Working Group 2 met 30 times during the assessment period for CAP166 and attendance is recorded for voting purposes in Annex 6. Each Working Group meeting was attended by CUSC Party-nominated members or their alternates, and invited experts. Working Group 2 also drew on discussion in Working Group 3 mainly regarding the definition of local works.

2.12 Section 3 of this Consultation Document describes the original proposed amendment. Section 4 summarises the Working Group discussions and section 5 presents three Alternative Amendments developed by the Working Group. Section 6 considers the original amendment proposal together with the Working Group Alternative Amendments against the applicable CUSC objectives.

2.13 The CAP166 Working Group Report was submitted for the second time to the CUSC Amendments Panel meeting on 30 January 2009. Following evaluation and consultation by the Working Group, the Amendments Panel determined that CAP166 was appropriate to proceed to wider industry consultation by National Grid.

2.14 Representations received in response to this Consultation Document will be included in National Grid's Amendment Report that will be sent to the Authority for their decision.

2.15 This Consultation Document has been prepared in accordance with the terms of the CUSC. An electronic copy can be found on the National Grid Website, www.nationalgrid.com/uk/Electricity/Codes/, along with the Working Group Report and the Amendment Proposal form. This document invites views upon CAP166. The **closing date for such responses is 23rd February 2009** This Report summarises the deliberations of the Working Group, describes the Original CAP166 Amendment Proposal as well as the Working Group Alternatives and details the responses to the Working Group Consultation.

2.16 Comparison with Current Methodology

2.16.1 The following table provides a summary of the comparison between the current methodology and that under an auction framework:

Options	Current Methodology (TNUoS)	Auction Framework	
		Price Based Auction	**Capacity / Duration Auction**
Nature of rights (Local)	Enduring	Enduring	Enduring
Nature of rights (wider)	Enduring	Finite	Finite
Capacity definition	TEC in Bilateral Connection Agreement (BCA)	Local Capacity Nomination (LCN) and Transmission Access Capacity (TAC) in BCA	Local Capacity Nomination (LCN) and Transmission Access Capacity (TAC) in BCA
Revenue Recovery (Pricing)	LRMC with residual pricing (TNUoS)	Cleared price through auction with residual pricing	Long-Run Marginal Costs for access provided through physical transmission assets. Short-Run Marginal Costs for access provided through operational actions Residual pricing
Allocation of rights to wider system	First come first served	Price driven	Equal basis among all parties in auction
Volume of long-term rights	Determined by SQSS	Determined by SQSS (with separate arrangements for derogated boundaries)	As requested by User in auction

2.16.2 This Working Group Report has been prepared in accordance with the Terms of the CUSC. An electronic copy can be found on the National Grid Website, www.nationalgrid.com/uk/Electricity/Codes/, along with the Amendment Proposal Form. A copy of each of the Working Group Consultation responses is contained in Working Group Report Volume 2 on the National Grid Website, www.nationalgrid.com/uk/Electricity/Codes/ .

3.0 PROPOSED AMENDMENT

3.1 This section describes National Grid's original CAP166 amendment proposal and includes clarifications that have resulted from Working Group discussions. The full text of the original amendment proposal can be found in Annex 7.

3.2 Defect

3.2.1 This CAP166 amendment proposal seeks to address a number of defects which, in the view of the proposer of CAP166, exist with the current transmission access arrangements.

3.2.2 The current entry access arrangements give existing generators a rolling option to renew their rights to access the transmission system on an annual basis. The allocation of these rights is through incumbency, so that, when there is no spare capacity and where there is a time-lag in the provision of new capacity, new Users have no ability to obtain from National Grid acting as the Great Britain System Operator (GBSO) long-term transmission access rights even if they would value them more highly than incumbents.

3.2.3 The fact that the true value of transmission access rights cannot be discovered from the market compromises transmission licensees' ability to develop an optimally economical system of electricity transmission, as well as creating a barrier to entry. Entry could be facilitated by improving liquidity in the trading of transmission access rights (and separate amendments have been proposed to do so), but in order for Users that are able to trade capacity to do so at value they first should have had to pay value for those rights.

3.2.4 The proposed amendment also seeks to address the issue that the current arrangements, whereby generators have a rolling option, do not provide any certainty to National Grid and Transmission Owners. This uncertainty can lead to inefficient transmission investment signals, in that the planning of incremental capacity can take little, if any, account of the potential future release of existing capacity currently held by incumbents. Additionally, existing generators are not required to put in place any financial security, even for the one year's worth of charges they currently incur a liability for.

3.3 Principles

3.3.1 This CAP166 original amendment proposal seeks to allocate all long-term entry access rights to the electricity transmission system by auction. All existing transmission access rights (both for existing pre- and post-commissioning power stations) would be withdrawn and reallocated using this new process. All power stations operating at, or due to commission after, the implementation of CAP166 would no longer have any access rights to the wider transmission system from this time if they had not obtained them in the proposed CAP166 auction.

3.3.2 All the available transmission access rights across the GB transmission system would be identified on a zonal basis, and released in annual (financial year) blocks. Auctions would be held annually, and long term transmission access rights allocated on a pay as bid basis to the limit of the available ("baseline") zonal capacity.

3.3.3 There would be a reserve price based on the current Transmission Network Use of System (TNUoS) Charging Methodology.

3.3.4 Successful bookings would be underpinned by User commitment in the form of a liability to pay the accepted bids for the duration of their access booking. Financial security for such liabilities would be required.

3.3.5 Outside of a specified period, incremental capacity would be released by the GBSO where any unfulfilled bids in excess of the zonal reserve price were of a level sufficient to pass a regulatory test, which would need to be defined under a separate Incremental Entry Capacity Release ("IECR") methodology.

3.3.6 These arrangements would provide access to the wider transmission system. Separate arrangements would be put in place for infrastructure comprising generators' local connections to the wider transmission system, such that potential new generators would first apply for a local connection, and would then have their generators' bids for long-term entry access rights constrained to the sum of their prevailing contracted or offered local capacity limits in the zone in which they were connecting. Separate arrangements for charging and security would apply for local infrastructure, and for the residual element of the entry Transmission Network Use of System ("TNUoS") capacity charge.

3.3.7 For the avoidance of doubt, no capacity allocated to a User in one auction would be removed or reallocated from that User in any subsequent auction, even if the bid price for that capacity is greater in the second auction compared to the first.

3.4 Process

3.4.1 The high-level process approximately splits into two elements

- The allocation of local access rights
- The allocation of wider access rights

3.4.2 A flow-chart that details the high level process and is complementary to the rest of this section 3.4 is attached at Annex 2.

3.4.3 The allocation of local access rights is dependent on the introduction of a parameter to define a User's local access rights – the Local Capacity Nomination (LCN).

3.4.4 The Local Capacity Nomination (LCN) would be the maximum capacity (in MW) to which a generator is entitled to obtain transmission access products (long-term and short-term access products including overrun) within an auction year (equivalent to National Grid's current charging year – April to March). It must not exceed the Connection Entry Capacity (CEC) of the generator to avoid damage to the local transmission assets.

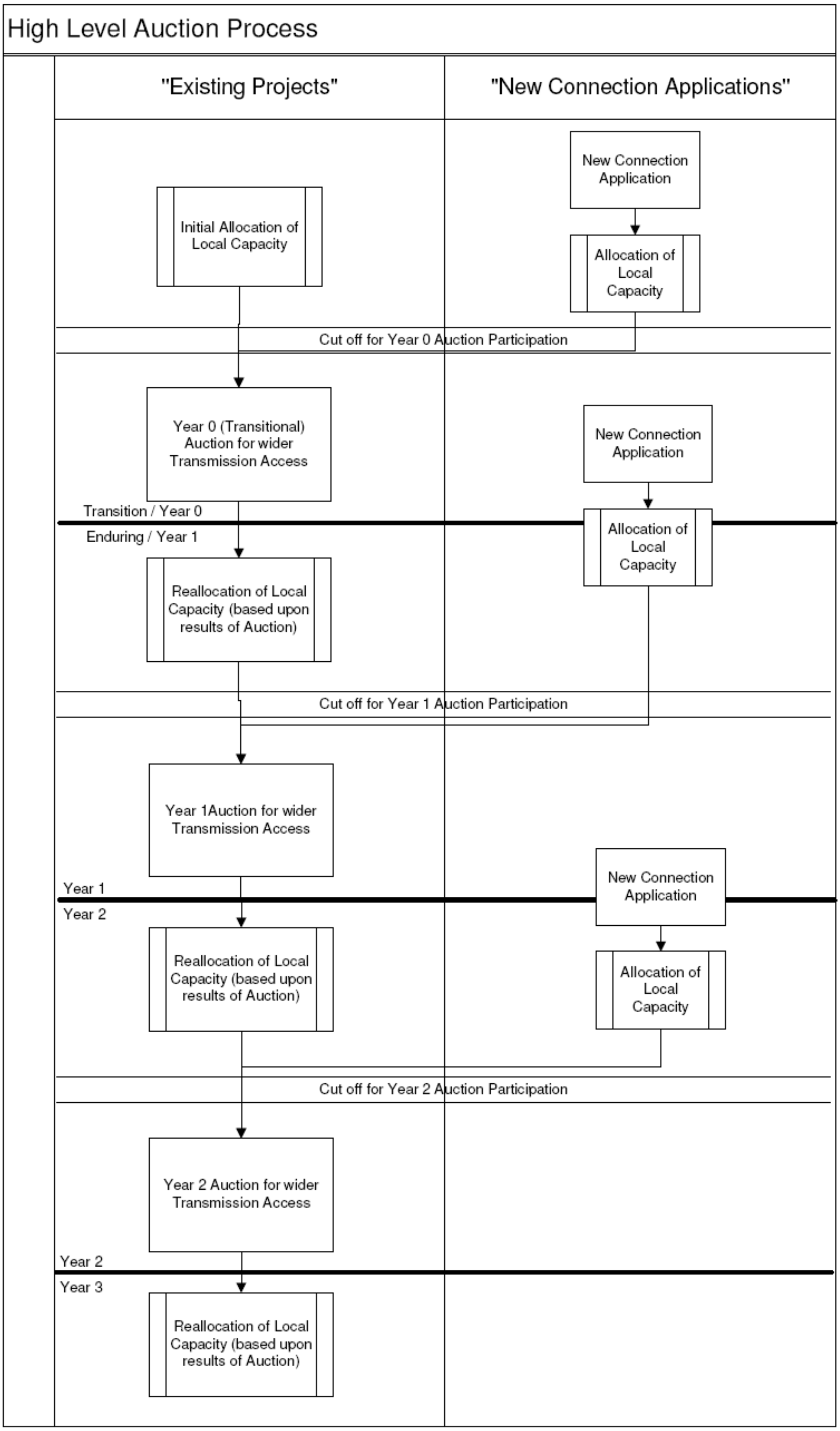
3.4.5 LCN will be the basis upon which a generators' local TNUoS charge will be calculated and levied.

3.4.6 LCN could be shareable between generators, when multiple generators agree to share. Any sharing arrangement would be managed with a clause which, in the case of two generators sharing, would restrict one generator if the other generator is using the local connection capacity and vice versa. This approach is similar to that currently adopted to deal with design variation connections.

3.4.7 The concept of LCN will be introduced into CUSC Exhibit B: Connection Application. A local connection application will be progressed under the same process as an existing local and wider connection application.

3.4.8 The manner in which allocation of local and wider access rights interact is as shown in Figure 1 below:

Figure 1: Proposed High Level Auction process



3.4.9 Allocation of Local Access Rights

3.4.9.1 It is clear from the above that there is a significant interaction with the assessment of local works required to deliver the User's requested level of local access and the wider works allocated through the proposed auction The management of this interaction has been a key discussion point of the Working Group (see sections 4.3 and 4.4 for further details).

3.4.9.2 The high level process would commence with an allocation of local access rights to existing Users[1]. The level of local access rights granted to a User would be denoted by its Local Capacity Nomination (LCN); the LCN would form the upper limit on the combined wider capacity a User may procure through any auction or short-term access products (including overrun). An LCN would consist of a MW level and a date from which that MW level is applicable. Staged projects might see a ramp up of LCN as the project is progressively completed.

3.4.9.3 The default LCN value granted to an existing User would be the TEC level granted in its Bilateral Agreement. For those projects yet to commission / energise the effective date will by default commence at the same time the TEC value was due to come into effect (as specified in the BCA) and will carry the same MW level as the existing TEC value.

3.4.9.4 Once the stages above have been completed for existing Users then so the enduring process will come into effect for any existing Users that wish to explore a change in their local access rights. Each User that wishes to change the timing or level (MW) of their LCN from its default TEC value will signal this intent to National Grid (this may be through a Modification Application or some other transitional process to be defined). Similarly the following process will be followed by any new Users applying to connect a Power Station to the GB Transmission System.

3.4.9.5 National Grid will for each connection application (or transitional) request calculate two dates the "earliest LCN date" and the "backstop LCN date". The "earliest LCN date" is the earliest date by which works to deliver the desired LCN capacity could be completed (assuming they were commenced from the beginning of the next financial year and if that project was considered in isolation). The "back-stop LCN date" is calculated using a similar process but considers the earliest date by which all projects that wish to advance their LCN can have the works delivered to do so. It is clear that in all cases the "earliest LCN date" <= "back-stop LCN date".

3.4.9.6 Any projects that wish to increase their LCN MW level will also have an assessment of whether there are any additional local works necessary to accommodate this and if so this may impact upon one or both of the offered "earliest LCN date" and "back-stop LCN date". Both the notified (offered) "earliest LCN date" and "back-stop LCN date" will be conditional in two areas:

- The results of the next wider access auction; and,

[1] The Term "existing Users" denotes any User that has a signed Bilateral Connection Agreement or Bilateral Embedded Generation Agreement by a certain "transition date"

- Applications from other Users ("subsequent User(s)") to connect in the same locality as the "first User" which are received after the "first User" has received its offer and which are signed by the "subsequent User(s)" before the cut-off date for the next wider access auction.

3.4.9.7 Regarding the conditionality with the results of the wider access auction, a User will only have its final LCN Effective Date firmed up once it is known whether it has secured wider access in that auction. Those Users that are successful in the wider access auction will then receive a firm LCN effective date that aligns with their booked wider access rights. Those parties that fail to secure wider access rights in the auction will then be offered their "back-stop LCN date" as their firm LCN Effective date.

3.4.9.8 The conditionality in advance of the auction would work along the following lines. The first User to apply to connect in a locality may receive a "Earliest LCN Date" and a "Back-Stop LCN Date" that are the same and equal to the date to facilitate only that User's Power Station. Then a second User applies to connect in the same locality. The second set of local works to facilitate the LCN is more complex than the first Users so the second User is offered an "Earliest LCN Date" equivalent to that offered to the first User, but its Back-Stop LCN Date is further into the future reflecting the more complex works to connect two Power Stations in the same locality. The first User must then also have its Back-Stop LCN date amended to be consistent with the first User.

3.4.9.9 In the above example the capacity constraints to deliver the local works for the two Power Stations will be reflected in the incremental capacity supply curves that feed into the auction process. This will ensure that only one of the two generators in the locality (in the above example) will be able to procure wider auction access in timescales consistent with their Earliest LCN Date. The other will then only be able to procure access consistently with the Back-Stop LCN Date.

3.4.9.10 It should be noted that in situations in which the provision of local capacity is constrained, these arrangements prioritise the provision of local capacity based on the outcome of the auction for wider long-term transmission access rights. By the end of the above process the "queue" for local works would have effectively been optimised based upon the desire of the User to commit to wider long-term transmission access.

3.4.9.11 In circumstances in which local capacity is constrained and priority is given to those Users that are successful in the auction, but some local capacity remains available, this would be allocated on a first-come-first-served approach (similar to that currently adopted for interactive offers).

3.4.10 Allocation of Wider Access Rights

3.4.10.1 The auction process, under CAP166, would give Users the opportunity to bid for long-term transmission access rights which provide the (generator) holder with a (perfect) hedge against the short-term value of transmission access (i.e. Users that operate within the (MW) volume of transmission access rights they purchase in the auction are not exposed to the short-term cost of transmission access).

3.4.10.2 The auction process proposed under the Original Amendment would have the following key attributes:

- A zonal, dynamic, cleared price, multi-year auction as more fully described in section 4 below.
- The auction will allocate capacity for a 40 year period i.e. the 2010 auction (run in autumn 2010) would allocate capacity from April 2011 to March 2051.
- All 40 annual allocations would run simultaneously in the auction. The methodology used for each of the years that are covered by the auction is summarised below:
    - Establish physical zones and associated capacity limits based on SQSS security criteria
    - Establish demand at system peak in each zone
    - Establish the supply function for incremental transmission capacity for each zone for each year
    - Enhance the boundary capabilities associated with derogated boundaries, e.g. England-Scotland boundary (SYS boundary B6) increased to accommodate derogation associated with BETTA transition arrangements
    - Publish market information covering zones and incremental capacity (supply function).
    - Invite bids for capacity in each zone for each of the years on a volume and price basis – Generators would be limited to a maximum number of Bids per Power Station equal to 5 × (Number of BMUs at the Power Station).
    - Generators would also be able to set a “de-minimis” auction acceptance volume parameter that would limit the auction model from accepting a Bid from a Power Station if it was pro-rated or capped at a level below the de-minimis value specified.
    - There will be a reserve price set in each zone equal to the zonal generation TNUoS tariff calculated in accordance with the existing ICRP model.
    - Run the zonal auction to maximise notional value indicated by bids whilst ensuring that the flows across each boundary is not exceeded.
    - Set the cleared prices based on accepted bids in each zone
    - Publish results to the market and allow for revision of bid price and volume with a reduction in volume being only reversible if another party subsequently reduces volume within the same zone
    - A number of rounds would then ensue with the ability for auction participants to revise bid prices and volumes in each round. This process would continue until no further material movement takes place between three successive rounds of the auction. A contingency for a forced close by only allowing upward price and volume movements will be in place after [15] flexible auction rounds have taken place.
    - The rounds would occur on each working day in September and October. Bids would be accepted from Users between 08:00 – 17:00 on each working day with the results of that round being published by 20:00 on the same day. The exception would be the first two rounds of the auction held in each year which would occur on the first and third working days of September. The extra day being to allow Users to fully appraise the results of the first round and further refine their bidding strategy.

- Capacity will be allocated based on auction result with fixed financial commitment based on the zonal cleared price for each year.

3.4.10.3 The maximum (MW) volume of long-term transmission access released by the GBSO would be based on the amount of existing TEC (be that from commissioned generators or from pre-commissioning generators). In zones with spare transmission access capacity, this (MW) volume would be increased on a pro-rated basis across all such zones until the SQSS would be breached. This means that Users would be able to operate their power station either using the short-term transmission access regime introduced by CAP161 (SO Release of short-term access rights), CAP162 (entry Overrun) and CAP163 (entry access right Sharing) (in the event of the approval of these amendments) or obtain a hedge against this by bidding for long-term transmission access rights in the auction. If Users were to bid for long-term transmission access rights only when the (cost-reflective) short-term price is higher, and the Transmission Licensees construct transmission assets in order to release these long-term rights then this should result in an economic and efficient transmission network.

3.4.10.4 From the perspective of different types of Users, the wider access auction process proposed by CAP166 would have the following implications:

<u>Existing (post-commissioning) User</u>

3.4.10.5 The proposed arrangements would replace the existing rights and obligations under the CUSC with regard to transmission access rights and charging liabilities. Existing Users would be required to bid for the long-term access rights alongside Users that wish to use the system in the future.

3.4.10.6 The auction would be held once a year in September for long-term access rights starting from the following 1 April.

3.4.10.7 Prior to the commencement of the auction, the GBSO would publish the following information:

- Zonal baseline transmission capacities (in MW);
- Previously sold baseline capacities (in MW);
- Local Capacity Nominations (LCNs) (in MW)
- Reserve prices (in £/MW); and
- Details of the Incremental Entry Capacity Release methodology.

3.4.10.8 Users would bid in each of the future (whole financial) years that they want long-term transmission access rights with the associated capacity (in MW) and price (in £/MW/year). Users would be able to bid for different capacities and with different prices in each year.

3.4.10.9 In the first round of the auction, bidding may be difficult since successful bidding involves accurately forecasting the clearing price, however, at the end of the first round, the GBSO will publish the following information:

- Long-term transmission access right allocations in each year (MW in each zone);

- Details of the 'hurdle' test for incremental capacity release, including the level of incremental capacity triggered in each future year.

3.4.10.10 Bidders then have an opportunity to make use of this information and revise their bids in a series of future rounds.

3.4.10.11 Further auction rounds would take place until the changes in the transmission access allocation between two successive rounds fall below the pre-defined tolerance level (in MW). The auction would then close.

3.4.10.12 Users that are successful in the auction would then receive the long-term transmission access rights (which provide a hedge against the short-term cost of transmission access) for the capacity (in MW) for which they were successful in the years in which they were successful.

3.4.10.13 Users would also be committed to paying the associated price they bid (£/MW/year) for these long-term access rights in the years in which they were successful.

3.4.10.14 If Users trigger incremental capacity and this is not provided by the TOs, the GBSO will be required to buy back the capacity that cannot be provided.

3.4.10.15 Users that are unsuccessful in the auction could make use of the short-term transmission access regime, or wait until the next auction for long-term transmission access rights.

3.4.10.16 All generation Users (those utilising short-term access rights and long-term access rights) will be required to pay use of system charges which will be set to recover any difference (surplus or deficit) between the auction revenue and the proportion of the transmission licensees maximum allowed revenue to be recovered from generation Users (27%).

New (pre-commissioning) User

3.4.10.17 New Users would bid for long-term access rights in the auction alongside existing Users. The auction process would be as set out above for existing Users.

3.4.10.18 New (pre-commissioning) Users will need a connection to the transmission system in order to make use of long-term transmission access rights. New Users will be able to apply for local (MW) capacity via a local connection with the offer remaining open until the auction of wider long-term transmission access rights is concluded.

3.4.11 Auction Timescales

3.4.11.1 It is envisaged that each annual auction would commence on 1st September in each year and would likely endure for no longer than 2 calendar months.

3.4.11.2 Users who wish to participate in a given year's auction should ensure that they have a signed offer for local connection by 1st June in the same year (although dispensations may be available for Users who have referred their offer for connection to the Authority). Further details on timescales may be found in section 4.4 below.

3.4.12 Wider Access Capacity Baselines

3.4.12.1 The baseline capacity to be auctioned in each wider access auction will be set equal to a capacity made up of the following components:

- Firstly the capacity that would be released within each zone under a strict interpretation of the GB SQSS planning criteria[2] will be assessed;
- Secondly for the first year of the auction process any zones that have "existing TEC allocations" in excess of that permitted through a strict application of the GB SQSS (known as "over-allocated zones") will have this level of baseline auction capacity applied for the first annual auction only. The "existing TEC allocation" in a zone will be set equal to the sum of the TEC of generators already connected to or using the GB Transmission System in that zone (i.e. commissioned and generating) and the TEC of generators that will connect to or use the GB Transmission System in the first year for which long-term capacity rights will be granted via auction.
- Finally any other derogations which permit the allocation of explicit additional baseline capacity in a zone will also be accounted for and the explicitly stated volume in any such derogation will be added to the baseline.

3.4.12.2 Once the results of the first annual auction are known future baseline allocations will be as follows:

- In non "over-allocated zones" the baseline auctioned will continue to be based upon that permitted by the GB SQSS Planning Standards;
- In "over-allocated zones" the baseline auctioned from year 2 onwards will be equal to that purchased by Users in year 1 plus any incremental capacity that may be physically constructed.

3.4.12.3 In future years, incremental physical capacity that can be offered to Users will be specified in the form of "incremental capacity supply functions" and will correspond to the completion of physical transmission system reinforcements. The incremental capacity supplied by such reinforcements will be applied to the auction from the next 1st April following the completion of the reinforcement.

3.4.13 Reserve Prices

3.4.13.1 In the CAP166 Original Amendment there will be a zonal reserve price set in the auction for Wider Transmission Access based on the current Transmission Network Use of System (TNUoS) Charging Methodology. The TNUoS charging zones would be redrawn to be consistent with the auction zones.

[2] NB. The GB SQSS is currently undergoing a substantive review. Should the Planning Standards be amended such that a different baseline capacity in a zone could be released into the long-term auction it would be the intention for this revised baseline capacity to be used.

3.5 Securities

3.5.1 Pre Commissioning Securities

3.5.1.1 Under CAP166 it is proposed that pre commissioning securities are comprised of security for local TNUoS charges only. Termination or reduction of the requested LCN would therefore result in the levying of a Local Capacity Reduction Charge, based on Local Cancellation Amounts. The Local Capacity Reduction Charge would be non-refundable.

3.5.1.2 The Local Cancellation Amount in each year would be a percentage of the Local Termination Amount, which is the higher of zero and eight times the relevant local generation TNUoS charge. The Local Capacity Reduction Charge would therefore be calculated as:

Local Capacity Reduction Charge = LCN_r *x* $LCAM_t$

Where:

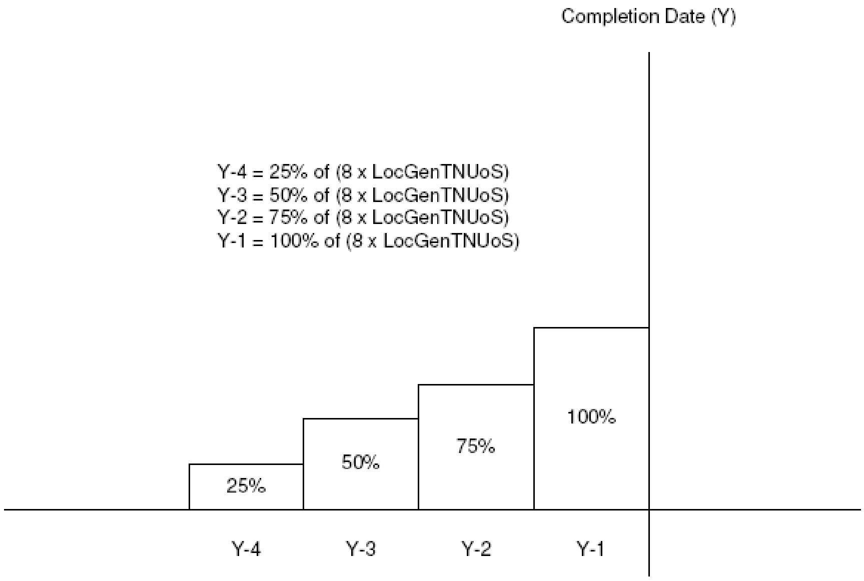
- LCN_r is the reduction in Local Capacity Nomination in kW.
- $LCAM_t$ is the relevant Local Cancellation Amount which varies according to the number of full years from the Completion Date:
  - In the year prior to the Completion Date (i.e. t) *LCAM = LTA x 100%)*, where LTA is the Local Termination Amount;
  - Where t=-1, *LCAM = LTA x 75%*;
  - Where t=-2, *LCAM = LTA x 50%*; and
  - Where t=-3, *LCAM = LTA x 25%*.

Local Termination Amount = Max (0, ($LocGenTNUoS_n$ *x X))*

Where:

- $LocGenTNUoS_n$ is the relevant nodal Local Generation TNUoS tariff applicable to the generation project and published in the Statement of use of System Charges. If such a nodal tariff is not currently published, then the appropriate tariff will be calculated by National Grid as part of the application process, in accordance with the Charging Methodology.
- *X* is a multiplier, initially taking the value 8, although it may be appropriate that this be amended in subsequent price control periods.

This is shown diagrammatically below:



3.5.1.3 The value of X has initially been allocated the value of 8 according to the rationale developed through the assessment of CAP165. The 8 years figure is derived from analysis of TNUoS tariffs against wider UCAs, which shows that, on average, the UCAs are 15 times the TNUoS tariffs. The 15 is halved to reflect a 50/50 risk sharing between generators and consumers. Consistency would imply that the same multiplier could also be used for local connections in the CAP166 proposal.

3.5.1.4 However, there is an additional rationale for 8 years being an appropriate multiplier: If local TNUoS was exactly reflective of capital costs, then a capital payment of 8 x annuitised TNUoS would cover 50% of the capital costs. This is because the TNUoS methodology converts capital sums by assuming a 50 year asset life and a 6.25% rate of return. Annual sums can be converted into a capital sum by multiplying by:

$$(1-(1+0.0625)^{-50})/0.0625 = 15.22$$

3.5.1.5 If the 50% risk sharing, consistent with the CAP165 treatment for wider access is applied, the result is a multiplier of 8.

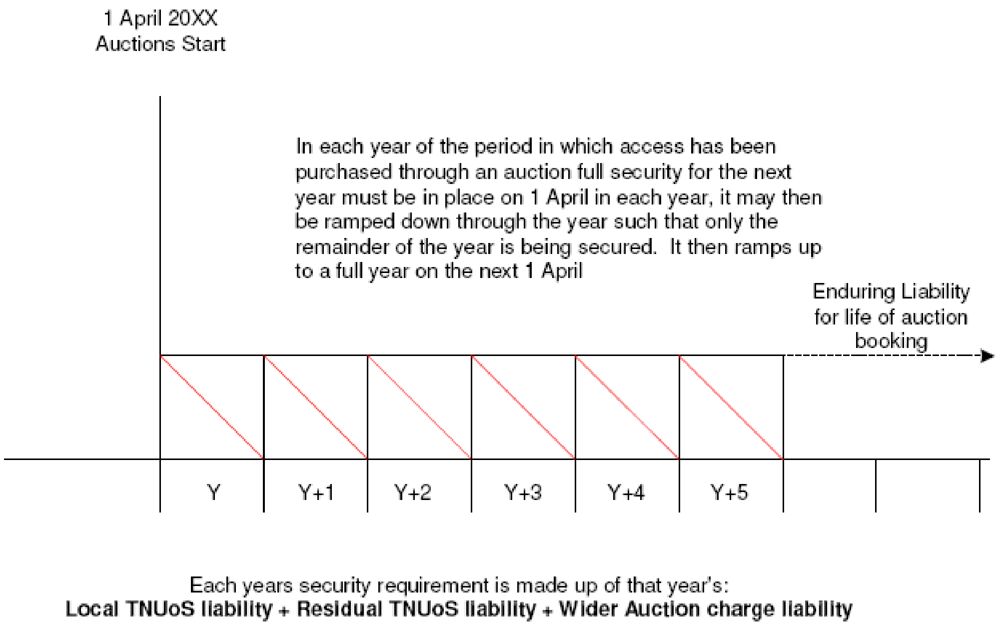
3.5.1.6 Local Cancellation Amounts will be calculated using the prevailing Local Generation TNUoS tariff at the time Capacity Reduction. Capacity Reduction Charges would not apply to projects where there are no transmission asset works.

3.5.1.7 The introduction of generic Local Capacity Reduction Charges, defined in the CUSC to replace the existing final sums regime, defined in the bilateral Construction Agreements, will also require the introduction of provisions to define the level of financial security that should be held in relation to these potential liabilities.

3.5.1.8 It is therefore proposed to add the applicable Local Cancellation Amount to each User's Security Requirement, as defined in paragraph 3.22 of the CUSC. To the extent that these amounts exceed the Allowed Credit extended to each User, Security Cover will need to be provided to National Grid, in any of the forms prescribed in the CUSC.

3.5.2 Post Commissioning Security

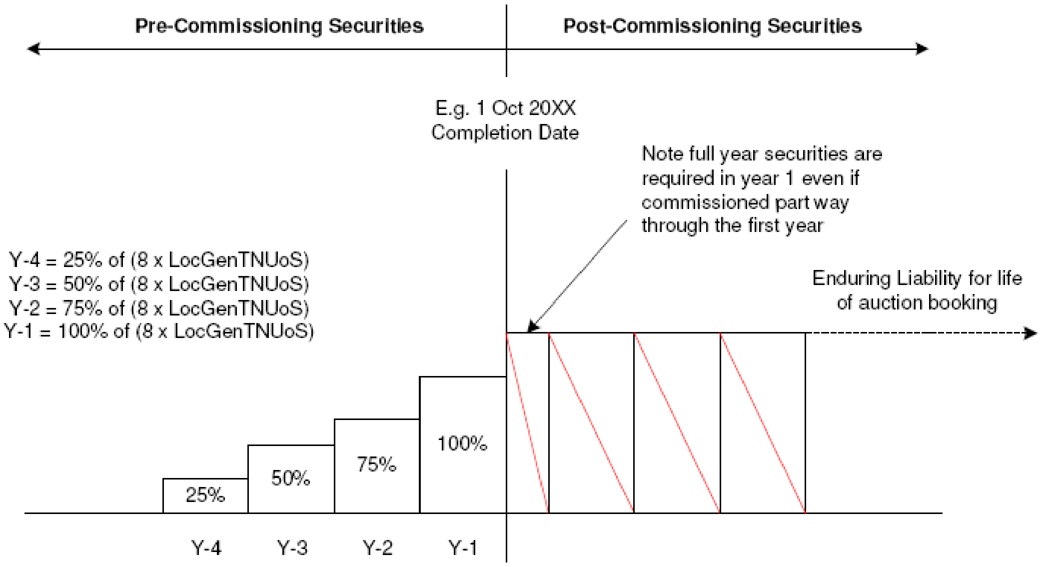
3.5.2.1 Financial security would be required for the balance of the current year's generation TNUoS charges – that is to say any Local TNUoS charge, Residual TNUoS charge and any charge payable based as a consequence of a successful auction bid. This amount would be added to each User's Security Requirement, as defined in paragraph 3.22 of the CUSC, and, to the extent these amounts exceed the Allowed Credit extended to each User, Security Cover will need to be provided to National Grid, in any of the forms prescribed in the CUSC. Diagrammatically this is as follows:



3.5.2.2 It is noted that should any of the component TNUoS charges be payable on a £/MWh basis, rather than a £/MW basis then there will need to be a year ahead forecast made to ensure the appropriate amount of security may be made available. This may be calculated as security for BSUoS is currently.

3.5.2.3 It is also noted that the above treatment of post-commissioning security would introduce a significant new requirement for security (27% of approx. £1billion of annual TNUoS revenues).

3.5.2.4 One other aspect of the post-commissioning security / charging arrangements for newly connecting generators is that a full years charges will be accrued and equivalent securities will be required even if the generator commissions part way through the year (as is the case with the existing TEC based charging arrangements). Diagrammatically the transition from pre- to post-commissioning securities is proposed to be as follows:



3.5.3 Security – Balance between Pre- and Post-Commissioning Generators

3.5.3.1 In the above it is noted that the proposed security requirements for post-commissioning securities as they stretch across Local, Residual and Wider TNUoS charges are more onerous than those for pre-commissioning securities which are based solely upon the Local element of TNUoS charges. This approach has been adopted in this proposal not because the Working Group believes that this is necessarily reflective of the actual risks posed by pre- and post-commissioning generators, but rather because the group has not been able to reach a workable proposal for charging equivalent securities for Wider and Residual TNUoS to pre-commissioning generators.

3.5.4 Transition to New Security Arrangements

3.5.4.1 As part of this process, there will be a reconciliation of the security requirements of Users from their existing levels of securities held under the current access arrangements to the new required levels of securities under any auction based access arrangements. Where a User wishes to retain its existing security arrangements (the “Pre-CAP166 Security Arrangements”) following any implementation of CAP166 then it shall be permitted to do so. This arrangement is in place due to the current financial climate and the concerns of certain generators that having to refinance securities due to a change of commercial regime may lead to material financial losses as the terms on which existing securities have been procured may no longer be available.

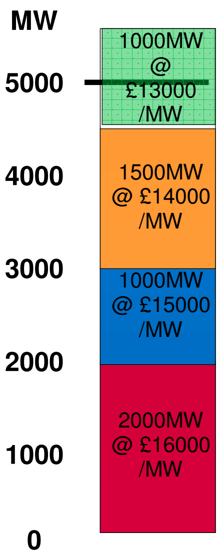
3.6 Auction Design

3.6.1 It is proposed that the auction for long-term entry capacity access rights would be on a pay as bid basis, with multiple rounds (of the auction). Generators’ bids would specify the volume (MW) of transmission access they required in each zone, and the associated price that they were prepared to pay.

3.6.2 In each zone, for each (whole) financial year (1st April to 31st March), the GBSO would stack the bids for transmission access capacity (MW) in descending price order. Bids would only be considered as valid if they were no less than a zonal reserve price (set by the GBSO and notified to bidders in advance). Bids in the stack below the zonal baseline (MW) capacity for transmission access would be allocated to the respective bidders. The marginal bid in each zone would be pro-rated to the limit of available (MW) capacity, and offered to the marginal bidder (with no obligation for them to take that capacity).

3.6.3 These rules are illustrated in the below diagram. The zonal baseline capacity in this example is 5000MW, and the reserve price is £13000/MW. Bids are stacked in descending price order such that the bid for 2000MW at £16000/MW is consider first. As can be seen, 4500MW is allocated to 3 Users. 500MW (of a 1000MW bid) is offered to a fourth User.

Example of a pay as bid auction for a given zone for a given year



3.6.4 In the event that there was more than one bidder at the margin (because all such bidders had bid the same price), the (MW) amount offered to each bidder would be pro-rated in proportion to the volume (MW) of each bidder's bid.

3.6.5 Negative bids would be permitted where the zonal reserve prices are negative. The most negative bids would be considered last (e.g. in a negative zone with three bids of -£1000, -£5000 and -£10000, the -£10000 bid would be considered last). Participation in the auction would be limited to physical players only (i.e. those with a local connection, or an offer for such in the years for which wider access rights were being bid) to prevent the price collapsing to zero.

3.6.6 Under CAP166, wider access rights would be explicitly de-linked from the local connection to the transmission system, and would be auctioned once a year. New entrants would need to apply for a connection to the transmission system at least 3 months before the annual auction to receive an offer for a local connection. This offer would be held open, by the GBSO, until the resolution of the auction process, and the User would have the option of accepting (or otherwise) the local connection offer dependent on the outcome of the auction (see section 3.10).

3.7 Incremental Capacity Release

3.7.1 Any unfulfilled bids (for transmission access) equal to, or in excess of, the zonal reserve price would be tested to see if the release of incremental capacity on the transmission system could be triggered.

3.7.2 A constrained period would be identified in which the release of incremental capacity could not be triggered (because the Transmission Licensees would not physically be able to deliver any reinforcements in such timescales). The exact period would be defined in the transmission licence, rather than the CUSC, and the CUSC would refer to this.

3.7.3 In each zone, the first year outside the constrained period would be considered, and the volume (MW) and price associated with any unfulfilled bids equal to, or in excess of, the zonal reserve price would be noted, and the resulting amount of revenue foregone calculated. It would be assumed that the total volume of such bids could be released, and the amount of additional revenue that could be derived from the release of unfulfilled bids in subsequent years would also be calculated. Where the Net Present Value of the resultant transmission revenue stream was in excess of 50% of the cost of providing the additional capacity, the incremental capacity would be released, and the reinforcement constructed.

3.8 Under/Over Recovery

3.8.1 The Working Group noted that the revenue recovered from successful auction bids was unlikely to equal the proportion of the transmission licensees maximum allowed revenue that is to be recovered from generation Users (27%). The Working Group discussed the provisions that would be needed to deal with over or under recovery. Whilst this is strictly a charging issue, the discussion is included here for completeness due to the interaction with auction.

3.8.2 The Working Group identified the following options to deal with any revenue surplus or deficit as a result of the auction.

3.8.3 Option A: Re-circulate to generation Users within the same zone

3.8.3.1 The Working Group investigated this option for the original CAP166 proposal. Given that a zonal auction is essentially a set of separate auctions for zonal capacity, the Working Group considered that the objective was to discover the differential between what bidders were willing to pay in a particular zone rather than between what bidders in different zones are willing to pay. For this reason, the Working Group considered that it may be appropriate for any zonal under or over recovery to be returned to Users that bid in that particular zone.

3.8.3.2 Following some basic testing of the original proposal, some Working Group members found that returning any over-recovery to Users within a particular zone meant that, for a dynamic auction, the auction would never close. Users within the zone would always be happy to increase their bid because they would know that their use of system charge (in this case payment) would also increase. For this reason this option has been discounted.

3.8.4 Option B: Re-circulate to all generation Users

3.8.4.1 The Working Group agreed that this would be the most appropriate approach for an ex post auction since it would ensure that the differentials between prices, which reflect the differences in the long-term locational value of transmission access, would be maintained.

3.8.4.2 The Working Group also considered this approach for the original proposal as a solution to the problem outlined above. However, some Working Group members believed that this would represent a cross-subsidy since Users in some zones would benefit from (potentially significant) over-recoveries in other zones despite the fact that they were essentially competing in separate auctions for separate zonal capacity. Despite the reservations of these Working Group members this approach is the favoured option of the Working Group as a whole.

3.9 Impact on the System Operator and Transmission Owners

3.9.1 The GBSO will receive all requests for local connections to the transmission system and will pass this information to the relevant TO.

3.9.2 The GBSO would administer the auction of wider entry access rights, including the publication of the required information after each round and monitoring allocation between rounds against the auction close-out criteria.

3.9.3 Following the auction, the GBSO will know the revenue to be recovered from generators based on the successful bids for long-term access rights in the auction. It is likely that there will be a difference between the total annual revenue recovered from the auction and the proportion of the maximum allowed revenue (27%) that is to be recovered from generation. This difference (surplus or deficit) will be passed back to all generation Users as part of the Residual element of the transmission use of system charge (“TNUoS”).

3.9.4 The TOs will know the transmission system reinforcements that are required and the associated timescales and will be required to complete them to time. In the event that such reinforcements are not completed to time, the GBSO would need to buy back that amount of capacity. Arrangements for the funding of such buy back payments will need to be agreed (outside of the CUSC, as is the case for other existing incentive schemes); for instance it may not be appropriate to expose the TO to any such costs that result solely from consenting delays.

4.0 SUMMARY OF WORKING GROUP DISCUSSIONS

During the Working Group meetings between April 2008 and December 2008 the Working Group mainly considered auction models where Users bid a price. When the first version of the Working Group report was submitted to the CUSC Panel the Working Group requested an extension to consider an auction model where Users bid capacity and duration. Section four is split into two sections: the first describes the discussions of the Working Group up to the first Working Group report and in the majority consider a price auction, the second describes the discussions of the Working Group during the eight week extension and consider a capacity and duration auction.

4.1 Price Auction

The following section summarises the discussions which took place in the Working Group during the initial period where the focus was on development of a price based auction.

The main feature of such an auction is that the System Operator publishes the availability of capacity in each year of the auction to the market and uses the prices submitted by Users to determine the allocation of rights.

4.1.1 Nature and Definition of Rights

4.1.1.1 The nature and definition of the long-term entry rights to be allocated through an auction process are proposed to remain the same as current rights apart from the following key differences: The rights will be allocated by auction and the rights will apply for a defined period (rather than allocated first-come-first-served and automatically renewed each year, as at present; the rights would be implemented zonally rather than nodally; the rights would be split into two components (local and wider); and final sums would be replaced by a generic commitment based on the accepted bid prices.

4.1.1.2 The majority of Working Group members believed that they currently had ‘evergreen’ transmission access rights (assuming they paid TNUoS) and it was not appropriate (or potentially legal) for these to be withdrawn through a CUSC amendment. The Authority representative stated their belief that rights under the CUSC were unclear, and that there are features of the existing rights which suggest they are not evergreen. National Grid noted that whilst the rights currently have evergreen characteristics, such features could be changed by making an amendment to the CUSC.

4.1.1.3 Some members of the Working Group suggested that if this were the case then rights to be allocated, via CAP166, could also, in the future, be removed (or fundamentally altered) via an amendment to the CUSC. The Authority representative stated that, in the case of future rights where parties have made a non-reversible financial commitment, this was unlikely to be appropriate. However, they did not believe that this was the case for existing rights.

4.1.1.4 Some members believed that if existing rights were evergreen, this would constitute a property right, and that such rights could not be changed solely by a CUSC amendment. However, the Working Group accepted the suggestion of the Chair that, without prejudice to those rights, in order to proceed with the work of developing and assessing CAP166 they had to set aside their views of existing transmission access rights.

4.1.1.5 Some members of the group considered that it may be hard for Users to know when their power station will close and therefore difficult for them to know for how long to bid for transmission access rights in the auction. Other members of the group considered that Users would be in better position to predict when their power station might close compared to transmission owners.

4.1.1.6 The amendment proposed allocating capacity in blocks of (whole) financial years of transmission access bookings. The group discussed whether shorter blocks should be offered, but agreed that this was addressed by CAP161.

4.1.1.7 The group discussed whether it was appropriate for the long term access rights to be zonal by definition, and whether zones would be stable enough for capacity to be allocated for 10 or 20 years (or indeed longer). The group considered that the auctioning of zonal rights would be complex to manage if the zones changed. Some of the Working Group were concerned that small portfolio or single station Users would be disadvantaged by zonal transmission access rights if they were implemented without other sharing arrangements (as proposed in CAP163). Zones were considered in greater detail by the (CUSC Transmission Access) Supporting Changes Working Group (known as "Working Group 3"), this discussion is summarised later in this report.

4.1.1.8 The Working Group discussions considered arrangements for wider access to the transmission network. Working Group 3 considered the appropriate arrangements for the local connection, and this is included in section 4.2. The interactions between the two products are however in section 4.3 below.

4.1.2 Generation Zoning and LCN Definitions – WG3 Discussions and Conclusions

Generation Zoning

4.1.2.1 National Grid recommended that in light of the proposed suite of CUSC Transmission Access Review Amendments (namely CAPs 161, 162, 163, 164, 165 and 166), it might be appropriate to move away from the existing TNUoS generation zones and develop a set of zones which better facilitate the release of transmission access via SO Short-term Entry Rights (CAP161), Entry Overrun (CAP162), Entry Capacity Sharing (CAP163), Long-term Finite Rights (CAP165) and Long-term Entry Capacity Auctions (CAP166). To help facilitate this work on zones the CUSC Amendment Panel established a separate group, known as Working Group 3, to assist Working Groups 1 and 2. Transmission Access Working Group 3 considered generation zoning in detail, a summary of their discussions is included in this section.

4.1.2.2 At the second meeting at Working Group 3 on 27th May 2008, National Grid introduced two separate generation zoning options in the form of: (i) a Scenario-based Zoning Methodology ("SZM"); and (ii) a Network-based Zoning Methodology ("NZM"). Both methodologies were proposed on the assumption that:

- local reinforcement works required to connect a generator to the MITS (and therefore make use of transmission capacity) are achievable;
- the resulting zones facilitated TEC exchanges within zones on a 1:1 basis; and
- limits (MW) at points of connection can be 'aggregated' in terms of their effects on wider transmission system constraints.

Scenario-based Zoning Methodology ("SZM")

4.1.2.3 The SZM considered the actual boundary constraints of the transmission system and followed the process of: (i) identifying candidate boundaries; (ii) identifying critical circuits for these boundaries based on the required transfer level specified within the GB SQSS; (iii) the calculation of sensitivity factors at all nodes with regard to critical circuits; and (iv) the grouping together of those nodes which have similar sensitivities.

4.1.2.4 In practice, candidate boundaries were identified manually based on the operational boundaries of the transmission network. The worst critical contingency and circuits were then identified against the indicative boundary. Sensitivity Factors were then calculated for each node by 'injecting' an additional 100MW of generation at each node within a zone and calculating the resultant flows on each of the relevant critical circuits under a contingency. Those nodes of Sensitivity Factors within a range of 20 percent were then grouped together.

4.1.2.5 The advantages of the SZM were observed as being that:

- maximum tradable transmission capacity within a zone could be derived from Sensitivity Factors for the winter peak scenario;
- the grouping of nodes of similar Sensitivity Factors into zones gives greater clarity and certainty to zonal transmission access; and
- additional constraint costs are minimised because actual transmission network constraints are honoured.

It was also noted that the publishing of nodal Sensitivity Factors leads to an indicative economic optimisation for TEC exchange.

4.1.2.6 The disadvantages of the SZM were noted to be that critical circuits tend to 'move' in meshed networks and that they are scenario and contingency dependent. Additionally, it was noted that zones developed under the SZM are unlikely to remain stable over a number of years due to changes to the transmission network and the demand and generation background.

Network-based Zoning Methodology ("NZM")

4.1.2.7 The NZM did not consider actual transmission boundary limitations, but worked on a 'hub and spoke' principle, considering the change in voltage angles resulting from the exchange of TEC at individual nodes as the parameter for determining relevant zones. It was identified that under the NZM, zones might be considered to be less likely to change so long as the network topology and impedance of the transmission network did not change significantly. And, where the SZM studied a few 'snapshots' of the transmission system, the NZM did not rely on a specific scenario being studied, hence providing more stability to the zones in the long-term.

4.1.2.8 Limitations of the NZM were identified to be that the choice of hub-node used to determine the zones was critical to the zonal definition and likely to have a significant impact on a generators ability to exchange transmission access rights. Additionally, it was noted that actual transmission system constraints might not be fully reflected.

Working Group 3 discussion

4.1.2.9 Working Group 3 noted that a significant amount of further information and analysis of both options was required, including the estimated total effect on transmission constraints, the stability of zones and the 'liquidity' of capacity exchange.

4.1.2.10 Working Group 3 questioned as to whether it would be possible to overlap zones in the NZM, or even have a unique zone for each node to maximise tradability. Concern was expressed however, regarding the impact of sequential trades from zone to zone and the potential impact of this on constraint costs.

4.1.2.11 In addition to the SZM and NZM, Working Group 3 questioned the possibility of the publication of node to node exchange rates in preference to zoning. The presentation slides regarding the SZM and NZM can be found on the National Grid Codes website.3

Indicative generation zones

4.1.2.12 At the fourth meeting of Working Group 3 on 16th June 2008, National Grid presented some indicative generation zones based on both the SZM and NZM. Zoning for regions that are radial in nature was relatively simple, the zoning process however, was much more difficult due to the presence of loop-flows.

4.1.2.13 It was noted that in the short to medium term (circa 2-3 years), National Grid (as the GBSO) can arrive at larger generation zones which may better facilitate the exchange of transmission access rights due to the greater certainties associated with background conditions and operational measures. In the longer-term however, it was considered that smaller generation zones would be required to cater for increased uncertainty.

4.1.2.14 In general, a number of key issues and findings were noted:

- Generation zones were generally different from the existing TNUoS generation charging zones.
- Short-term zones can be much bigger than the long-term zones, and they can change from time to time.
- In a meshed network, the effect of loop-flows may increase the percentage loadings on critical circuits and make it difficult to define zones.
- The definition of local works will affect zoning criteria.
- Being geographically proximate does not necessarily mean being electrically proximate, especially when substations are operated in a "split" configuration. In this instance, re-arranging of busbar sections or substation uprating may be required to facilitate TEC sharing.

Working Group 3 discussion

4.1.2.15 Working Group 3 noted the importance that any new zoning methodology should be suitable for all long and short-term transmission access products proposed under the suite of CAP161-166 amendments and gave consideration to the trade-off between the potential increased costs of operational constraints, the liquidity of absolute trades, and the number of nodes in each zone. It was considered that zones should be based on capability (e.g. local connection capacity) rather than obtained long-term transmission access rights (TEC or its equivalent).

Hybrid zoning methodology

[3] http://www.nationalgrid.com/NR/rdonlyres/9A797D89-2BC2-459C-A3C7-744F3212109F/25954/Meeting2Zoning.pdf

4.1.2.16 At the fifth meeting of Working Group 3 on 1st July 2008, National Grid presented some indicative generation zones based on a hybrid (of SZM and NZM) zoning methodology, in that a critical trip was applied (under n-d) with 100MW injected at each of the rim nodes and then extracted at the hub node. Following this, the loading of all lines under a combination of every rim-rim, rim-hub pair was analysed. If a loading increased by more than 20MW, this was then considered to be a 'sensitive' case. The exercise was repeated for a number of other critical trips with a sense check undertaken prior to determining the zones.

4.1.2.17 The methodology applied to determine a set of zones was as follows:

1. Set local works and size of zones (2 of the 3 variables – excluding constraints).
2. Identify active constraints based on existing knowledge of that selected zone.
3. Calculate the volume of additional constraints based on:
   - NZM sensitivities;
   - Load factors of buying and selling generators to calculate the volume of potential tradability.
   - Use realistic outage windows to estimate the number of hours of potential exposure to constraints.
4. Estimate the costs of constraining off and replacement energy.

Operational constraint costs

4.1.2.18 In addition to presenting some indicative generation zones and some of the issues surrounding the zoning process, consideration was given to the balance between facilitating transmission access tradability within zones and the consequences of constraint costs and stability.

4.1.2.19 Operational constraint cost is calculated based on the volume of active constraints (MWh), multiplied by the cost (£/MWh) of these constraints. It was noted that a small generation zone will lead to less trading options, though this might not necessarily be considered as a 'low' level trading. Working Group 3 members considered that a potential % cap of total zonal trades should ideally, be the same for all generation zones, although different zones may permit a far larger volume of transmission access trade for the same operational cost risk. It was considered that limits on trades would allow larger zones with more nodes, and that a limit could be set as a function of the load factor of generators, or proportions of the total transmission access capacity (MW) within a zone.

4.1.2.20 National Grid presented some high level analysis on the volume of additional constraints and the associated cost of this, based on a mid depth local works definition and the exchange of between 25-100% of TEC within a zone when compared to existing constraint costs of approximately £80m per annum.

Working Group 3 discussion

4.1.2.21 Working Group 3 noted that there is a trade-off between (i) nodal tradability, (ii) maximum zone size and (iii) how much local works must be completed prior to transmission access being allocated. For example, if a deep definition of 'local works' is applied then, as a consequence, zones are likely to be larger. It was reiterated that the existing assumption is that when transmission access is exchanged or shared, resulting in additional constraints, this additional cost will be socialised amongst all transmission system Users.

4.1.2.22 Working Group 3 noted that there are three different areas in the TAR proposals where local assets and works are defined: (i) within the CUSC; (ii) for local charging purposes; and (iii) within the zoning methodology. Working Group 3 considered that the disconnect between the actual local works that are required for a connection and the local charge which the User will pay may be necessary to:

- Avoid circumstances in which there would be a permanent output restriction on a generator being connected; and
- Protect the individual generator from the actions of others or the decisions of the Transmission Owner.

4.1.2.23 The Working Group noted that having separate definitions may be consistent with the way in which current Construction Agreements list the incremental works required to accommodate generators, with the generator paying the Long-Run Marginal Cost (LRMC) derived from the Investment Cost Related Pricing (ICRP) transport and tariff model. However, the Working Group subsequently agreed that different CUSC and charging definitions may lead to Users getting access rights without facing the associated cost reflective charge, as described in 4.1.3.11 below.

4.1.2.24 Working Group 3 considered that the stability of zones was very important and therefore new generation zones should not be developed in this process on the premise that zones are acceptable at present, but there may be issues to address in the future. The presentation slides relating to the hybrid zoning methodology can be found on the National Grid Codes website.[4]

4.1.2.25 At the sixth meeting of Working Group 3 on 16th July 2008, National Grid presented some indicative generation zones, using a 'mid depth' definition of local works and a lower Sensitivity Factor limit (20%). In order to avoid significant local works reinforcement conditions, very small zones were created which based on previous Working Group 3 discussions, were considered too small. However, it was noted that to fully appreciate the 'size' of zones, it is the number of trading parties and the amount of tradable transmission access capacity within a zone that should be considered more relevant than the geographic area.

4.1.2.26 In parallel, National Grid presented some further analysis on indicative generation zones based on a 'deeper' definition of local works, to assess how this may increase the tradability of transmission access. Several Indicative zones were created although it was noted that it was not possible to zone certain regions such as East Anglia on the basis of the deep definition, without invoking local works designs that were economically inefficient. In general, it was considered by the Working Group that moving to a deeper definition of local works did little to increase the size of zones and the potential liquidity of access sharing.

4.1.2.27 Working Group 3 noted that stability at nodes is important, but the possibility of considering (i) nodes with existing generation and (ii) nodes with signed applications (to connect to the transmission system at some date in the future) should be explored. This was not necessarily perceived to provide stability to zones beyond a 3 to 5 year period, but it was deemed workable if a fully automated and transparent model can be made publicly available to the industry.

[4] http://www.nationalgrid.com/NR/rdonlyres/1E709B88-B313-47B7-9835-2424C283798C/26845/GenerationZoning_final_meeting5.pdf

Generation zoning and nodal exchange rates

4.1.2.28 At the seventh meeting of Working Group 3 on 29th July 2008, National Grid recapped on the generation zones which had been presented to date, noting that these were based very much on existing generation centres, existing demand centres and radial spurs.

4.1.2.29 When identifying the generation zones, a number of factors had been raised as requiring consideration, particularly as to whether generation zones should be developed with a view to them being short-term or long-term, and whether they should be based on physical transmission system boundary limits or the additional constraint costs that these would be likely to produce. Given the complexity of zoning, attention of Working Group 3 turned to giving consideration of inter-zonal TEC exchange of transmission access and even the possibility of nodal TEC exchange of transmission access.

4.1.2.30 The options considered included the determination of a nodal 1:1 exchange rate based on the physical transmission network rather than generation background, which should therefore be temporally stable. This option would need to consider both long-term and short-term timescales, local charging definition and reflect network contingency analysis.

4.1.2.31 The second option was for a Locational Marginal Pricing (“LMP”) based approach for setting point-to-point rights. This bid-based approach can accommodate multiple constraints and payments would be made into a ‘pool’ based on the cost as compared to a hub point. Working Group 3 had concerns that the results would be volatile and that there would be less transparency behind the prices. In addition, the approach was felt to be complex.

4.1.2.32 Alternatively, a ‘flowgate’ approach was considered which would look at the physical capacity of constraining transmission circuits. This was felt to be a substantial change to existing transmission access rights, and with the example of around 1.5 billion nodal calculations per year required to update the Flowgate rights, Working Group 3 felt that this option was the most complex to implementation and was prone to volatility.

4.1.2.33 The last option considered was the use of a nodal exchange rate using a MWkm methodology. Consideration was given to using the Direct Current Load Flow (“DCLF”) transport model currently used to calculate TNUoS tariffs, to calculate nodal exchange rates for transmission access. This option involved taking into account various sets of contingencies, with the added advantage that some automation to identify all circuits was already available in the form of the Secured Load Flow model used to calculate to Global Locational Security Factor in TNUoS tariffs.

4.1.2.34 The weaknesses of this option were noted as being that the use of MWkm as a measure, does not equate to a critical circuit flow and as a result, overestimated transmission access exchange rates had already been identified at this early stage and would continue to be a significant risk. In addition, it was noted that there was no correlation to overloaded flow and the increase in GBSO costs that would be associated with this.

4.1.2.35 At the eighth meeting of Working Group 3 on 13th August 2008, as well as further developing the principle of a zonal methodology based on nodal exchange rates, National Grid introduced a zonal alternative and a nodal alternative.

4.1.2.36 **Nodal exchange rates:** A step by step methodology was discussed for establishing zones through grouping nodes between which the exchange rate fell within a certain range. Example exchange rates were shown for a particular approach based on specific assumptions. The approach was based upon worst-case contingencies in order to establish exchange rates, where the resultant zones would have minimal constraint costs arising from the exchanges. Transmission access exchange rates were shown for one set of possible assumptions. Working Group 3 was comfortable with the exchange rate discussed, which reflected the different impacts on a specific circuit from different nodes, but expressed concerns that under various critical trips the exchange rate may change significantly.

4.1.2.37 **Zonal alternative:** An alternative is to use zones that have already been defined (e.g. SYS, charging or candidate short/medium term generation zones), then the impact of such (i.e. increase in constraint costs) could be examined for an agreed suite of assumptions and scenarios. The Working Group agreed that careful assumption must be made around likely projects connecting and TEC sharing behaviour.

4.1.2.38 **Nodal alternative:** Working Group 3 considered an ex ante nodal exchange rate approach. The total impact on constraint costs is mitigated when Users who wish to share, notify the SO of the specific nodes between which the transmission access will be shared in addition to the maximum size of trade. This allows a more robust exchange rate to be established. Once granted sharing could occur over any timescale; without exposure to nodal overrun charges.

Sharing access rights between nodes

4.1.2.39 Given the issues identified with establishing zones in which sharing with a 1:1 exchange rate is allowed, at the ninth meeting of Working Group 3 on 22nd August 2008, the Working Group gave some further consideration to some potential options for sharing transmission access between nodes, without the requirement for generation zones. Three models were considered (the presentation is available on the National Grid Codes website):

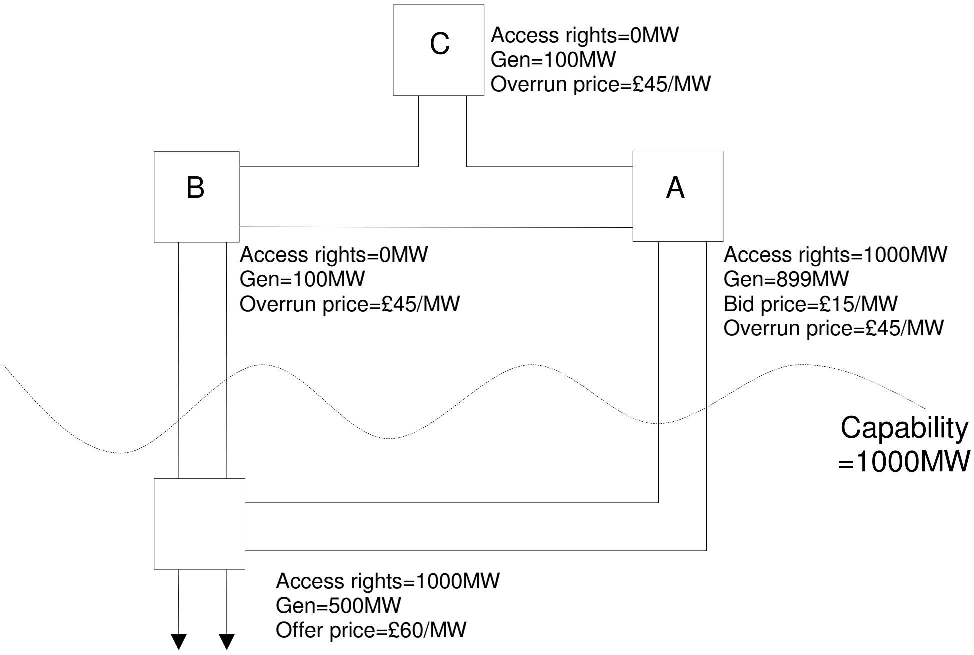
(a) Sharing with exchange rate determined by ratio of nodal (ex post) Overrun prices;
(b) Sharing with fixed point to point exchange rate calculated by National Grid based on known volume and duration; and
(c) Sharing facilitated by the release of point to point transmission access rights by National Grid in investment timescales.

Exchange rate determined by ratio of nodal Overrun prices

4.1.2.40 Under this option, the User would notify National Grid of a sharing arrangement agreed bilaterally between two parties. National Grid would then calculate exchange rates based on (ex post) overrun prices. The results from these calculations would then form the inputs into the calculation of overrun volume.

4.1.2.41 Whilst overrun prices allow Users to share transmission access rights to an extent, Working Group 3 considered that there was an issue with a bilateral exchange being affected by a third party generating, which would consequently affect the overrun prices and exchange rates

4.1.2.42 If we consider the simplified example (shown in the diagram below) of two generators behind a constraint, generator A has long-term transmission access rights and generator B does not. The overrun price increases above zero only if the aggregate output from both generators exceeds the long-term rights held by generator A. This means that provided generator A reduces output whenever generator B wants to generate, the overrun price faced by generator B will be zero.



4.1.2.43 This arrangement would break-down if there was a third generator, generator C, generating without transmission access rights behind the same constraint. The output from generator C could also cause the overrun price to increase above zero, undermining the effectiveness of the sharing arrangement between generator A and generator B.

4.1.2.44 In these circumstances, generator A is not able to extract the full value of their transmission access rights due to the actions of a third party. This would be solved if generator A and generator B were to enter a sharing arrangement with the associated transmission access exchange rate based on the ratio of the (ex post) nodal overrun prices. Now, if generator C decides to generate, this would push the overrun price at the generator A node and the generator B node such that the exchange rate remains constant.

4.1.2.45 In more complex examples, the actions of generator C may cause the exchange rate between generator A and generator B to diminish, as there would be a constraint between generator A and generator B, but the value of generator A's transmission access rights at generator B's node would always be accurately reflected.

4.1.2.46 Working Group 3 considered the following high-level process for exchange rates determined by the ratio of overrun prices, noting that this option for sharing transmission access rights was reliant on the approval of the CUSC amendment (CAP162) to introduce overrun prices calculated in a cost reflective manner. The Working Group subsequently agreed that this option was only applicable with overrun with a marginal price, as described in the Final Conclusions from Working Group 3 below.

(a) Users notify National Grid of sharing arrangement

i. It has been assumed that a joint request for a sharing arrangement would be made by a User with transmission access rights (seeking to donate) and a User without transmission access rights (seeking to receive).
ii. The request would state a 'go-live' date and 'end-date' for the arrangement, along with a maximum capacity in MW. The maximum capacity is included to allow a User to donate to a number of receiving Users.
iii. The request would need to be made [x] days ahead of time to allow for the necessary administrative process to be undertaken.
iv. The Sharing arrangement and associated 'go-live' date and 'end-date' would need to be recorded in a central register.

(b) National Grid calculates transmission access exchange rates based on ratio of (ex post) overrun prices

i. For a donation of transmission access rights from node A to node B, the exchange rate would be calculated as:

$$Exchange\ rate = \frac{Overrun\ price_{Node\ A}}{Overrun\ price_{Node\ B}}$$

Therefore, if the power station at node A reduces output to 100MW below its total transmission access rights holding, and the overrun prices are £45/MWh at node A and £50/MWh at node B, this would provide for the following at node B:

$$100MW \times \left[\frac{£45/MWh}{£50/MWh}\right] = 90MW$$

ii. This calculation would be performed for each half-hour for which the sharing arrangement is valid (i.e. between 'go-live' date and 'end date'.

(c) Results from calculations in (b) form inputs to calculation of overrun volume

i. It should be noted that this calculation is reliant upon overrun prices being calculated prior to the final volumes of overrun being known. (This cannot be done for the Cost Recovery methodology)
ii. The volumes of overrun at each node would need to be corrected for these exchange rates. If, in the example above, a generator at node B without access rights generated 100MW, this would initially be considered as 100MW of overrun, but the exchange rate would then be calculated which would essentially show a 100MW donation from node A providing 90MW of transmission access rights at node B and the overrun volume would be corrected from 100MW to (100MW-90MW=) 10MW.

Fixed point to point exchange rate calculated by National Grid

4.1.2.47 Whilst option 1 (exchange rate determined by ratio of nodal overrun prices) may be acceptable for Users that are reasonably (electrically) proximate, this is unlikely to be the case for generators that are further apart, due to the increased risk of a binding constraint that effects the receiving (but not the donating) generator. In order to facilitate sharing for these power stations, National Grid could calculate a fixed transmission access exchange rate that could be applied.

4.1.2.48 The work to investigate 1:1 sharing within pre-defined zones has identified significant risks due to actual node to node exchange rates being dependent upon:

(a) The volume of transmission access rights shared: A node to node exchange rate calculated based on a transfer of 1MW may be incorrect for a transfer of 10MW, 100MW or 1GW.
(b) Other transmission access right sharing: The exchange rate between nodes A and B may be incorrect if there is a transfer between nodes C and D.
(c) Other time dependent transmission system conditions: On the day transmission system conditions, such as demand and circuit outage conditions, also impact on node to node exchange rates.

4.1.2.49 In order to ensure that reasonable node to node exchange rates can be calculated, the User would need to minimise uncertainty by specifying the maximum volume of transmission access rights to be Shared and the timing and the duration of the sharing arrangement.

4.1.2.50 Working Group 3 considered the following high-level process for fixed point to point transmission access exchange rates calculated by National Grid.

(a) Users apply to National Grid for a fixed exchange rate
   i. It has been assumed that a joint request for a sharing arrangement would be made by a User with transmission access rights (seeking to donate) and a User without access rights (seeking to receive).
   ii. The Users would be liable to pay a fee to cover the cost of the analysis performed by National Grid.
   iii. The request would state a ‘go-live date’ and ‘end-date’ for the arrangement, along with a maximum capacity in MW. As described above, the fixed duration and maximum volume information is required to cap the risk associated with the sharing arrangement, allowing the SO to calculate a reasonable fixed exchange rate.
(b) National Grid calculates fixed point to point exchange rate
   i. The request would need to be made a number of weeks ahead of time to allow for an engineering assessment to be undertaken by National Grid (the number of weeks of analysis would depend on the duration of the exchange rate).
   ii. For applications for exchange rates within the current operational year, the assessment would be based on the current transmission system and would be performed against the requirements of the operational criteria contained in the SQSS. This assessment would reflect the information that is available in these timescales, including demand level and planned transmission system outages.
   iii. For applications for exchange rates that go beyond the current operational year, the assessment would be against the current and committed transmission system (including planned reinforcements) and would be performed against the requirements of the planning criteria contained in the SQSS.

iv. The Working Group subsequently considered that this assessment should not increase socialised constraint costs or sterilise boundary capability

(c) National Grid offers fixed exchange rate and User has 2 weeks to accept. If accepted, the Sharing arrangement and associated 'go-live date' and 'end-date' would need to be recorded in a central register and used in overrun volume calculations and future 'applications' for capacity/exchange rates. The appropriate charge for this was considered to be a cost-reflective fee based on the administration costs.

Point to point access rights released by National Grid

4.1.2.51 In the event that a fixed transmission access exchange rate provided by the aforementioned option above was considered to be unacceptably low, Users may want the Transmission Owners to invest in order to achieve a point-to-point capability. Such investment could be minor (and therefore relatively quick) when compared to the investment required to provide that same User with full entry rights.

4.1.2.52 In this option, a User would apply to National Grid for a transmission access right between [Node A] and [Node B] for a maximum of [x] MW and a duration of [Y] years. National Grid would then assess that application against the current planning baseline with an additional [X] MW of generation at Node A and an additional [X] MW of demand at Node B.

4.1.2.53 National Grid would then offer a point-to-point transmission access right to the User, with the offer including a list of reinforcement works triggered by that application. In the event that the User then accepts this offer, a point-to-point right is only available when reinforcements have been completed. The point-to-point right is recorded and used in overrun volume calculations and future 'applications' for capacity / exchange rates / point to point rights. It was considered appropriate that a User should pay the TNUoS differential between Node A and Node B for [Y] years.

Cost of Constraint Analysis on the Short/medium Generation Zones

4.1.2.54 The expected impact from implementation of the proposed short/medium term generation zones was presented during the tenth meeting of Working Group 3 on 12th September. An examination was made of the potential additional costs of constraints incurred as a result of transmission access sharing within zones. National Grid noted that where generators are permitted to connect to the transmission system without the requirement to undertake wider system reinforcement, this is likely to result in additional system boundary constraints and increase the constraint volumes on the existing constraint boundaries.

4.1.2.55 Working Group 3 considered that further thought regarding the range of assumptions was required in the pursuit of calculating the utilisation element of constraint cost. Problems with trying to make predictions about future constraint cost trends from using historic SO costs were identified. It was noted that in a zone which flips between importing and exporting, it is not appropriate to attribute a cost to the boundary constraint under a winter peak scenario as it might not always be obvious if costs are related to an export or an import. In these cases, the data used needs to be further analysed to properly attribute an export or import cost against the corresponding linear trending in export or import utilisation.

4.1.2.56 The locational element of constraint cost was also analysed. One to one trading was considered to be acceptable up to a point of 'headroom', beyond which a specific point to point arrangement would be required. It was noted that any trade undertaken will change the size and validity of the headroom. It was considered that this headroom figure could be fixed for a year, with some risk of an increase in constraints prior to re-calculation in the following year.

Initial Working Group 3 Conclusions

4.1.2.57 Prior to the eleventh meeting of Working Group 3 held on 24th September, National Grid circulated a report[5] that examined the potential additional costs of constraints that would be incurred by the sharing of transmission access within generation zones. The additional utilisation and location costs are calculated using a set of proposed generation zones. The calculations presented have considered factors including headroom, sensitivity factors and loading curves from the generators. The results indicated a total (utilisation + location elements) additional cost of constraints of about £37m per annum if trading up to the headroom level only is allowed. If trading beyond the headroom was undertaken up to 2 times the headroom, the cost of constraints could potentially rise to £1.1 billion per annum for the upper range and a potential saving of about £0.2 billion per annum for the lower range. The £0.2 billion saving is the total cost of constraint from the utilisation element plus the average historical cost of constraint that can be saved. The actual cost would vary depending on the system running arrangement, the characteristics of the generators and the duration of transmission access exchange.

[5] http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/workingstandinggroups/wg161-166/

4.1.2.58 During this eleventh meeting, a summary of the options considered was made. A zoning methodology that results in small zones, with a minimal increase in constraint costs, severely limits the liquidity of tradable capacity. The Working Group recognised that methodologies that form large trading zones provide greater tradability, although the increased operational constraint costs which could result from such zones was considered too great a risk. The remaining options are (i) Larger zones, with trading limited to headroom on a point to point and beyond basis, with an allocation process for headroom and subsequent re-allocation process following the completion of a trade, was considered as a viable option by the Working Group. The downside however, was identified as being the complexity of the arrangements which would be required, the potential for hoarding capacity and that trades would be limited to within-zone; or (ii) A nodal point to point option for the sharing of system access which the Working Group also concluded was a viable option.

Final Conclusions from Working Group 3

4.1.2.59 The final Working Group 3 meeting was held on the 10th November, during which the key issues and areas for further confirmation from the consultation phase were discussed. One Working Group Consultation response stated that zones will lead to increased shared constraint costs but conversely, an overly pessimistic methodology may lead to under utilisation of capacity sharing. The Working Group concurred that the analysis previously presented showed that a zonal methodology with large zones has a significant risk of increasing total socialised constraint costs. National Grid discussed how, when determining nodal exchange rates, all feasible worst case system operation scenarios must be considered, in order to meet the principle of maintaining cost levels.

4.1.2.60 A respondent stated that a node to node exchange rate that was significantly different from 1:1 would reduce the effectiveness of sharing. Working Group 3 concurred and reiterated that this is likely to lead to sharing to occur mainly between proximate generators and it was concluded that the exchange rate should be capped at a maximum of 1 to 1 in order to prevent the ability for a User with multiple generators to book capacity and share it in order to minimise transmission charges. A view was expressed in a consultation response that capacity entry sharing should be available in both long term and short term timescales to which the Working Group agreed, although it was recognised that exchange rates may differ between the two as certainty increases towards real time.

4.1.2.61 A respondent stated that a nodal exchange rate methodology must be robust and transparent, but it is felt that this may introduce unnecessary complexity and therefore cost. Whilst the Working Group agreed nodal point to point exchange rates requires a degree of complexity, ultimately it avoids the requirement to achieve a balance between limiting zonal tradability with an onerous headroom limit and introducing unacceptable risks through significant increases in socialised constraint costs. Working Group 3 therefore concluded that a node to node exchange rate methodology should be applied.

4.1.2.62 A respondent questioned how exchange rates based on zonal overrun prices would be calculated. The Working Group discussed the options for overrun pricing set-out in Charging Pre-consultation GB ECM-14 (Consequential impact of CUSC amendment proposals: CAP161, CAP162, CAP163 and CAP164). The options are:

(i) Simple Methodology;
(ii) Cost Recovery Methodology; and
(iii) Marginal Methodology.

4.1.2.63 The simple methodology is based on historic constraint data, which is mapped to 24 indicative constraint zones. This means that all the nodes in a particular zone would be subject to the same overrun price. The Working Group noted that implementing node to node exchange rates based on these overrun prices would essentially allow unfettered sharing with a 1:1 exchange rate within these zones.

4.1.2.64 The Working Group agreed that whilst these zones may give the appropriate level of accuracy for a simple pricing methodology (where the impact is limited by the Local Capacity Nomination), the analysis performed previously would suggest that allowing sharing on this basis would cause an unacceptable increase in socialised constraint costs. For this reason, the Working Group agreed that node to node sharing with exchange rates based on the ratio of ex post overrun prices should not be an option with the simple overrun pricing methodology.

4.1.2.65 Where the cost recovery methodology is based on a "degut" of the actual costs performed ex post by the System Operator, a methodology is used to attribute actual costs to the volume of overrun to calculate a £/MWh overrun price. Whilst, unlike the simple methodology, this cost allocation will be nodal, the Working Group agreed that this methodology would be inconsistent with node to node sharing based on the ratio of overrun prices. This conclusion is based on concerns about the interaction between the derivation of the price and volume of overrun (i.e. it would not be possible to calculate the overrun price until the overrun volume is known, and with sharing the volume is not known until the ratio of overrun prices is determined).

4.1.2.66 The marginal methodology is based on a model of the transmission system which is optimised to minimise system balancing costs. The optimisation generates nodal marginal overrun prices (shadow costs). The Working Group noted that this pricing option was at an early stage of development, but agreed that provided it was developed such that truly nodal (rather than boundary based) prices were produced, then it would be appropriate for use with node to node sharing with the exchange rate determined by the ratio of nodal overrun prices.

4.1.2.67 In summary, the Working Group agreed that node to node sharing with an exchange rate based on the (ex post) overrun prices should only be implemented if the marginal overrun pricing option is implemented.

4.1.2.68 One respondent specifically sought clarification for how codification could be implemented when three or more parties are involved in the transfer if the exchange rate is not 1:1. If different exchange rates are set for each exchange (there could potentially be 6 exchange rates for 3 parties) the codified approach would need to allocate TEC between parties such that monitoring can take place. The Working Group agreed that in cases where three or more parties are involved in the share, complex arrangements would be required to ensure an efficient outcome. Furthermore, the Working Group agreed that the number of parties involved in a share should be limited to two at this stage, but that this limitation should be reviewed when there is some experience of the sharing arrangements.

4.1.2.69 Several respondents to the Working Group Consultation requested clarification of how node to node access capacity exchange rates would be calculated. The Working Group agreed that further illustration would provide additional clarity.

4.1.2.70 The Working Group agreed that the basis of the exchange rate should be to "leave the system whole" such that any spare boundary capability is not used up and there are therefore no concerns about node to node sharing arrangements sterilising boundary capability.

Offshore generation

4.1.2.71 Working Group 3 gave consideration to offshore generation and how this would be incorporated into zones. It was noted that offshore generation is currently being modelled at the landing point, assuming a radial connection and Grid Code compliance at the point of connection.

Governance

4.1.2.72 Two approaches towards the governance of a new zoning methodology were considered by Working Group 3:

1. A new Licence Condition could be written into the Transmission Licence similar to that which exists for the Use of System Charging Methodology (Standard Licence Condition C5) and the Connection Charging Methodology (Standard Licence Condition C6).
2. The governance arrangements for the new methodology could sit in the CUSC.

4.1.2.73 The Working Group considered that the CUSC defines the transmission access product and since zoning is part of the definition of the product, then it would be appropriate to include this as an Annex to the CUSC. Whilst this was the preferred option, the option of a Licence Condition was not ruled out.

4.1.3 Arrangements for Local Connections – WG3 discussions and Conclusions

4.1.3.1 The arrangements for local connections were developed by Working Group 3, and the conclusions are described below.

Definition of Local Capacity Nomination

4.1.3.2 Working Group 3 proposed that for generators with local only connections, a local access product should be developed. This concept, the Local Capacity Nomination (LCN) would be the maximum capacity (in MW) to which a generator is entitled to obtain transmission access products (long-term and short-term access products and overrun) within a charging year. It was also identified that it must not exceed the Connection Entry Capacity (CEC) of that generator to avoid damage to local transmission assets.

Summary of the properties of Local Capacity Nomination

4.1.3.3 LCN was determined by Working Group 3 to have the following properties:

- LCN is the term used by a generator to notify National Grid of its desired maximum local capacity holding in a transmission charging year;

- LCN represents the physical (and contractual) cap on the total generators' transmission access (MW) derived from a combination of all long and short-term transmission access products, including overrun;
- LCN will not exceed a generator's CEC;
- LCN is defined on a Power Station basis (consistent with TEC);
- LCN will be allocated on a first-come-first-served basis;
- LCN will be the basis upon which a generators' local asset charge will be calculated and levied;
- LCN is shareable between generators, when multiple generators agree to share. Any sharing arrangement would be managed with a clause which, in the case of two generators sharing, would restrict one generator if the other generator is using the local connection capacity and vice versa. This approach is similar to that currently adopted to deal with design variation connections.

<u>Enduring arrangements for existing LCN holders</u>

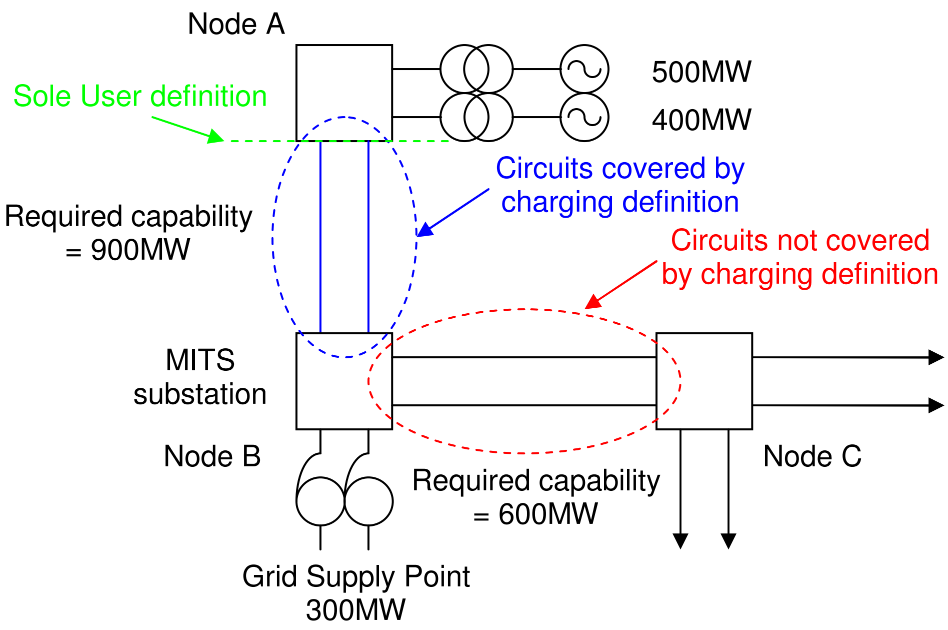
4.1.3.4 Working Group 3 debated as to whether LCN should be a finite right, linked (or not) to the period of firm transmission capacity obtained in an auction, or evergreen. Given that a generator may not wish to obtain long-term capacity through an auction process, it did not seem appropriate to link LCN to capacity obtained through the auction.

4.1.3.5 Working Group 3 considered that evergreen rights would be appropriate provided the definition of local assets is generally limited to "sole use" assets; i.e. local assets are not shareable. Where local assets (which are not shared) come to the end of their life, the TO could determine whether they should be replaced following bilateral discussions with the relevant generator. It was noted that the proposed charging definition of local works included shared use assets in some circumstances and some Working Group members believed that it might be appropriate to change the definition of local assets in these circumstances in order to ensure that they are not shared.

4.1.3.6 The problem with the "sole use" approach to local assets is that it may not in all circumstances be consistent with the principle of ensuring that Users which purchase short-term access products or share, make an appropriate contribution to the cost of the assets that are provided to facilitate their connection. If a "sole use" definition of local assets were to be adopted, then the cost of "spur" circuits to entry points with multiple generators will not be based on LCN (in MW). In the extreme circumstance of a generator choosing a "local only" connection at an entry point at which other generators are connected, that generator would not make any contribution to the cost of the transmission assets required to provide their connection.

4.1.3.7 This is shown in the below diagram. If a "sole User" definition were to be applied (this is represented by the dotted green line), neither generator would make any contribution to the cost of the spur (shown by the blue lines) required solely to provide their connection.

<u>Potential Definitions of Local Works</u>



4.1.3.8 The Working Group therefore concluded that local assets should not be limited to "sole use" assets. The Working Group considered that an alternative approach would be to use the definition from the "local generation charging" proposals contained in National Grid's GB ECM-11 Conclusions Report, which is that local circuits are those between an entry point and the next Main Interconnected Transmission System (MITS) substations, where a MITS substation is defined as a Grid Supply Point with more than one circuit connected or a substation with more than four transmission circuits connected. In the diagram above, these local circuits are highlighted in blue.

4.1.3.9 In this simplified example, the circuits between node A and the next MITS substation (node B) would be defined as "local" under the charging definition. This means that the generators at node A would get access once these circuits had been reinforced to provide a secure capability of 900MW. However, the circuits between node B and node C would not be covered by the charging definition of "local". This would lead to a permanent restriction to the output of the generators unless these circuits were reinforced to provide a secure capability of at least 600MW.

4.1.3.10 As described in 4.1.2.22 above, the Working Group originally considered that different charging and CUSC definitions of "local" works may be required to:

- Avoid circumstances in which there would be a permanent output restriction on generators being connected; and
- Protect individual generators from the actions of others or the decisions of the Transmission Owners.

4.1.3.11 On 10th November, Working Group 3 reviewed the consultation responses, allowing further discussion to be undertaken. The Working Group expressed concerns associated with different charging and CUSC definitions of "local" works. The Working Group noted that if the CUSC definition leads to reinforcement works that go beyond the next MITS substation in order to avoid permanent restrictions, then a User with LCN only will essentially be getting transmission access without paying the associated cost reflective charge.

4.1.3.12 Based on this concern, the Working Group agreed that the charging definition for local works should be consistent with the CUSC definition. The Working Group noted that there were scenarios where this definition could lead to a permanent output restriction being placed on a generator and that this would be reflected in bids for short-term access being turned down, restricted sharing exchange rates and high overrun prices. The Working Group also noted that the proposals for node-to-node sharing arrangements would allow generators in this position to apply for node-to-node access rights to facilitate sharing with other generators.

4.1.3.13 One Working Group Consultation respondent expressed concern that the initial view was to define LCN as a finite right, stating that generally local assets should not be shareable with other generators and that finite right arrangements are only required to redistribute assets that are no longer required by a User but can be used by other generators. During the final Working Group 3 meeting, the majority of Working Group 3 agreed that an enduring right approach was appropriate for sole User assets. National Grid completed some further analysis of the existing system and concluded that, given the relatively shallow nature of local works as defined, there were very few instances in which an enduring LCN right could risk causing inefficient investment of delays to the entry of new power stations.

4.1.3.14 It was acknowledged that since it is a feasible circumstance that multiple Users may wish to share LCN and the associated local assets, arrangements would be required to facilitate this. Working Group 3 agreed that this could be dealt with by including access restrictions in the generators connection agreement. This is similar to the treatment currently used to deal with connection design variations. The Transmission Owner would build sufficient local assets to cope with the shared holding of LCN only.

<u>Application processes</u>

4.1.3.15 New **connections:** Existing applications for new generation connections are progressed in line with Section 2.13 of the CUSC: *New Connection Sites, based on the desired CEC and TEC of the applicant.* Following any implementation of one or more of the suite of CUSC Transmission Access Review Amendments (CAPs 161-166), it is foreseeable that a generator may wish to obtain only short-term access products following connection. Given that a generator’s LCN will determine the level of obtainable short-term (and long-term) transmission access, and provide the basis upon which the TO decides on an economic level of transmission investment, the concept of LCN needs to be introduced into CUSC Exhibit B*: Connection Application*. A connection application will then be progressed under the same process as any other connection application.

4.1.3.16 Existing **connections wishing to increase LCN:** Section 6.30.2 of the CUSC: *Increase in Transmission Entry Capacity* defines the process by which generators can currently apply to increase their TEC. Any request from a User to increase its TEC for a connection site up to a maximum of its CEC is deemed to be a modification. This approach also appears appropriate for Users wishing to apply for an increase in LCN. In the event that multiple generators were sharing LCN, the application would have to be made on behalf of all of the generators involved.

4.1.3.17 Application **fees:** Given the proposed changes to the transmission access regime, it is considered appropriate that the current application fees included in the Statement of Use of System Charges, should be reviewed to differentiate between connection, local, and wider transmission system applications. Fixed and variable application fees will remain in operation. The Working Group noted in particular that generators wishing to increase LCN above their current TEC level during transition should not be exposed to the full Modification Application fee currently associated with changes in TEC.

4.1.3.18 **Pre-commissioning User commitment:** Working Group 3 identified that there are a number of potential options for arrangements to provide pre-commissioning User commitment:

- Cost-reflective final sums liabilities (possibly capped at the original offer);
- A liability based on the relevant Unit Cost Allowance (UCA); or
- A liability based on a multiple of the local generation TNUoS tariff.

4.1.3.19 Working Group 3 concluded that the requirement for pre-commissioning security associated with increases in LCN should be consistent with the arrangements proposed for wider long-term transmission access under CAP166.

4.1.3.20 The CAP166 original proposal for wider rights is a liability that ramps up over the 4 years prior to completion, to a total of 8 times the local generation TNUoS tariff. The 8 years is derived from analysis of TNUoS tariffs against wider UCAs, which shows that, on average, the UCAs are 15 times the TNUoS tariffs. The 15 is halved to reflect a 50/50 risk sharing between generators and consumers. Consistency would imply that the same multiplier could also be used for local connections.

4.1.3.21 However, there is an additional rationale for 8 years being an appropriate multiplier: If local TNUoS was exactly reflective of capital costs, then a capital payment of 8 x annuitised TNUoS would cover 50% of the capital costs. This is because the TNUoS methodology converts capital sums by assuming a 50 year asset life and a 6.25% rate of return. Annual sums can be converted into a capital sum by multiplying by:

$$(1-(1+0.0625)^{-50})/0.0625 = 15.22$$

4.1.3.22 If the 50% risk sharing, consistent with the CAP166 treatment for wider access is applied, the result is a multiplier of 8.

4.1.3.23 Local TNUoS would not recover all costs, due to Users paying for what they are using rather than what is installed. It therefore would seem appropriate that security is also provided on this basis, and that security should not be provided for TO investments made for wider system reasons.

4.1.3.24 The Working Group therefore concluded that pre-commissioning User commitment for local commitment should be based on a multiple of 8 years of local generation of TNUoS, profiled 25%/50%/75%/100% over the 4 years prior to completion.

4.1.3.25 Termination or reduction of the requested LCN would therefore result in the levying of a Local Capacity Reduction Charge, based on Local Cancellation Amounts. The Local Capacity Reduction Charge would be non-refundable.

4.1.3.26 The Local Cancellation Amount in each year would be a percentage of the Local Termination Amount, which is the higher of zero and eight times the relevant local generation TNUoS charge. The Local Capacity Reduction Charge would therefore be calculated as:

Local Capacity Reduction Charge = LCN_r *x* $LCAM_t$

Where:

- LCN_r is the reduction in Local Capacity Nomination in kW.
- $LCAM_t$ is the relevant Local Cancellation Amount which varies according to the number of full years from the Completion Date:
  - o In the year prior to the Completion Date (i.e. t) *LCAM = LTA x 100%)*, where LTA is the Local Termination Amount;
  - o Where t=-1, *LCAM = LTA x 75%*;
  - o Where t=-2, *LCAM = LTA x 50%*; and
  - o Where t=-3, *LCAM = LTA x 25%*.

Local Termination Amount = Max (0, ($LocGenTNUoS_n$ *x X))*

Where:

- $LocGenTNUoS_n$ is the relevant nodal Local Generation TNUoS tariff applicable to the generation project and published in the Statement of use of System Charges. If such a nodal tariff is not currently published, then the appropriate tariff will be calculated by National Grid as part of the application process, in accordance with the Charging Methodology.
- *X* is a multiplier, initially taking the value 8, although it may be appropriate that this be amended in subsequent price control periods.

4.1.3.27 Local Cancellation Amounts will be calculated using the prevailing local Generation TNUoS tariff at the time of Capacity Reduction. Capacity Reduction Charges would not apply to projects where there are no transmission asset works.

4.1.3.28 **Pre-commissioning security:** The introduction of generic Local Capacity Reduction Charges, defined in the CUSC to replace the existing final sums regime, defined in the bilateral Construction Agreements, will also require the introduction of provisions to define the level of financial security that should be held in relation to these potential liabilities.

4.1.3.29 It is therefore to add the applicable Local Cancellation Amount to each User's Security Requirement, as defined in paragraph 3.22 of the CUSC. To the extent that these amounts exceed the Allowed Credit extended to each User, Security Cover will need to be provided to National Grid, in any of the forms prescribed in the CUSC.

4.1.3.30 Working Group 3 noted that alternatives to the CAP165 original amendment proposal had also been developed by Working Group 2, including cost reflective final sums liabilities. The Working Group noted that should these CAP165 alternative amendments be approved, then they would also amend the pre-commissioning liabilities and security associated with LCN to be cost reflective final sums liabilities, 4.1.3.31 Existing **connections wishing to decrease LCN:** Section 6.30.1 of the CUSC: *Decrease in Transmission Entry Capacity* defines the process by which generators can currently reduce their TEC. Essentially, a User is entitled to decrease its TEC giving five business days notice in writing, prior to the 30 March in a financial year, with that notified decrease in TEC taking effect on 1 April of that same year. When discussing the possibility that LCN could be evergreen, the Working Group considered that this process could be applied to LCN. (The Working Group also noted the discrepancy between the late March deadline and National Grid's requirement for charge setting data to be provided no later than 23rd December in the previous (charging) year. The Working Group recommended an alignment of the notification timescales associated with TEC / LCN reduction with the TNUoS charge-setting process.

Transitional arrangements to LCN

4.1.3.32 Working Group 3 considered three options for transition from the current arrangements to those which require a Local Capacity Nomination.

- LCN based on a generator's CEC
  Given that CEC is not currently linked to transmission access allocation, this option seems the least appropriate.
- LCN based on a generator's TEC
  Given that the suite of CUSC Transmission Access Review Amendments (namely CAPs 161, 162, 163, 164, 165 and 166) are potentially introducing some fundamental changes to the way in which transmission access is allocated, existing TEC may not be considered appropriate for some generators.
- Generators would request its desired LCN in advance of a pre-defined date
  Working Group 3 concluded that this option appeared to be the most practical solution, although it was noted that the value notified will be limited to a generators CEC. In the event that a generator did not notify National Grid of its desired LCN, the use of TEC as a default value seemed appropriate. In the instance that multiple generators wish to share an LCN, a process for notification will be required. Timescales for a generator to notify National Grid of its desired LCN value will be very much dependent on the transmission access products implemented.

4.1.4 Local Works and their interaction with Wider Access Auctions

4.1.4.1 The Working Group discussed at length the issues surrounding the definitions of Local Capacity Nominations and their impact on the Auction process. Note that the Working Group did not discuss in depth the definition of LCN, or the assets that make up the LCN. The assumption was made that the LCN fundamentals developed by Working Group 3 would form the starting point for Working Group 2's discussions, albeit Working Group 3's conclusions were adapted to suit the auctions process. More complete details on the LCN definition and the changes made can be found in section 4.3 above.

4.1.4.2 The primary concern of the Working Group was that the proposed split of transmission assets to "local" and "wider" should be that the existing "queue" of Users awaiting wider transmission access rights should not be substituted by one of Users awaiting their local works to deliver an LCN value.

4.1.4.3 Though the two processes of allocation and indeed charging for the two categories of access rights are distinct there is a clear interaction between the two, especially given a key condition of the enduring auction regime is that a User may only bid in an auction for wider access rights providing it has an effective LCN for the period it is bidding for. The key question is whether to let the LCN allocation drive the wider auction result, or vice versa. Both approaches were discussed in both a transitional context and an enduring context.

Approach 1: Auction Result drives LCN Allocation - Transitional Context

4.1.4.4 The initial stage of the process is to withdraw all existing local and wider access rights from Users. Those withdrawn local rights are then substituted for a local right to procure wider access to a level up to their LCN. Each User's LCN MW level and effective date initially defaults to its pre-existing TEC MW level and TEC effective date[6]. Should the User be satisfied with this default allocation, it need do nothing and it will retain this default position as its firm LCN MW level and effective date.

4.1.4.5 Should a User wish to vary an aspect of this "default" LCN (either the MW level and/or the effective date) it will then need to notify National Grid of this intention – either through a Modification Application or through an as yet to be defined transitional process.

4.1.4.6 Once notified of the User's aspirations to vary its LCN from the default position, National Grid will determine any works required to accommodate these, and in doing so calculate two possible dates by which these works can be completed. The first such date is the "earliest LCN date" – this is the soonest date by which the works can be completed assuming that this project's works are considered in isolation to any other works – i.e. there is no constraint on construction resource.

4.1.4.7 The second date calculated is the "back-stop LCN date". This date is the soonest date by which the works can be completed, but in this case that this project's works are considered alongside any other works to deliver other projects earlier LCNs (these other projects may be grouped on a national basis or perhaps on a narrower regional basis). The back-stop LCN date is then selected as the soonest that the entire group of project's works to deliver LCN can be completed. It will be identical for all projects in the group.

4.1.4.8 Both the "earliest LCN date" and the "backstop LCN date" are conditional dates based upon the results of the next auction for wider access rights.

4.1.4.9 Each User will then be permitted to bid in the wider access auction for any years that it chooses to, provided that the years it is bidding for are not sooner than its "earliest LCN date". It is then assumed that those projects may procure wider access over varying timescales, some being successful in advance of their "back-stop LCN date", some perhaps as early as their "earliest LCN date", some may be unsuccessful or may choose not to participate and rely on short-term products (including over-run) to secure wider access.

[6] For existing generators the "pre-existing TEC effective date" will be the "Go-Live date" for any auctions process, for pre-commissioning generators this will be the Completion Date in its Construction Agreement

4.1.4.10 Those Users that are successful in the wider access auction will then have their LCN effective date advanced within their Bilateral Agreement to align with the first year in which that User has secured a non-zero volume of wider access capacity. The Working Group noted the concern that Users may bid for very small capacities for a single year in order to obtain an advancement in their LCN date. The LCN date will also at this stage become firm. Those that are not successful / do not participate in the wider auction will retain their back-stop LCN date as their firm LCN date.

4.1.4.11 Some Working Group members suggested a potential enhancement to Approach 1 the aim of which would be to further optimise User's LCN effective dates. The scenario was discussed where the above process described in paragraphs 4.4.4 – 4.4.10 had been completed but that there still scope to further optimise the LCN effective dates of Users who had been allocated their "back-stop LCN date". This some Working Group members felt may be possible if sufficiently few parties behind a local works resourcing constraint had been successful / taken part in the auction for wider transmission access. Thus there was still the capability to bring forward some of these User's works to facilitate an earlier LCN effective date.

4.1.4.12 The Working Group discussed the means by which such a further level of LCN optimisation might occur and two approaches were put forward:

- The first is to use the final results of the auction model and from it interpret which of the unsuccessful bidders would have been next in line to be allocated wider transmission access. Once these Bidders had been identified they could have their LCN works brought forward in their auction ranking order until such time as any remaining local resource allocation was exhausted. However some members of the Working Group felt that using the auction model in this way was not suitable given that it is set up purely to allocate wider transmission access.

- An alternative method also discussed by the Working Group was to further bring forward LCN effective dates on a first-come first served basis (based on Application Date).

Approach 1: Auction Result drives LCN Allocation - Enduring Context

4.1.4.13 In the enduring context it might be anticipated that the volume of new projects applying for connection in a given year would not lead to their being a "queue" for local access. In such cases it is more likely that the "earliest LCN date" equals the "back-stop LCN date" and is in line with the applicant's anticipated project timescales. This would then mean that the requirement to reallocate LCN dates following the wider access auction would not arise.

4.1.4.14 However should there be the resource constraint for works to permit the earliest allocation of LCN due to a number of projects applying to connect in the same year then a similar process to that for the transitional period as described above could be extended to the enduring regime.

Approach 2 – LCN Allocation drives Auction Result – Transitional & Enduring Context

4.1.4.15 Again in this approach all Users have their existing local and wider access rights withdrawn and the local rights are reallocated through their LCN. The LCN is again defaulted to the User's pre-existing TEC MW level and its TEC effective date.

4.1.4.16 Again should Users wish to amend this LCN beyond the default level (either in terms of its MW level or its commencement date) and this requires works to be carried out, once National Grid has assessed the magnitude of these works it will offer a User a "LCN commencement date".

4.1.4.17 The "LCN commencement date" will be calculated such that each project requesting an acceleration of its LCN date will be brought forward as far as construction resources will allow. In the event that two or more projects are subject to a resourcing constraint for their LCN works such that one or more, but not all of the projects could have their works completed by a certain date but the remaining projects would follow at a later date, then all of the projects would be given the same, **later** date as their LCN commencement date". These LCNs would at this stage become firm.

4.1.4.18 The auction is then run to permit those Users to procure wider access with the proviso that Users are only able to bid for wider access rights from their "LCN commencement date". For the avoidance of doubt, no further optimisation of the LCN commencement date is performed following the results of the wider auction.

4.1.4.19 Note that this model would work unchanged for either the transitional case or the enduring process.

<u>*LCN Allocation - Conclusions*</u>

4.1.4.20 The Working Group's believed the two approaches outlined above had the following advantages and disadvantages of the two approaches.

<u>*Approach 1 – Advantages /Disadvantages*</u>

4.1.4.21 ADVANTAGE – WIDER AUCTION NOT INFLUENCED BY LOCAL QUEUE: As noted above a key objective was that a wider access queue is not replaced by a local access queue. Given the feedback loop between wider and local access rights enshrined within Approach 1 there are fewer constraints resulting from local access issues feeding into the wider access regime.

4.1.4.22 ADVANTAGE – EFFICIENT ALLOCATION OF LOCAL RIGHTS: The feedback loop between the wider access auction and the allocation of local rights does mean that if a project is able to progress it own construction works more quickly than another project and is able to procure wider access to reflect this, then it will not be frustrated by having to wait for local access.

4.1.4.23 DISADVANTAGE – COMPLEXITY: Another consideration to be made with approach 1 is that if wider access is not constrained but local access is then there might be the scenario where all of the projects with clustered future LCN might be successful at procuring wider access at their "earliest LCN Date". However the LCN works to deliver this level of wider access are not physically deliverable. It would be anticipated that in these cases the auction model would be developed such that it accounted for LCN constraints as part of its allocation of wider access. For instance not allowing more than a pre-defined MW volume or number of new connections to be accepted in any one period. This would however add further complexity to the auction model.

4.1.4.24 DISADVANTAGE: IMPACT UPON SHORT TERM TRADED OR SHARED PRODUCTS: The key defect of the above approaches is that they disadvantage categories of User whose access procurement strategy is predominantly in the shorter term traded or shared access products. This is an inevitable consequence of the requirement to prioritise resources to deliver local connections. It is clear that an unambiguous signal is needed to allow National Grid to determine which projects should be progressed in preference to others. The only signal available is that which emerges from the wider access auctions and so those that choose not to actively participate in these auctions will have less priority under this model than those that do participate in the wider access auctions.

Approach 2 – Advantages /Disadvantages

4.1.4.25 ADVANTAGE – LESS COMPLEX: As approach 2 already resolves local access issues prior to the auction then there is no need to resolve these as part of the auction model.

4.1.4.26 ADVANTAGE – IMPACT UPON SHORT TERM TRADED ACCESS PRODUCTS: Approach 2 by allocating local access without accounting for a signal from the wider access auctions does not differentiate between those projects that are seeking wider access in the long-term or the short-term markets.

4.1.4.27 DISADVANTAGE – LOCAL QUEUE FORMED: Approach 2 would mean that the existing wider access queue would be replaced with an albeit smaller, but still significant local queue.

4.1.4.28 DISADVANTAGE – SUB-OPTIMAL ALLOCATION OF LOCAL ACCESS: Given the significant numbers of projects currently in the access queue who it would appear would wish to accelerate their local connection dates in any new regime that allowed them to the allocation of these rights in an optimal manner is crucial. Given the large numbers of post-2016 offers that exist it may be difficult to allocate each of these with a “LCN commencement date” that isn’t interactive with other projects. As this “LCN commencement date” is by definition the latest that all grouped projects can be accommodated, it is somewhat inevitable that some projects that could have been locally connected earlier (if approach 1 were adopted) in fact are connected much later under approach 2.

LCN Allocation Method - Conclusions

4.1.4.29 The Working Group undertook further discussions following the close of the Working Group Consultation and concluded that an approach based upon Approach 1 would be appropriate to take forward subject to the following enhancements.

4.1.4.30 The high level process would commence with an allocation of local access rights to existing Users[7]. The level of local access rights granted to a User would be denoted by its Local Capacity Nomination (LCN); the LCN would form the upper limit on the combined wider capacity a User may procure through any auction or short-term access products (including overrun). An LCN would consist of a MW level and a date from which that MW level is applicable. Staged projects might see a ramp up of LCN as the project is progressively completed.

4.1.4.31 The default LCN value granted to an existing User would be the TEC level granted in its Bilateral Agreement. For those projects yet to commission / energise the effective date will by default commence at the same time the TEC value was due to come into effect (as specified in the BCA) and will carry the same MW level as the existing TEC value.

4.1.4.32 Once the stages above have been completed for existing Users then so the enduring process will come into effect for any existing Users that wish to explore a change in their local access rights. Each User that wishes to change the timing or level (MW) of their LCN from its default TEC value will signal this intent to National Grid (this may be through a Modification Application or some other transitional process to be defined). Similarly the following process will be followed by any new Users applying to connect a Power Station to the GB Transmission System.

4.1.4.33 National Grid will for each connection application (or transitional) request calculate two dates the “earliest LCN date” and the “backstop LCN date”. The “earliest LCN date” is the earliest date by which works to deliver the desired LCN capacity could be completed (assuming they were commenced from the beginning of the next financial year and if that project was considered in isolation). The “back-stop LCN date” is calculated using a similar process but considers the earliest date by which all projects that wish to advance their LCN can have the works delivered to do so. It is clear that in all cases the “earliest LCN date” <= “back-stop LCN date”.

4.1.4.34 Any projects that wish to increase their LCN MW level will also have an assessment of whether there are any additional local works necessary to accommodate this and if so this may impact upon one or both of the offered “earliest LCN date” and “back-stop LCN date”. Both the notified (offered) “earliest LCN date” and “back-stop LCN date” will be conditional in two areas:

- The results of the next wider access auction; and,
- Applications from other Users (“subsequent User(s)”) to connect in the same locality as the “first User” which are received after the “first User” has received its offer and which are signed by the “subsequent User(s)” before the cut-off date for the next wider access auction.

4.1.4.35 Regarding the conditionality with the results of the wider access auction, a User will only have its final LCN Effective Date firmed up once it is known whether it has secured wider access in that auction. Those Users that are successful in the wider access auction will then receive a firm LCN effective date that aligns with their booked wider access rights. Those parties that fail to secure wider access rights in the auction will then be offered their “back-stop LCN date” as their firm LCN Effective date.

[7] The Term “existing Users” denotes any User that has a signed Bilateral Connection Agreement or Bilateral Embedded Generation Agreement by a certain “transition date”

4.1.4.36 The conditionality in advance of the auction would work along the following lines. The first User to apply to connect in a locality may receive an "Earliest LCN Date" and a "Back-Stop LCN Date" that are the same and equal to the date to facilitate only that User's Power Station. Then a second User applies to connect in the same locality. The second set of local works to facilitate the LCN is more complex than the first Users so the second User is offered an "Earliest LCN Date" equivalent to that offered to the first User, but its Back-Stop LCN Date is further into the future reflecting the more complex works to connect two Power Stations in the same locality. The first User must then also have its Back-Stop LCN date amended to be consistent with the first User.

4.1.4.37 In the above example the capacity constraints to deliver the local works for the two Power Stations will be reflected in the incremental capacity supply curves that feed into the auction process. This will ensure that only one of the two generators in the locality (in the above example) will be able to procure wider auction access in timescales consistent with their Earliest LCN Date. The other will then only be able to procure access consistently with the Back-Stop LCN Date.

4.1.4.38 It should be noted that in situations in which the provision of local capacity is constrained, these arrangements prioritise the provision of local capacity based on the outcome of the auction for wider long-term transmission access rights. By the end of the above process the "queue" for local works would have effectively been optimised based upon the desire of the User to commit to wider long-term transmission access.

4.1.4.39 In circumstances in which local capacity is constrained and priority is given to those Users that are successful in the auction, but some local capacity remains available, this would be allocated on a first-come-first-served approach (similar to that currently adopted for interactive offers).

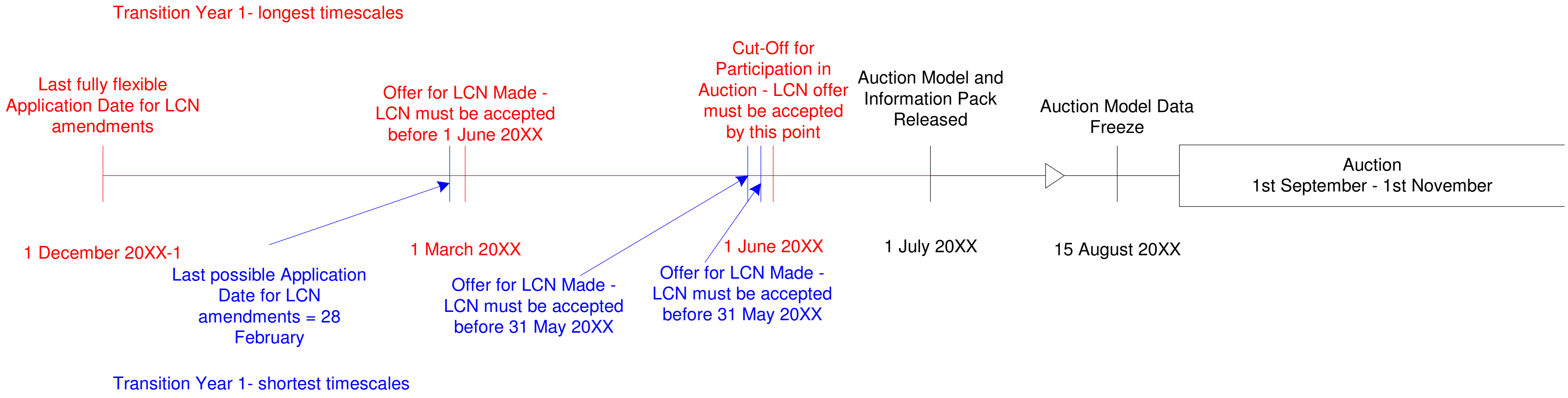
Mechanism to trigger LCN re-allocation

4.1.4.40 Another area of discussion undertaken by the Working Group was the mechanism by which this reallocation process could be instigated. Some members of the Working Group suggested that a Modification Application could be used as for an advancement of or increase in the value of LCN would require National Grid to undertake system studies before making an offer to the User in a similar manner to that undertaken when considering a Mod App. Other members of the Working Group were concerned that a formal Mod App may result in the eventual LCN offer being conditional on other issues that have a scope much wider than a strict local assessment of LCN, and thus a Mod App was not necessarily the most appropriate way forward. As such a separate transitional process more narrowly defined than a Mod App should be developed as part of these proposals.

Timescales for the Application of LCN

4.1.4.41 The Working Group also considered the timescales around which Users would need to apply for a new connection or notify National Grid of their wish to amend their LCN such that they would be in a position to accept an offer with the appropriate LCN in it in time to participate in the next annual auction for wider access. These timescales are shown in the diagram below:

Timeline showing local connection offer and wider auction processes



4.1.5 Auction Objectives

4.1.5.1 National Grid proposed a number of high-level objectives of an auction for long-term transmission access, which included:

- Implementation of a mechanism to allow parties to signal both the volume of access rights they require and the price they are prepared to pay;
  This means that existing (baseline) capacity can be allocated to those parties that value it most, and that greater flexibility can be given in the provision of an economic justification for the release of new (incremental) capacity.
- Implementation of a process that allows baseline and incremental capacity to be allocated in a consistent way;
- A requirement for parties booking long-term transmission access rights to pay at least the associated cost-reflective charge (i.e. there should be a reserve price). If parties are not willing to pay such a charge, transmission access rights should be held back and released in the short-term.

4.1.5.2 The Working Group discussed these objectives and how they could be achieved. Given the importance of the allocation of baseline transmission access (MW) capacity, particularly given its current scarcity in many areas of the transmission network, the Working Group discussed how baseline and incremental capacity would be defined. This definition would need to take account of the current capability of the transmission system which is quantified by performing network analysis against the requirements of the Security and Quality of Supply Standard. The Working Group agreed that the means by which this network analysis is incorporated into the auction design would be critical.

4.1.5.3 The Working Group also discussed the importance of the economic justification for the release of incremental capacity and a consistent treatment between baseline and incremental capacity. The Working Group noted that an economic justification for transmission assets is achieved by looking across multiple years and agreed that the ability to do this would also be critical to the auction design.

4.1.6 Auction Design

4.1.6.1 The following section summarises the Working Group discussions on value-based long-term transmission entry capacity auction design.

<u>Design considerations</u>

4.1.6.2 In developing an auction design for long-term entry capacity, the Working Group discussed the treatment of the following key issues:

(d) Network analysis
  - Zonal model;
  - Nodal load flow model;
  - Boundary constraint model.

(e) Baseline and incremental capacity
(f) Definition of baseline capacity
(g) Incremental capacity
(h) Pricing
(i) Reserve price
(j) Static/dynamic

<u>Network analysis</u>

4.1.6.3 One of the features of transmission networks is the interaction between connected Users. In the case of the interaction between different generators in the long-term, this is currently handled with ex ante network analysis against the requirements of the (GB) Security and Quality of Supply Standard (SQSS). This analysis is primarily based on avoiding unacceptable conditions during any two concurrent transmission circuit outages at peak winter (average cold spell) demand.

4.1.6.4 In the case of a generator applying for a new connection, this analysis is performed in order to determine whether reinforcements to the transmission system are required to accommodate the new generator in addition to existing contracted generation. It is worth noting that the existing contracted generation in this context is assumed to be relatively static. Where a requirement for transmission reinforcements is identified, these reinforcements are listed in a Construction Agreement and the new generator has to wait until these reinforcements are complete prior to connection.

4.1.6.5 For an auction solution, the existing contracted generation cannot be assumed to be static because all pre and post commissioning generation is competing for scarce access rights. .

Potential network analysis approaches for the auction

4.1.6.6 An auction design must include some form of network model to ensure that any rights allocated can be delivered by the network. Three network models have been considered by the group. These are

- Zonal model
- Nodal load flow model
- Boundary constraint model

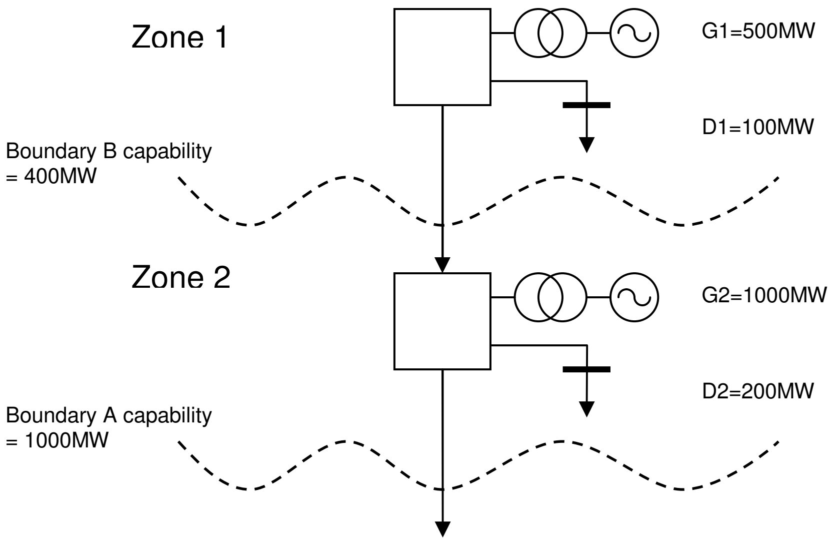
4.1.6.7 These models differ from each other in their balance between the accuracy with which the system is modelled and the transparency of the results to the auction participants. Each of these models will be discussed in turn

Zonal Modal

4.1.6.8 The original modification proposes a zonal auction. Under this approach, National Grid (as GBSO) performs network analysis ex ante to establish baseline capacities that are available in each zone. Transmission access rights are then allocated in a set of separate capacity auctions for each zone. This approach has the benefit that it is relatively straightforward for participants to understand due to the fact that the auction in each zone is independent from other zones. However, it may not result in an optimal allocation of capacity between zones.

4.1.6.9 For example in Figure 1, there are two transmission boundary constraints, A and B. If we consider boundary A, the total generation bidding for access behind this boundary (G1+G2) is 1500MW. If we subtract the total demand behind this boundary (D1+D2) of 300MW, this leaves a total export requirement of 1200MW to accommodate all generation (G1+G2) against a boundary capability limit (at boundary A) of only 1000MW. The issue is how this 1000MW of boundary capability should be allocated between zones 1 and 2.

Figure 1: Interactive zones example



4.1.6.10 If, for example, 400MW is allocated to zone 1, since this is what can be accommodated across boundary B, and the balance of 600MW to zone 2, this would only give an efficient outcome if the generation in zone 1 is willing to bid at least as much as the generation in zone 2. If the generation in zone 2 is actually prepared to bid higher than the generation in zone 1 then the more efficient answer is to allocate a greater share of the boundary A capacity in zone 2. The issue with this approach is that the GBSO would need to make assumptions about the capacity available in each zone, and these assumptions would determine the overall efficiency of the auction. Arguably, the most appropriate starting point is to allocate transmission capacity to zones in accordance with the transmission access rights that are allocated today.

4.1.6.11 The zonal approach is weighted towards transparency for the User at the expense of accuracy of modelling the system. However, if the expectation is that the auction will not lead to significant changes to the transmission access right holders, then the inaccuracies associated with this approach may be deemed to be acceptable. The majority of the Working Group felt that the outcome of the auction result would be driven as much by the allocation of capacity between zones prior to the auction as by the bids of participants. It was therefore felt that a more sophisticated network model was required.

Nodal load flow model

4.1.6.12 An alternative to the zonal model approach is to have a nodal load flow model underpinning the auction. A transmission network model is established which contains peak demand, circuit capabilities and all credible contingencies which are modelled in sufficient detail to cover interactions between the maximum circuit flows and generation connections. Users can bid for capacity, with an optimisation being performed to maximise bid revenue whilst honouring the system constraints from the network model. The entry capacity will be allocated to the highest bidders up to the transmission circuit capabilities.

4.1.6.13 The advantage of this option over the alternatives is the increased accuracy due to the presence of a nodal load flow model which is run during the allocation process as Users at different locations signal their requirements and the associated value they place on them. However, a full load flow solution is complex and therefore would be expensive and involve a significant lead time.

4.1.6.14 It should be noted that the nodal load flow model would only accurately model thermal capability restrictions, and not restrictions due to the need to avoid unacceptable voltage conditions or system instability. These issues could be handled either by completing ex ante voltage and stability analysis and representing the calculated limits as thermal constraints, or with a more complex model which considers thermal, voltage and stability issues together.

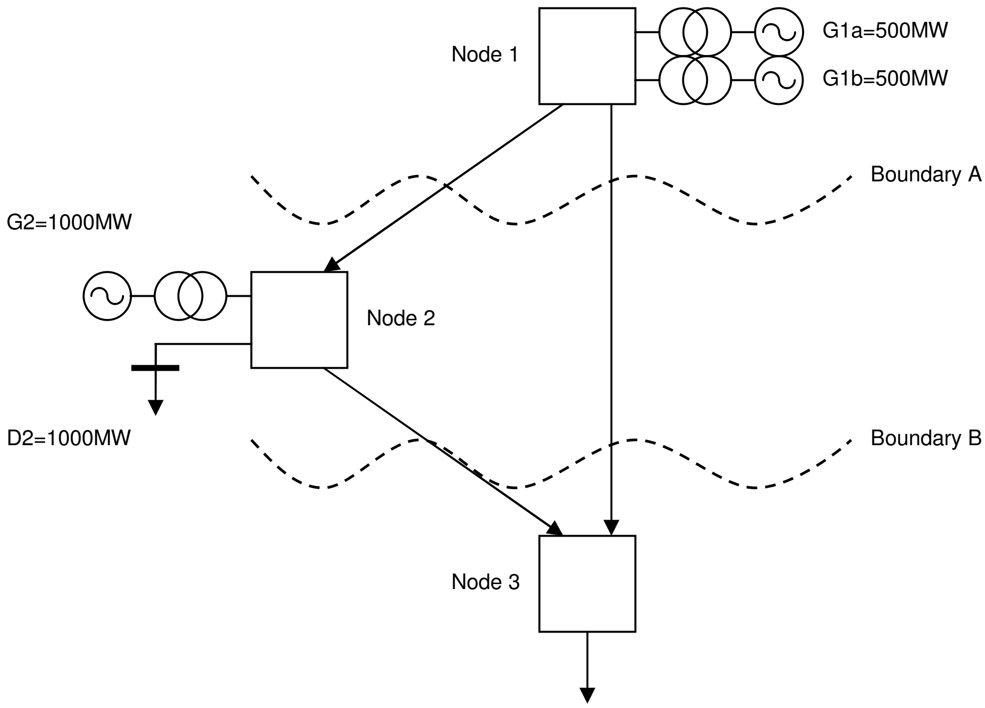
4.1.6.15 With the load-flow approach, it is essential that whilst transmission capacity in exporting parts of the network is limited to the circuit capabilities (plus the winter peak demand in that part of the network), capacity in importing parts of the network should not be constrained. In order to ensure this is the case, a ‘slack’ node which handles the difference between generation and demand such that the load flow model is soluble, would be required in an importing area of the transmission network. In order to avoid the location of the slack node influencing the outcome of the auction, it may be necessary to optimise across several loadflow models with the ‘slack’ node in different positions. This solution would be more accurate in circumstances in which the demands for access rights in the auction are dramatically different from those anticipated. This multiple loadflow approach would further complicate this approach.

4.1.6.16 The main disadvantage of the load-flow approach, even without voltage and stability restrictions being modelled, is the lack of transparency for Users which may adversely impact on price discovery. This approach essentially auctions capacity at all the nodes in parallel, taking into account all the complicated interactions between nodes simultaneously. Given the number of nodes on the system, understanding these interactions will be complex for Users.

4.1.6.17 The complexity is better illustrated in Figure 2, below. In this example, the two generators connected at node 1 (G1a and G1b) are competing for transmission capacity between nodes 1 and 3 with an expectation that the transmission access rights will go to the highest bidder. However, if we assume that the transmission circuit between nodes 1 and 3 has a much higher capability than that between nodes 1 and 2, then the capability between nodes 1 and 3 is dependent on the success in the auction of the generator connected at node 2 (G2). If this generator is successful, then it will balance the demand connected at node 2 (D2) such that the majority of the export from node 1 utilises the high capability line between nodes 1 and 3 giving a high transfer capability. If this generator is unsuccessful, there is no generation to balance the demand at node 2 and the majority of the export from node 1 utilises the lower capability line between nodes 1 and 2 giving a lower transfer capability. G1a and G1b think they are competing for a certain transfer capability only to find that this is no longer the case due to the success (or otherwise) of G2.

4.1.6.18 The load-flow approach is weighted towards accuracy of modelling the system at the expense of transparency for the User. There will be many interactions between nodes on the system and so it will be difficult for participants to interpret the price signals provided to them by the auctions. It was not clear to the majority of the group that this model would result in an efficient allocation of access rights due to the complexity of the approach.

Figure 2: Interaction between transfer capability and connected generation example



Boundary Constraint Model

4.1.6.19 The boundary constraint model was developed by the Working Group to provide a compromise between the zonal model with its simplicity but inaccuracies and the full nodal load-flow model which is more accurate but is complex for Users to understand. In the boundary constraint model, an ex ante load-flow analysis is performed to determine prevailing system power flows and boundary capabilities.

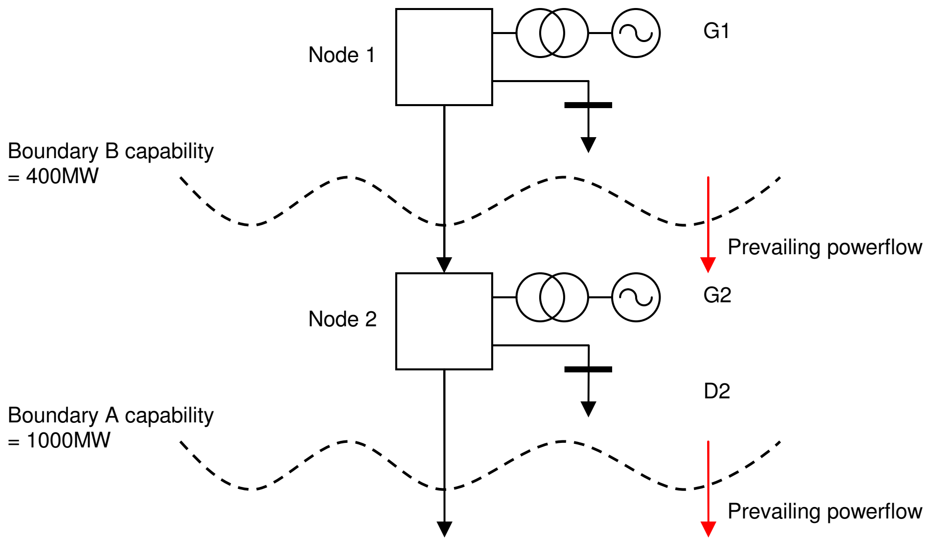
4.1.6.20 This ex ante analysis will involve scaling existing generation on the exporting side of system boundaries upwards until boundary constraints are revealed.

4.1.6.21 The prevailing power flows are used to link the access rights allocated in particular areas and the associated boundary flows. Using this approach, a set of more straightforward constraint conditions can be derived and these can then be used in an optimisation which seeks to maximise bid revenue.

4.1.6.22 It is worth noting that this approach also avoids the issues associated with a slack node described above.

4.1.6.23 This approach deals naturally with the problem of nested boundaries as illustrated in Figure 3 below.

Figure 3: Simple optimisation constraints



4.1.6.24 The optimisation constraints for the section of network above are:

$$(G1 - D1) \leq Boundary\ B\ capability$$

$$([G1 + G2] - [D1 + D2]) \leq Boundary\ A\ capability$$

4.1.6.25 With this approach the long-term transmission entry capacity will be allocated to the highest bidders up to the transmission boundary capabilities by discovering the value that all Users behind particular boundary constraints place on transmission access.

4.1.6.26 The simple example in figure 3 above assumes that each generator has an equal impact on the boundary. The appropriateness of this assumption will depend to a degree on the number of boundaries used in the model. A simple model of the boundary constraint auction approach has been developed using the SYS zones which has 17 boundaries. This will result in some approximations and further work is being carried out to identify a suitable number of boundaries. The initial result of this analysis of boundaries is included in Annex 3 to this document however. It should be noted that if the number of boundary constraints is too large, then the problems of complexity for Users identified in the load-flow model will also apply in this model. The key to this model is therefore in finding a suitable compromise between transparency for Users and accuracy of modelling.

4.1.6.27 The simple example above assumes that the boundary capacity is not impacted by the pattern of generation accepted in the auction. However, the example of Figure 2 above demonstrated that there are situations in which the generation impacts on the boundary capacity. The simplest approach to this issue is for the GBSO to perform analysis ex ante to establish reasonable boundary capabilities. The accuracy of this approach would ultimately depend upon the number of boundaries that are used (i.e. the more boundaries, the more accurate).

4.1.6.28 In order to achieve this, assumptions would have to be made about the potential success in the auction of generators that interact with boundary capabilities (G2 in the figure 2 example above). The issue with this approach is the importance of these assumptions. If they are wrong then the auction will either under-allocate transmission access rights, meaning that generation that could be accommodated would not be successful, or over-allocate transmission access rights, meaning that constraint costs will be higher than they would otherwise have been.

4.1.6.29 It should be noted that to some extent this problem exists today, although this is due to the closure uncertainty associated with a rolling transmission access right rather than the access allocation process. All Users are included in the contracted background which is used as the basis of the transmission network analysis performed when assessing the reinforcement works required to accommodate new generation connections. If some of these generators, the presence of which were effectively providing additional transmission capacity, were to leave the transmission system, with as little as five days notice, capacity would have been over-allocated and additional constraint costs would be incurred.

4.1.6.30 In addition, the value that generation in certain locations on the transmission system brings, in terms of allowing other generation to connect, would not be reflected. This is likely to mean that this generation is less likely to be successful in the auction, contributing to the risk of over-allocation described above.

4.1.6.31 The further approach discussed for the issue of interaction between generation and boundary capability is to perform analysis ex ante to establish boundary capabilities and participation factors to reflect the impact that connected generators have on the boundary capability. For the figure 2 example above, generators G1a and G1b would be given participation factors of 100% for boundary A (i.e. each MW accepted at G1a or G1b requires a MW of capability on boundary A) whereas generator G2 could be given a negative participation factor for boundary A (i.e. a participation factor of -10% would mean that each MW accepted at G2 would increase the capability of boundary A by 0.1MW). The advantage of this approach is the increased accuracy achieved by reflecting the impact that generators at different locations have on system boundary capabilities. It should be noted that the accuracy of this approach depends on how sensitive the participation factors are to the location of generation. Assumptions will need to be made about the location of generation in the ex ante loadflow analysis. If the auction results in generation in very different locations being awarded capacity, then the participation factors may no longer be valid. It is therefore important that sufficient sensitivity analysis is performed ex ante to avoid this issue. In terms of transparency, different participation factors for different generators are likely to make it more difficult for bidders to understand the competition for boundary capability.

Discussion of Appropriate Network Model

4.1.6.32 The Working Group discussed the relative merits of each of the network models in terms of accuracy and simplicity.

4.1.6.33 The zonal model was recognised as most transparent of the auction models. However it ignores the complex interactions between nodes once the volume in each zone has been set. The results were therefore deemed to rely too heavily on the initial assumptions made by the GBSO when allocating the initial capacity between zones.

4.1.6.34 It was recognised that the load-flow approach provided more accuracy as all calculations are carried out during allocation. However, there were concerns among the group that it would be extremely complex for generators to participate in the auction; any benefit due to increased accuracy of modelling is likely to be reduced due to the inability of participants to interpret the pricing signals from the model.

4.1.6.35 The view of the Working Group was that the boundary constraint approach provided the best compromise between accuracy of modelling and transparency for Users. However, it should be noted that there has only been limited testing of a simplified model with SYS 17 boundaries. The testing to date has demonstrated that the simplified model generally works as expected. However, the issue of nested boundaries means that it can be difficult for participants to understand what is limiting their ability to obtain capacity and therefore how much they need to bid. This will be complicated further as the number of constraint boundaries increases. At this stage there is not yet a firm view on the number of boundaries that will be required in the model although Annex 3 contains details of initial boundary analysis for all regions of Great Britain with the exception of the London area. It is only with testing of the full model that an assessment of the transparency of the auction for participants can be assessed.

<u>Baseline and Incremental capacity</u>

4.1.6.36 The auction will need to allocate baseline (existing) transmission capacity (MW) and incremental (new) transmission capacity (MW). The Working Group considered the following options for dealing with baseline and incremental capacity:

- Treat baseline and incremental capacity in separate auctions
  Separate auctions for baseline and incremental capacity may simplify the auction process and make it more transparent for Users. In particular, this would mean that any test that would need to be met for the release of incremental capacity could apply to the incremental capacity auction only. The main problems with this treatment are:
    - The interaction between baseline and incremental capacity
      In order to ensure that the separate baseline and incremental capacity auctions give an efficient solution, spare capacity from the baseline capacity auction would need to be reflected in the incremental capacity auction. This additional complexity may mean that the transparency and simplicity benefits of separate auctions for baseline and incremental capacity are lost.
    - Uncertainty for Users
      Separate treatment would mean that Users may need to book capacity in both auctions. This introduces additional uncertainty for Users that may only want the capacity that is allocated to them in the baseline capacity auction if they are also successful in the incremental capacity auction.
- Treat baseline and incremental capacity in the same auction
  A single auction for baseline and incremental capacity would address the interaction and uncertainty issues described above for separate auctions, but would be more complex and therefore less transparent.

4.1.6.37 Given the advantages and disadvantages described above, the Working Group concluded that baseline and incremental capacity would need to be treated together in the same auction.

Definition of Baseline Capacity

4.1.6.38 The Working Group agreed that quantity of baseline long-term access rights that are released by the auction will have a fundamental effect on the way that the transmission system is operated for many years to come.

4.1.6.39 In order to understand the options available for the definition of the baseline capacity on the transmission system and the associated consequences, an understanding of the planning criteria contained in the SQSS (http://www.nationalgrid.com/uk/Electricity/Codes/gbsqsscode/DocLibrary/) is required.

4.1.6.40 The current SQSS contains both generation connection and main interconnected transmission system planning criteria. The generation connection planning criteria contain limits to loss of power infeed and also consider a generator at 100% of its output and ensure that there are no unacceptable conditions for the loss of any two transmission circuits, so-called “n-2” criteria.

4.1.6.41 The main interconnected transmission system criteria apply to wider transmission system boundaries, where wider transmission boundaries are defined as those which split the transmission system into two zones, the smaller of which contains a demand of 1500MW or more. A planned transfer condition is established using one of the following techniques:

- Straight scaling technique – All generators on the system at the time of average cold spell (“acs”) peak demand are considered contributory and their output is calculated by scaling such that the aggregate level of generation is equal to acs peak demand;
- Ranking order technique – In circumstances in which the plant margin exceeds 20%, the ranking order technique will be applied in addition to the straight scaling technique. This maintains the output of generators that are considered more likely to operate at times of acs peak demand at more realistic levels and treats those less likely to operate as non-contributory (e.g. Open Cycle Gas Turbines).

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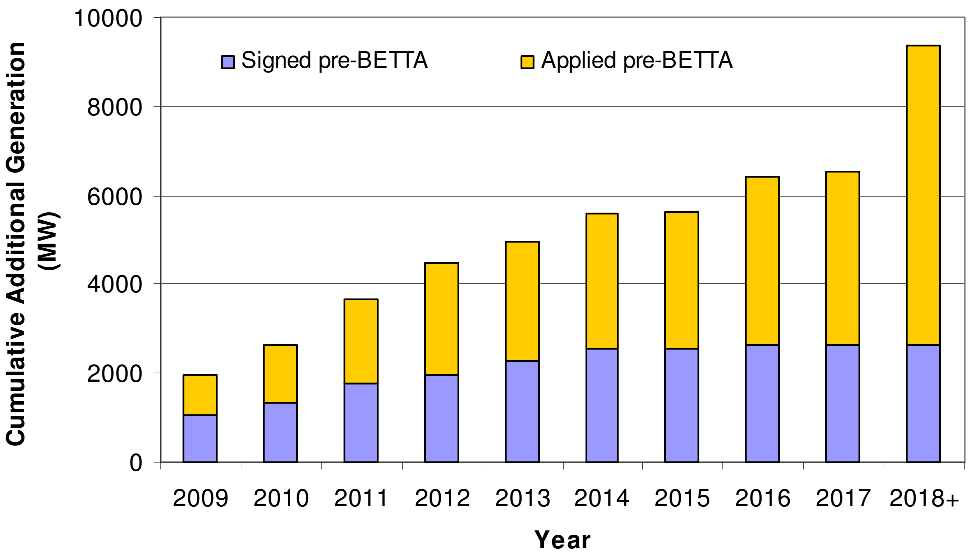
4.1.6.42 A safety margin (or Interconnection Allowance) is added to the power flows of the planned transfer condition to take account of non-average conditions (e.g. power station availability, weather and demand) and again analysis is performed to ensure that there are no unacceptable conditions for the loss of any two transmission circuits.

4.1.6.43 This essentially means that capacity on wider transmission system boundaries is over-allocated due to an implicit assumption that access rights will be shared.

4.1.6.44 The Working Group tested an illustrative boundary constraint auction and found that the generation connection criteria and main interconnected transmission system criteria could be modelled.

4.1.6.45 The Working Group noted that at BETTA, the decision was taken to treat connection applications received from Users in Scotland prior to a deadline such that their connections were not contingent on transmission reinforcements on the circuits between Scotland and England or on any other transmission reinforcements in England and Wales. This led to a further over-allocation of long-term transmission access rights in Scotland. This is currently handled with a derogation against the requirements of the SQSS for the boundary between Scotland and England. The Working Group agreed that, if necessary, this could be reflected by artificially increasing the capability of derogated transmission system boundaries in a boundary constraint auction.

4.1.6.46 The Working Group discussed the treatment of the boundary between Scotland and England in further detail. Analysis showing the amount of generation which had signed connection agreements or applied for connection before BETTA was considered. The expected build up of this additional generation is shown in the following chart.

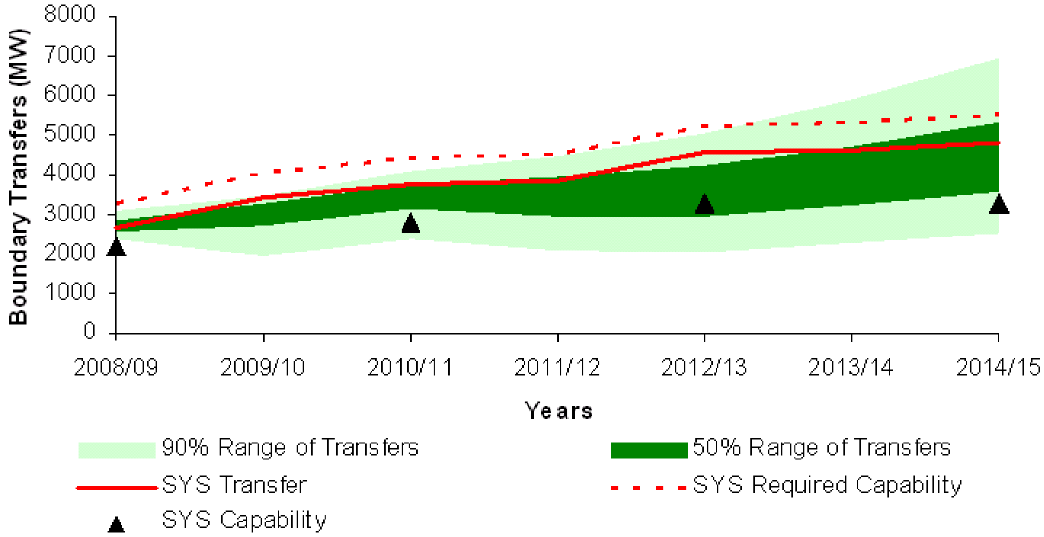


4.1.6.47 This analysis shows that nearly 10GW of projects over and above a 2008 capacity baseline which signed or applied for connection before BETTA could connect in Scotland after 2008. Since this generation applied before BETTA, under the current arrangements it can be connected without taking into account works which may be required on the boundary between England and Scotland or any other works in England and Wales. The Working Group agreed that the over-allocation of long-term access rights to this extent would be unworkable, and that alternatives would need to be considered.

4.1.6.48 The Working Group also noted that although the Cheviot boundary is currently over-allocated the growth in generation in Scotland may ultimately result in there being a requirement to over-allocate boundaries in England and Wales as the additional flows from generation in Scotland and newly connecting generation in England and Wales that is subject to similar BETTA planning background as the plant in Scotland connects.

4.1.6.49 The Working Group requested further detail on the extent of the over-allocation across the Cheviot boundary, both now and into the future. Complete details for the Cheviot boundary together with the other SYS planning boundaries may be found in the Seven Year Statement – Chapter 8. The SYS data for the Cheviot (SYS Boundary B6) is shown below:

Figure 8.B6 Boundary Transfers and Capability
Boundary 6: SPT to NGET



B6	SPT - NGET (EXPORT)	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
	SYS Transfer	2643	3413	3759	3862	4556	4616	4813
	SYS Capability	2200	2200	2800	3300	3300	3300	3300

4.1.6.50 As can be seen in the above SYS data the SYS Transfer (solid red line) across the B6 boundary is expected to grow to reach 3862MW in 2011/12 (the year upon which the first year and subsequent auction "over-allocated" baseline would be fixed). This would represent an "over-allocation" of ~500MW based upon the expected physical boundary capability of the boundary.

4.1.6.51 The Working Group also considered situations in which generation plant characteristics have influenced the design of the transmission system (e.g. the use of short-term cable ratings for generation with limited running time like pumped storage). The Working Group agreed that this could be modelled by scaling the impact that different generation technologies have on transmission boundaries in a boundary constraint auction.

4.1.6.52 The Working Group noted that whilst this approach appears appropriate for access allocation, it may be problematic if these generators (e.g. pumped storage) were to seek to share their transmission access rights with Users with different generation plant characteristics. The Working Group agreed that this would be an issue for sharing within pre-defined zones with a 1-1 exchange rate, but that with the alternative node to node sharing arrangements, any exchange rate provided by the System Operator could be used to manage the issue of different generation technologies (provided these generators are connected at different nodes).

4.1.6.53 The Working Group noted that the approach to allocating transmission capacity and triggering reinforcement in an auction would need to be based on the relevant SQSS criteria, but also that if the short-term transmission access developments described in CAP161, CAP162 and CAP163 are approved, then it may no longer be appropriate for capacity on main transmission boundaries to be over-allocated. Since Users are able to choose to share access, buy short-term access from the GBSO or overrun their aggregate holding of long and short-term access rights, over-allocating transmission access rights behind export constraints may cause an inefficient increase in socialised constraint costs.

4.1.6.54 If the SQSS is revised in line with these assumptions, then it may be more appropriate to allocate physical boundary capacity in an auction. Users would essentially choose the appropriate SQSS scaling for their generation type by their choice between the long-term access rights allocated by the auction and the short-term access rights provided by CAP161, CAP162 and CAP163.

4.1.6.55 In light of the above, the Working Group considered the following options for the definition of baseline transmission access capacity:

- **Consistent with the current long-term transmission access rights**
  This option would be consistent with the current SQSS planning criteria, but with an over-allocation in Scotland. Given the extent of over-allocation of long-term access rights in Scotland, the Working Group agreed that the baseline capacity of the Scotland to England boundary should be limited to a level sufficient to accommodate those in a position to take part in the first annual auction and to purchase capacity from year 1 onwards – i.e. capacity will be allocated to any successful bidder who has an LCN Effective Date earlier than 1st April T+1, assuming that the first auction allocates capacity from Year T onwards. Any unsold baseline capacity as a result of this condition would not roll forward to future annual auctions.
  The Working Group also noted that the use of a reserve price may allow for a larger baseline capacity to be used for the Scotland to England boundary and would allow the operational costs (if any) caused by this larger baseline to be targeted to those that caused them, and this is discussed further below. Other Working Group members noted that a larger baseline could still be allocated without a reserve price, and the operational costs of this (if any) could be socialised as is the case currently.
- **Strictly consistent with the current SQSS**
  This option would be more strictly consistent with the current SQSS planning criteria such that the aggregate level of long-term access rights available in Scotland would be lower than is currently the case.
- **Consistent with physical boundary capability at peak demand**
  For exporting zones/boundaries, long-term access rights would only be released up to physical zonal/boundary capabilities, with the assumption that sharing of transmission access rights will be provided by the short-term access and sharing arrangements contained in CAP161, CAP162 and CAP163.

4.1.6.56 The Working Group also discussed the stability of the baseline capabilities and the importance of this given the decisions made by Users between long-term and short-term transmission access. The Working Group agreed that baseline capabilities would need to be consistent across all the years for which capacity is sold in a particular auction, but that they could change auction by auction. The Working Group also agreed that whilst baseline capabilities may change auction by auction, that long-term wider entry rights purchased by Users would be financially firm.

4.1.6.57 The Working Group discussed the impact of baseline capability changes on Users choosing between long and short term wider entry rights. The Working Group discussed an example in which a particular User chooses short-term access rights because they see a high baseline capability. If this capability was then revised downwards the following year, then this User is exposed to a significant increase in the short-term price of transmission access. The Working Group agreed that it is appropriate that this is a risk associated with choosing short-term (instead of long-term) wider entry access rights.

4.1.6.58 The Working Group discussed the circumstances by which baseline capabilities may change from year to year. For larger boundaries or zones, the capability will be limited by particular circuits and therefore the location of generation will interact with the baseline capability (if generation is closer to the limiting circuits, then the baseline capability will be lower). Where the location of generation that results from an auction is very different from that assumed in any ex ante network analysis used to calculate baseline capability, then it may be necessary to revise the baseline capability for the next auction.

<u>Incremental capacity</u>

4.1.6.59 In order to release incremental capacity, the GBSO needs to ensure that the bids received in the auction are sufficient to trigger an investment in long-term transmission assets. In order to achieve this, a ‘hurdle’ test is envisaged in which the cost of the reinforcement to the transmission system is compared to the value of the additional bids that could be accepted if that reinforcement is constructed. If a participant obtains capacity at a price above the supply function for incremental transmission capacity then the reinforcement is triggered. The supply function for incremental transmission capacity indicates to the Users the cost that would need to be met from incremental capacity bids in order to trigger the release of incremental capacity.

4.1.6.60 The Working Group agreed that a methodology for deriving the supply function for incremental transmission capacity would be required and this has not been developed at this stage. The Working Group did, however, discuss the principles that would underpin the derivation of the supply function, including:

- Constraints;
- Risk sharing;
- Multiple years;
- Complexity.

4.1.6.61 The Working Group considered appropriate constraints on the supply function for incremental transmission capacity and the following options have been considered:

4.1.6.62 Option 1: Assume that incremental capacity is unconstrained after [4] years

4.1.6.63 This approach is similar to that used in the gas Quarterly System Entry Capacity (QSEC) auctions. The provision of incremental capacity is assumed to be unconstrained after 42 months, although National Grid NTS (as the Gas transmission system operator and owner) has the ability to "play" permits to flex this period back or forward on each system entry point (and the playing of these permits is incentivised).

4.1.6.64 This approach would be suitable if the User commitment associated with bidding for transmission access capacity in the auction means that fewer projects seek transmission access rights than is currently the case, to the extent that all of these projects can be accommodated within the [4] year period

4.1.6.65 If this is not the case, and demand for transmission access rights continues to be in excess of supply of those rights, then this approach would lead to an over-allocation of long-term entry transmission rights and the associated inefficient operational costs.

4.1.6.66 Option 2: Model the constraints that exist on the delivery of incremental capacity

4.1.6.67 The current queue for long-term entry access rights on the transmission system suggests that transmission access is likely to be constrained for an extended period (the queue stretches out beyond 2020 in some locations). Given this, it may be more appropriate to model the constraints that exist in the provision of incremental capacity. This has the following advantages over the unconstrained approach for circumstances in which the demand for incremental long-term entry access rights is in excess of supply:

- Long-term entry access rights are not over-allocated and therefore inefficient increases in operational costs are avoided;
- The transmission rights available are allocated to those that value them most.

4.1.6.68 Given the issues listed above, the Working Group agreed that the supply function for incremental transmission capacity should include the constraints that exist on the delivery of incremental capacity.

4.1.6.69 The supply function for incremental transmission capacity would need to be set to take account of the appropriate risk sharing between generators and all Users. The Working Group agreed that the supply function should be set to 50% of the cost of the associated transmission reinforcement to achieve consistency with the gas regime and the previous work completed for CAP131 and CAP165.

4.1.6.70 The Working Group noted that in order to trigger incremental capacity, the comparison of the price Users are prepared to pay, and the supply function for incremental transmission capacity would need to look across multiple years.

4.1.6.71 The following options to handle multiple-years have been considered:

- Option A: Treat all years together

4.1.6.72 Users could submit a schedule of volumes and bid prices for a number of future years, and these could all be treated together.

4.1.6.73 Whilst this may be manageable for a relatively simple auction, it becomes a complex problem for a nodal loadflow or boundary constraint (with many boundaries) auction.

4.1.6.74 The advantage of this approach is that the baseline capability is automatically the same in each year.

- Option B: Separate auctions for blocks of years

4.1.6.75 This option is based on giving precedence to those Users that are willing to commit to access rights in the longer-term in order to simplify the auction process and introduce greater transparency.

4.1.6.76 The GBSO would first host an auction for a long-term block of access rights, say [10] years (in whole financial years). Users would specify the start date, volume and bid price for each year. It is essential that Users are able to profile bid prices between different years because of the likelihood that there will be more competition for access rights in some years rather than others. Access would be allocated to those that value these rights the most.

4.1.6.77 Once this auction has closed, the GBSO would then host an identical auction, but for a short-term term block of access rights, say [5] years. This auction would be conducted with all rights allocated by the [10] year auction included in the baseline (i.e. the baseline would be reduced by any access rights allocated in the [10] year auction).

4.1.6.78 Once this [5] year auction is closed, the System Operator would finally host an auction for access rights in individual years. Again, this auction would be conducted with all rights allocated in the [10] and [5] year auctions included in the baseline.

4.1.6.79 The main issues with this approach are:

- The precedence given to those Users that are willing to commit to transmission access rights in the longer term may lead to an inefficient solution
- Users with ageing power station assets may only want capacity for a limited number of years. If they do not participate in the auctions for [10] year or [5] year block of capacity then there may be no baseline capacity remaining for them to bid for. If they'd have been willing to bid more for these limited number of years than those generators that were allocated baseline capacity in the [10] year and [5] year auction, then the outcome will not be efficient.

- The treatment of incremental capacity; without a different treatment for incremental capacity, Users bidding for transmission capacity in the [10] year auction may not trigger incremental capacity, whereas if the [10] year and [5] year blocks of capacity were auctioned together then this would have been the case due to the increased demand for transmission access rights in certain years. This issue could be addressed by holding separate auctions for baseline and incremental capacity, although this brings other issues as described above. The auction for incremental capacity would need to consider all bids for transmission capacity simultaneously, which means that some of the simplicity and transparency of this option would be lost.

o Option C: Separate treatment for each year

4.1.6.80 Separate auctions would be held (simultaneously) for each year. Incremental capacity would initially be triggered in an individual year if the additional bid revenue that could be accepted in that year is greater than the associated supply function for incremental transmission capacity. In order to derive the supply function, the cost of transmission reinforcement (as modified to reflect the appropriate risk sharing arrangement, i.e. 50%) would need to be annuitised . The results from each year would then be summarised between rounds. Incremental capacity would be released if:

- o It is triggered in at least [8] individual years, since this represents a recovery of [50%] of the capital cost at regulated rates of return; or
- o It is triggered in less than [8] years but the net present value of the additional bid revenue as a result of the transmission system reinforcement across all years is greater than 50% of the capital cost of the reinforcement.

4.1.6.81 The incremental capacity that is triggered would be re-entered into the auctions for individual years. The separate auctions would then be repeated and the results published prior to the next auction round.

4.1.6.82 An illustrative example of this approach is described below.

4.1.6.83 If the capital cost of a transmission zone or boundary reinforcement is £70000/MW, then the annuitised value is £4600/MW (assuming an annuitisation factor of 15.22 as per paragraph 3.5.1.4 which is based on an asset life of 50 years and a regulated rate of return of 6.25%).

4.1.6.84 If this reinforcement is triggered in [8] individual years then the total revenue recovered will be at least [8×£4600/MW=] £36780/MW which is approximately 50% of the capital cost.

4.1.6.85 If the reinforcement is triggered in less than [8] years, then a net present value test will be applied as shown in the example below.

	2012	2013	2014	2015	2016	Total
Additional bid revenue [capacity of reinforcement × price[8]]	£11000	£11000	£11000	£11000	0	£36390
50% Reinforcement cost	£35000	0	0	0	0	£35000

[8] This would be the relevant price; the options are described under Pricing below

4.1.6.86 In this illustrative example, the reinforcement is only triggered in [4] individual years, but the net present value of the additional bid revenue is greater than 50% of the capital cost of the reinforcement, and therefore the reinforcement would be triggered.

4.1.6.87 This approach is easier to implement than the option of treating all years together, but it is not as accurate since bids in any particular year are disregarded unless they are greater than the annuitised reinforcement cost. This may mean that reinforcements are not triggered when they would have been under a strict net present value approach.

4.1.6.88 The main issue with this approach is that Users may require long-term transmission access rights over a number of years, but may be successful in some years and unsuccessful in others. A dynamic auction design may provide a solution to this issue, and this is discussed further below.

4.1.6.89 The other issue with this approach is that it reduces the transparency of the auction. It is more difficult for Users to understand the incremental capacity that is triggered in individual years because these investments are triggered over multiple years.

4.1.6.90 The Working Group also discussed the complexity of the supply function for incremental transmission capacity. This included consideration of the following options:

- Marginal £/MW function with constraints (e.g. £3000/MW up to 1000MW);
- Marginal function with multiple £/MW bands (e.g. £3000/MW up to 500MW; £4000/MW between 500MW and 1000MW, etc.)

4.1.6.91 The Working Group noted the interaction between the supply function for incremental transmission capacity and any reserve price (if applicable). The Working Group discussed the use of a reserve price derived from the Investment Cost Related Pricing Transport and Tariff model currently used to derive TNUoS tariffs. Since this methodology seeks to calculate the costs of incremental investment, this could be used to derive both the applicable reserve price in addition to the supply function for incremental investment to provide consistency and transparency for auction participants.

4.1.6.92 Finally, the Working Group discussed the treatment of planned schemes to increase transmission capability in the transition period from the current arrangements. The Working Group questioned whether:

- these schemes should progress, with the incremental capacity delivered included in the baseline capacity for the appropriate year; or
- these schemes should be used to derive the incremental capacity supply function and only progressed if triggered by the auction process.

4.1.6.93 The Working Group agreed that whilst inclusion in the baseline would ensure the timely delivery of incremental capacity, there was a risk that the need for this investment is not justified by the subsequent auction results, leading to the potential for stranded investment. The Working Group also noted the Transmission Owner revenue implications of the two options and the importance of alignment with Transmission Owner Price Control arrangements.

<u>Pricing</u>

4.1.6.94 The pricing options considered for a long-term entry capacity auctions are:

- Pay as bid

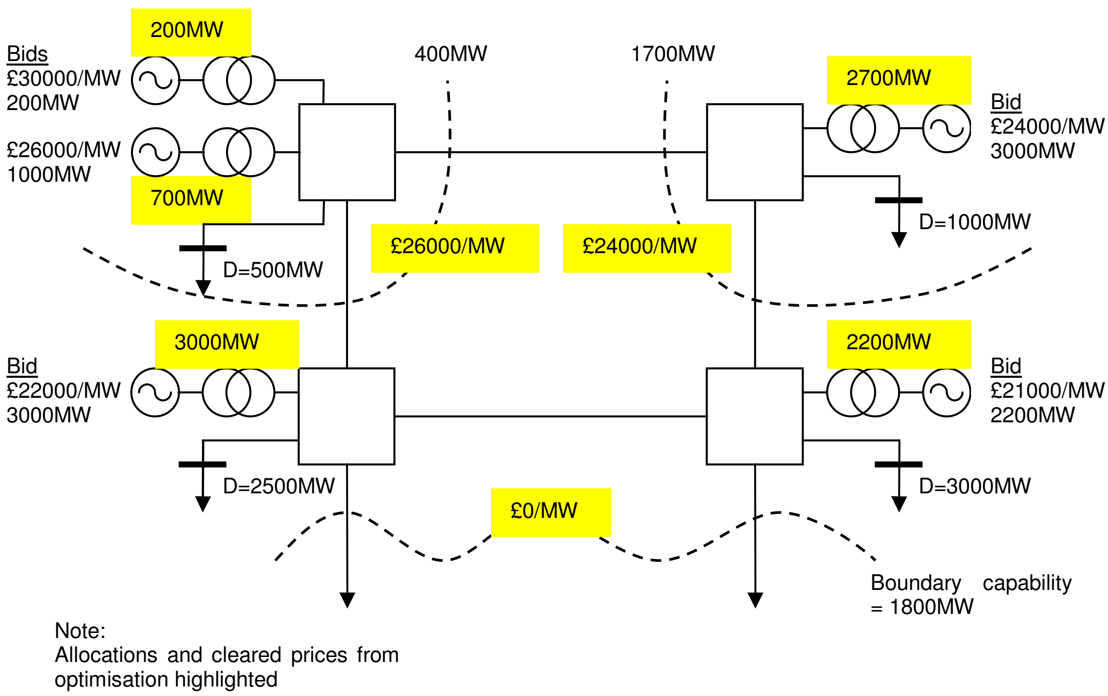
4.1.6.95 Users that are successful in the auction are committed to pay the price they bid.

4.1.6.96 The issue with this approach is that it could lead to Users paying different prices for the same service.

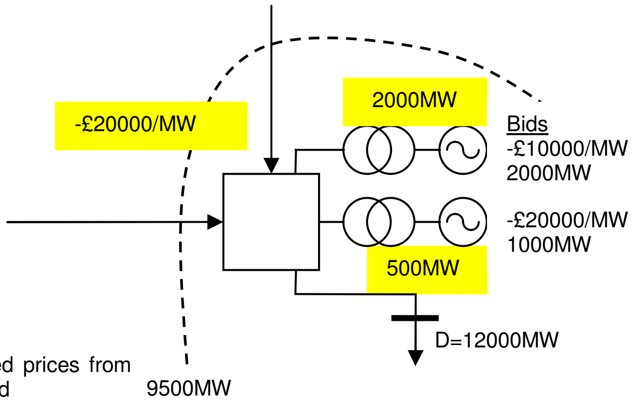
- Cleared (or marginal) price

4.1.6.97 Users that are successful in the auction pay the cleared or marginal price. This is essentially the price of the last successful bid to be accepted. This means, in a positive zone with three bids for 100MW each of £1000, £5000 and £10000 that (if there is 300MW of available transmission access capacity) all three bidders will receive their chosen capacity but all would pay £1000 only. However, if there was only 200MW of capacity available then only the £5000 and £10000 bids would be successful (with both paying £5000) and the unsuccessful £1000 bid would receive no long term transmission access in the auction. The situation is the same in importing zones in which the demand is higher than the boundary capability where, if you reverse the prices (and there were 300MW available) all three would get capacity and be paid -£10000 each. However, if there was only 200MW of capacity available then only the -£1000 and -£5000 bids would be successful (and would be paid -£5000 each) and the -£10000 bid would receive no long term transmission access in the auction. In an auction for zonal capacity, the cleared (or marginal) price is simply the price at which the demand for access rights is met by supply. In a nodal loadflow or boundary constraint auction for capacity, this price depends upon the boundaries that constrain the optimisation solution. In order to illustrate this further, some examples are shown diagrammatically below.

Cleared (or marginal) pricing: Exporting example



4.1.6.98 As described in section 2.16, the main issue with a cleared price is that auction participants only receive a cleared price above zero when there is competition for capacity. This is a significant departure from the current TNUoS charging arrangements which charge on a long-run marginal cost basis whether there is spare capacity or not.



Note:
Allocations and cleared prices from optimisation highlighted

4.1.6.99 Another issue with a cleared (or marginal) price is that although it ensures the same price for the same service, there are concerns that market power can lead to an inefficient allocation of capacity. This is due to the incentive to bid below true marginal price in order to decrease the price paid, which is especially important in the presence of market power as large players have a greater incentive to shade their bids. As these players are bidding for a greater quantity of transmission access rights, they can make greater savings. This may cause an inefficient allocation as large players win fewer rights than they should and small players win too many. Although this outcome may be inefficient, it is worth noting that small players benefit from the market power exercised by the larger players.

4.1.6.100 The Working Group noted that with a cleared price, incremental transmission capacity should only be triggered if the cleared price (rather than the bid price) is greater than the supply function for incremental transmission capacity.

4.1.6.101 The testing of the boundary constraint auction undertaken by the Working Group was based on incremental transmission capacity being triggered when the bid price (rather than the cleared price) being greater than the supply function for incremental transmission capacity, and therefore further work would be required to develop the boundary constraint auction if a cleared price is to be used.

4.1.6.102 Whilst a cleared price ensures that Users that bid in the same auction would pay the same price for the same service, the Working Group noted that Users in the next auction may pay a different cleared price. Some Working Group members were concerned that this may represent discriminatory treatment of different generators based on their ability to participate in a particular auction.

4.1.6.103 The appropriate arrangements for the recovery of the difference between the auction revenue and the Transmission Licensees Maximum Allowed Revenue will be the subject of a TNUoS Charging Methodology Modification Pre-consultation.

Reserve Price

4.1.6.104 The requirement for a reserve price interacts with the other auction design considerations discussed. An auction without a reserve price can arguably send locational signals to Users for incremental capacity, since this capacity will only be released by the transmission companies if the additional bid revenue exceeds the cost of the incremental capacity (or a proportion of the cost as discussed above). However, an auction with no reserve price will not send locational signals to Users based on the cost of using existing assets, which in the long-term will have to be replaced.

4.1.6.105 It is also worth noting that without a reserve price, generators could essentially secure long-term baseline capacity at a price which is below the Long-Run Marginal Cost (LRMC). This has the following consequences:

- Users that come along in the future that are willing to pay a higher price may have to wait for incremental capacity to be constructed. Ensuring that all Users pay the LRMC by setting a reserve price for baseline capacity does not solve this problem, but it does at least minimise it.
- It may be difficult for Transmission Licensees to justify the retention for wayleaves for transmission lines in circumstances in which the Users of those lines are not willing to pay the LRMC.
- There are likely to be significant changes to revenue recovery, which will impact on the residual charge.

4.1.6.106 This is also an issue in parts of the transmission system which are currently assigned a negative TNUoS tariff.

4.1.6.107 In an importing part of the transmission network (one in which demand > generation), the transmission system may be reliant on generation to meet demand without causing any unacceptable overloading of the boundary circuits. For a nodal loadflow or boundary constraint model, generation which is sited in these parts of the network could submit negative bids. These bids would be accepted if they result in a lower cost than would be required to reinforce the associated boundary.

4.1.6.108 Whilst this results in an efficient outcome in the years in which transmission reinforcement could be completed, for those years in which reinforcement could not be completed to time, the generator could potentially submit an excessive negative bid which would have to be accepted to ensure transmission system security.

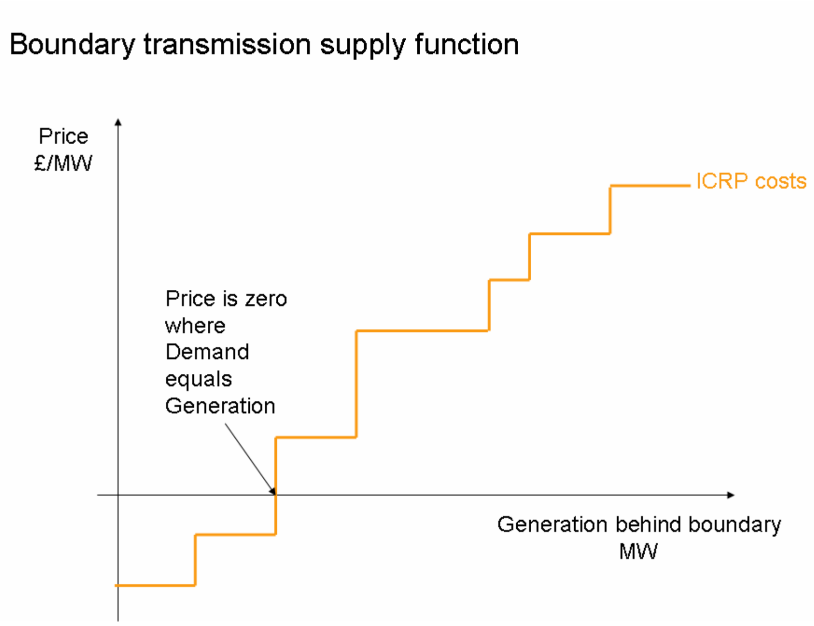
4.1.6.109 In order to prevent this situation arising, it may be worthwhile to consider collaring negative bids at zero or the long-run marginal cost (LRMC) for the area. The LRMC could be calculated by the Investment Cost Related Pricing (ICRP) transport and tariff model, although the input assumptions would have to be clarified.

4.1.6.110 In terms of modelling this in a nodal loadflow or boundary constraint model, this could be achieved by introducing a ‘dummy’ generator priced at the LRMC collar (e.g. -£8500) that would effectively compete with the generators in that area. If generators submitted better bids (e.g. -£8490) then the optimisation would accept them whereas if generators submitted worse bids (e.g. -£8510) then the optimisation would accept the dummy generator in order to honour the boundary constraint. The generation that was actually needed in real time to prevent an unacceptable overloading of the boundary circuits would then be required to procure short-term access.

4.1.6.111 In light of the issues highlighted above, the Working Group considered the implementation of a reserve price to maintain the long-term locational cost signals that currently exist.

4.1.6.112 In order to achieve this, the ICRP transport and tariff model would be used to calculate the reserve price. This could be a zonal reserve price, or could be mapped to boundaries (e.g. for use with the boundary constraint model). The Working Group discussed the following issues associated with calculating a reserve price with the ICRP transport and tariff model:

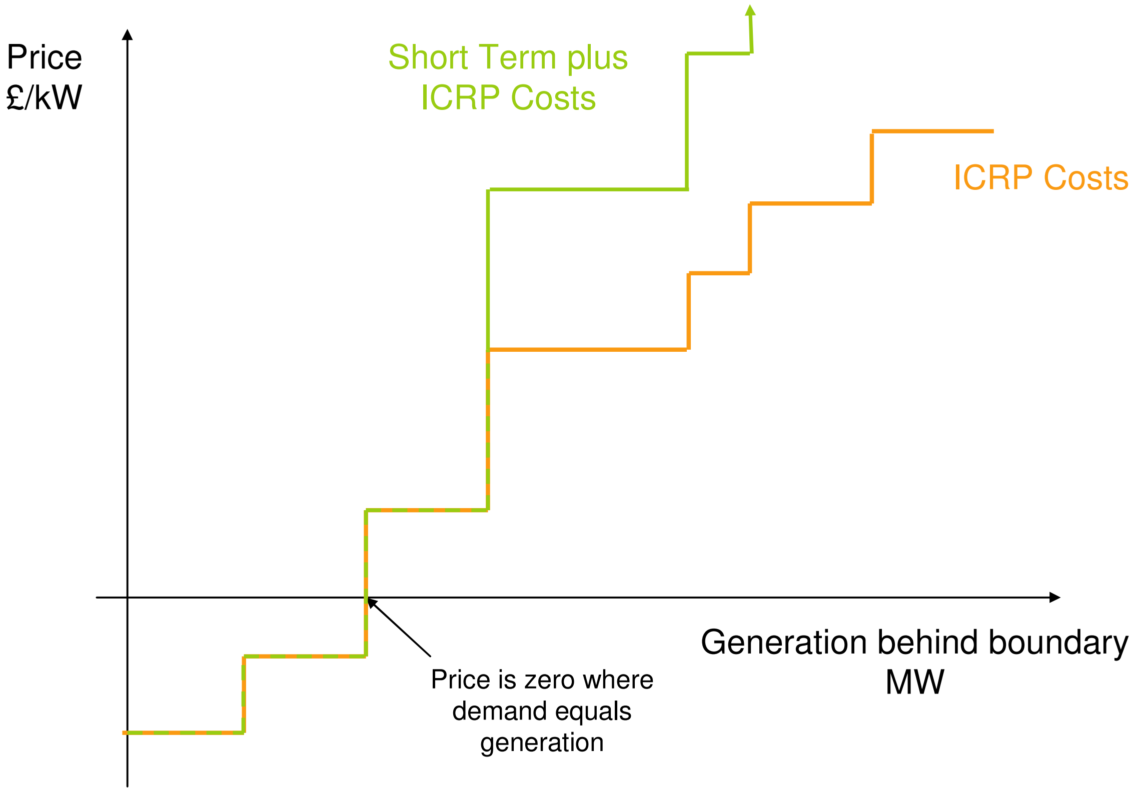
- Uncertainty in level/location of generation;
  Given the level of generation in a zone or behind a boundary is unknown at the time the reserve price is calculated, the Working Group considered the calculation of a reserve price function as shown in the illustrative example below.



  Where the generation behind a boundary is lower than the demand, the reserve price is negative, indicating that generation behind that boundary would reduce transmission costs in the long-term (fewer transmission assets would be needed to supply demand). Where the generation behind a boundary is higher than the demand, the reserve price is positive, indicating that additional generation behind that boundary would cause additional export and therefore additional transmission costs in the long-term.
- Future transmission network uncertainty;
  The associated costs of the reinforcements that are completed on the transmission system to provide incremental capacity will have a bearing on the associated reserve price.

4.1.6.113 The Working Group agreed that these issues would need to be addressed prior to the implementation of a reserve price based on the ICRP transport and tariff model. It was agreed that completing this work would involve a substantial amount of resource to complete. Views on which was the best governance framework under which to progress such work were heavily in favour of the CUSC governance framework being the most suitable. An alternative option of the Charging Methodology was put forward by National Grid as National Grid felt that though either governance framework could be used, keeping using Charging governance would avoid the need for the ICRP methodology to be duplicated in the CUSC. The clear majority of Working Group members continued to favour CUSC governance however.

4.1.6.114 The Working Group also discussed the application of a reserve price to the over-allocated boundary between Scotland and England. Given that the over-allocation of long-term access rights behind this boundary is leading to increased short-term (operational) costs, it was proposed that these costs could be added to the reserve price function. This would allow any expectation of future over-allocation to be honoured, but also ensure that Users that benefit from the over-allocation of long-term transmission rights pay a cost-reflective price – an example of this is shown below. Some Working Group members did not feel that this approach would be appropriate and that such costs could continue to be socialised across all Users. Other Working Group Members felt that the model may not be workable and without further analysis of the approach felt unable to support or oppose it.



4.1.6.115 It is noted that although the above analysis was looked at against the context of the currently over-allocated Cheviot (B6) boundary it was assumed that the methodology put forward above would equally apply to any other over-allocated boundary. However it is not the intention of National Grid to over-allocate any boundaries that are not currently over-allocated through a transmission access auction.

Static/dynamic

4.1.6.116 One of the main options in auction design is between a static or dynamic auction.

- In a static auction, there is only one round of bidding. This makes the process simple to administrate, but also means that bidders do not have the opportunity to refine their bidding strategy.
- In a dynamic auction, there is more than one round of bidding, and bidders have an opportunity to revise their bids based on the information revealed in the previous rounds of bidding.

A frequent motivation for the use of dynamic auctions is reducing common-value uncertainty, allowing bidders to bid more aggressively with less fear of 'winner's curse'.

The role of a dynamic auction in price discovery is also important. If there is little price information available, then it is difficult for bidders to know how to bid. By seeing tentative price information in the early rounds of bidding, bidders are more able to make decisions about bidding strategy, which increases allocation efficiency.

4.1.6.117 The Working Group considered that due to the immaturity of the secondary markets that are proposed for transmission access (the short-term arrangements described in CAP161, CAP162 and CAP163), avoiding winner's curse is an especially important consideration and therefore the Working Group unanimously supported the use of a dynamic auction (over a static auction) for CAP166.

4.1.6.118 The operation of a dynamic auction could be constrained by only allowing ascending (or descending) changes between auction rounds to the price, volume or duration of transmission access rights that Users are bidding for.

4.1.6.119 A dynamic auction would allow Users that are allocated transmission access rights that are lower than their minimum stable generation an opportunity to increase their bids to increase the rights allocated to them.

4.1.6.120 For the 'separate treatment of each year' approach described above, a dynamic auction would allow Users to increase their bids for any years in which they are unsuccessful.

4.1.6.121 The Working Group noted the importance of information provision between auction rounds to aid price discovery. The Working Group agreed that bid prices and volumes (MW) should be published together with access allocations (MW) and cleared prices for each individual year and details of the timing and volume (MW) of any transmission reinforcements that are triggered.

4.1.6.122 Some Working Group members expressed concerns about this level of transparency since it may lead to gaming by parties to ensure competitors pay a high price for capacity. The Working Group agreed that the majority of these concerns were addressed with the use of a cleared price auction, and that maximum transparency is the appropriate starting point. This can be reviewed when there is some experience of auction participants' behaviour. Some Working Group Members also noted that this issue would be further mitigated through more extensive testing and trialling processes. Other Working Group Members noted that there is also the ability of Ofgem to view the actions of Users in auctions and if it felt it to be appropriate investigate any behaviour that could be viewed as anti-competitive.

4.1.6.123 In the case of the transmission access rights allocated being lower than minimum stable generation or access rights not being allocated in particular years, if Users are unsuccessful in winning the necessary access rights by increasing their bids in further rounds then these Users may want the option to drop their bid prices or reduce their bid volumes for long-term access rights to avoid being committed to paying for a sub-optimal holding of transmission access rights. This implies that inappropriate constraints on changes to price, volume (MW) or duration between auction rounds would not be helpful.

4.1.6.124 Without any constraint on changes to price, volume (MW) or duration between auction rounds, the auction could potentially run for very many rounds as Users optimise their positions. In order to ensure that the auction closes, the following options were considered:

- a ‘clock’ auction;
- define stability criteria, such that the auction closes when these criteria are met;
- Introduce appropriate constraints on changes to price, volume (MW) or duration and define stability criteria.

4.1.6.125 The Working Group did not support a ‘clock’ auction because it would mean that the allocation of capacity would be reduced to a ‘fastest computer wins’ process, with Users not declaring their positions until the very last moment. The Working Group noted that an auction with a maximum number of rounds essentially collapses to a ‘clock’ auction unless there are other means by which the auction can close (e.g. stability criteria being met).

4.1.6.126 The Working Group considered that monitoring changes to allocation of capacity to Users between auction rounds could be used to establish appropriate stability criteria for a dynamic auction. As an example, the auction could be closed when there are no changes to transmission access right allocations between rounds of >10MW or no changes to the cleared prices between rounds of >£0.01/MW.

4.1.6.127 The Working Group developed the stability criteria based on cleared prices further. The cleared price associated with each boundary in each year would be monitored. Initially the Working Group considered that the auction would close if the cleared prices in all years and zones (or all but a small number) were identical in two successive rounds. Worked examples of these stability criteria showed that there were circumstances in which access allocations could change without the cleared price changing and therefore the Working Group agreed that the auction would close if the cleared prices in all years and zones (or all but a small number) were identical in three successive rounds. To aid auction participants, National Grid would notify Users if the stability criteria were met in two successive rounds to ensure that the auction would not close ahead of participants expectations.

4.1.6.128 The Working Group also agreed a mechanism whereby Generators would be able to set a "de-minimis" auction acceptance volume parameter that would limit the auction model from accepting a Bid from a Power Station if it was pro-rated or capped at a level below the de-minimis value specified. This would ensure that Generators would not be left with long-term transmission access allocations that due to the physical operating range of the Power Station would in practice be of little use to the Generator. It would also have the benefit that such transmission access would also be released to those more able to utilise it.

4.1.6.129 The Working Group discussed some testing of an illustrative auction model that was performed by National Grid. In these tests, players behind constraints would reduce their volume to 0MW when the cleared price got above a certain value. This volume reduction would cause the cleared price to collapse to zero (or the reserve price) in the next round and these players would increase their volume again in the next round. Under these circumstances, it does not appear to be appropriate to allow Users to increase their volume again from 0MW. If they did so, then the cleared price would increase again and since other Users were prepared to pay more than the User that dropped out in previous rounds, this would be the case in future rounds meaning that the auction is prolonged for no benefit. The Working Group noted that it may be appropriate to allow Users to increase their volume from 0MW in future rounds if more than one User behind the same binding constraint were to drop out in the same round.

<u>Summary of design options</u>

4.1.6.130 The table below summarises the design options, for the CAP166 auction, considered by the Working Group.

Design considerations	**Options**			
Network analysis	Zonal	Nodal loadflow	Boundary constraint	
Interaction between boundary capability and connected generation	Ex ante analysis	Ex post	Multiple boundaries	Participation factors
Baseline and incremental capacity	Separate		Together	
Definition of baseline capacity	Current long-term access rights (TEC)	Current GBSQSS	Revised GBSQSS	
Incremental capacity - Constraints	Unconstrained after [4] years		Constraints modelled	
Incremental capacity - Multiple years	Together	Blocks of years	Separate	
Incremental capacity - Planned schemes	Include in baseline		Include in derivation of incremental capacity supply function	
Pricing	Pay-as-bid		Cleared (or marginal) price	
Static/Dynamic	Static		Dynamic	
Reserve price	Based on LRMC		No reserve price	

4.1.7 Buy-Back Arrangements

4.1.7.1 When considering the appropriate arrangements to deal with the non-provision of access rights, it is important to consider the differences between the two access products being suggested by CAP166; LCN and wider transmission access rights.

4.1.7.2 For LCN, it is suggested that the remedy for non-provision of the required physical works should continue to apply as currently detailed for an existing local and wider connection application. This means that the Connection Agreement would specify the circumstances and the form of compensation payments which would be paid by National Grid if the TOs failed to deliver such assets. If the reason for a delay in the provision of such assets was due to any failure to comply by the generator concerned with any terms of the Connection Agreement, as is currently the case, no such compensation payment would be due in that instance.

4.1.7.3 For the wider transmission access product, if the access rights secured via the auction process are not able to be honoured, then the appropriate compensation should depend upon the reason for such failure.

4.1.7.4 If the reason for such failure is that the LCN was not completed (hence access to the wider system is not possible), then in addition to any failure to deliver payments applicable under the LCN process, it is suggested that National Grid should offer to buy-back the wider transmission access rights from the purchaser at the price originally paid in the auction. The User would of course be free to enter into any contractual arrangements with a third party to transfer such rights, but note that due to the limitations around the acquisition of wider transmission access rights, such a third party would need to hold appropriate LCN for the transfer to be possible. This effectively offers the User the opportunity of potentially recovering the value of its auction bids for wider access in addition to any payments due under the LCN process.

4.1.7.5 If the reason for failure to provide such wider transmission access rights is due to a constraint on the wider system itself, it is proposed that the existing Balancing Mechanism approach should continue. However, in the circumstances where there is limited competition in the provision of such constraint volumes (due for example to the location of a particular generator on the system), it may be appropriate for an administered price to be applied in these cases to avoid any abuse of market power. Some Working Group members disagreed with the principle of an administered price being applied and believed that any abuse of market power could be dealt with by the Authority.

4.1.7.6 Within the Working Group there was also a consideration of other high-level options to dealing with circumstances in which successful bids for incremental capacity are not honoured by the GBSO due to delays in the planning and/or construction phase. For the avoidance of doubt, where such a delay was due to the generator's failure to comply with the Connection Agreement then no buy-back would be made to that generator for so long as they failed to comply.

4.1.7.7 The further options considered are described below:

- Construction Agreements are used to manage the delivery of wider transmission works and User works. This is the situation which currently applies under the existing local and wider connection application process, but it is difficult to envisage how this could continue in the future as the two access products are effectively de-linked.

- Within the auction process, Users' bids would include both a bid price (£/MW) and an acceptable buy-back price (£/MWh). Whilst this option appears attractive to Users since it allows a particular User's acceptable buy-back price to be considered in the allocation process, it is difficult to develop a practical and transparent means of doing so without over-complicating the auction allocation process.
  The importance of the buy-back price submitted by the User in access allocation would depend on the GBSO's assessment of the risk that the incremental capacity would have to be bought back. A disadvantage of this approach is that it is not an easy task to undertake as it would necessitate the GBSO assigning ex-ante probabilities to such risks which may not be valid once the results of the allocation are known.

4.1.8 Balancing Services

4.1.8.1 The Working Group agreed that generators tendering for Balancing Services contracts would be responsible for purchasing the necessary transmission access rights, whether long-term or short-term, to meet those contractual requirements. Although Short-Term Operating Reserve contracts can be for as long as 2 years, Balancing Services in general are procured within year. This would give generators the option of using long- or short-term access products, and then tendering for such services. The exception to this would be MaxGen, which by definition is a product used to exceed transmission access rights holdings.

4.1.8.2 The Working Group discussed whether requirements for mandatory ancillary services would need to be removed from the Grid Code as a result of the implementation of a long-term entry capacity auction. The Working Group agreed that this would not be necessary since mandatory ancillary services only need to be provided when Users are generating.

4.1.8.3 Some Working Group members expressed concern that a generator may not have transmission access capacity at the point at which National Grid wishes to dispatch that generator. However, this may only be an issue if access rights holdings changed half hour on half hour, which would not be the case for capacity allocated under CAP166 (or, indeed, for any of the short-term products currently being developed). In any event, the generator would have the ability to specify its operational parameters to be reflective of the transmission access rights it held.

4.1.9 Testing of Auction Design

4.1.9.1 The group discussed in detail the importance of the design and testing of an auction. The literature emphasises that auctions (be they for a product a commodity or service) are only suitable for allocating a scare resource if they are well-designed and that one size fits all is a very bad principle in auction design. The Working Group were concerned that there has been no expert advice on the auction designs, given the dangers of unintended consequences.

4.1.9.2 The importance of testing was highlighted by the original proposal as described in section 3.8.3.2 above. A full design was developed and appeared suitable. However a five minute experiment by some Working Group members demonstrated that the design was fundamentally flawed and not suitable for allocating transmission access capacity.

Boundary constraint model testing

4.1.9.3 A simple version of the boundary constraint model was developed towards the end of the Working Group process to aid understanding of the auction model. This model was based on the SYS zones and had 17 boundaries. The model was developed in a very short time scale and has not been thoroughly tested. However, initial testing produced results as expected.

4.1.9.4 Testing with the model identified the issue that the current TNUoS approach and the auction could provide very different pricing signals. This issue was particularly notable in zones which are currently assigned a negative TNUoS tariff. In these zones, an increase in generation would, in the long run, reduce the overall cost of transmission. Generators in these zones currently receive a TNUoS payment. However this is not necessarily the case with the boundary constraint auction. A generator in a zone would only receive a payment if the total flow across boundaries into the zone could not meet the demand in that zone. The generator is required to meet demand and can therefore charge a scarcity price. All other generators in zones which currently have a negative TNUoS tariff would need to submit positive bid prices in order to gain long-term access rights.

4.1.9.5 Testing of this 17 boundary model for a single year also highlighted transparency issues caused by the nested nature of the boundaries which made it quite difficult for participants to understand what bid was required to obtain capacity.

4.1.9.6 In order to investigate the transparency of these arrangements for Users, the Working Group tested a simple model which included multiple boundaries.

4.1.9.7 Given that the boundary constraint model is based on an optimisation which seeks to maximise bid revenue minus reinforcement cost, the Working Group interpreted this to mean that provided the clearing price on the exporting side of a boundary was greater than the incremental capacity supply function then reinforcement of the boundary would be triggered.

4.1.9.8 The Working Group found that, whilst this was the case with no other constrained boundaries, other constrained boundaries interacted such that reinforcements are only triggered if the cleared price differential across a boundary is greater than the supply function.

4.1.9.9 The complexity of participating in an auction with more boundaries for a number of years is likely to be much greater. The degree of complexity will only be understood by testing a full auction model, but this has not been possible in the time provided to the group. However, the majority of the group were of the view that any auction model is likely to favour large participants who have significant analytical capability.

4.1.10 Non-Physical Players

4.1.10.1 Under the current (CUSC) arrangements, only physical parties; ie generators; can apply for Transmission Entry Capacity (TEC). Transmission access arrangements are codified in the Connection and Use of System Code (CUSC). Currently Interconnector Users and Suppliers are non-physical signatories of the CUSC, but these Users do not hold TEC. For holders of TEC, the CUSC is ingrained with technical obligations which Users with transmission entry access rights must fulfil (because such rights are implicitly linked to physical generation equipment). To allow non-physical parties to obtain (and then trade) transmission access a new category of non-physical User would need to be included, and the CUSC would need to be rewritten to separate access rights from Users' obligations.

4.1.10.2 One member of the Working Group questioned whether it would be permissible under the Acts of Parliament associated with the CUSC to change it to include non-physical players. They noted that if during the progression of the NETA and BETTA related legislation (which (i) introduced the CUSC and (ii) amended it) DTI/BERR, Ministers, the Government, or Parliament had opined on non-physical players then this might preclude what was being proposed. It was decided to seek a legal view on this from BERR. The group voiced concern that waiting for the answer could hold up the work of the group. However, it was noted that the work of the group could proceed and a response on this matter be provided (i) to the group or (ii) the CUSC Panel in due course.

4.1.10.3 For the avoidance of doubt, the Working Group agreed that if CAP166 were to include the ability for non-physical parties to obtain (and then trade) transmission access that this would be an Alternative (as this was not part of the (original) CAP166, as proposed by National Grid. The Working Group is not proposing, at this stage, that such an Alternative be developed. However, it would welcome views on this as part of this consultation.

4.1.10.4 Under a recent CUSC amendment, CAP150, a power station should be able to demonstrate the capability of delivering MW output equivalent to their requested (MW) TEC transmission access figure. CAP150 was brought in to avoid network investment in excess of the capability of generation assets. Non-physical players by definition would not be able to demonstrate this capability without an agreement with a physical party.

4.1.10.5 There is concern in the group that allowing non-physical parties to buy transmission access rights could lead to poor transmission investment signals. Under the current arrangements as a power company builds their power station the risk of them not connecting reduces as the assets are put in place. Often the investment in transmission assets for a new power station goes hand in hand with the power station assets being built. If transmission infrastructure is built to accommodate a purely financial commitment the revenue for the assets would be recovered (from the non-physical party who made the booking that caused the transmission investment) but the infrastructure may remain unused.

4.1.10.6 The group believed it would be difficult for the TO's to build assets to reinforce a zone without knowing specifically where a generator would be based as well as the associated technical aspects of that generator. Some Working Group members suggested that the transmission system boundaries could be reinforced in this case, although this may not be the most appropriate investment, depending on who the eventual (physical) party was that used the rights.

4.1.10.7 Some members of the Working Group voiced concern that adding a third party into the trading of transmission access rights may increase the transactional costs. Such non-physical parties would also be aiming to make money through the trading of transmission access capacity, which would be likely to increase the overall cost to the electricity consumer.

4.1.10.8 The main aim of including non-physical players in the market would be to improve liquidity, and to address the concern that to exclude them would be to limit market activity. Non-physical participation is permitted in other markets, such as gas, though new capacity has to be booked at a certain point not in the form of deep reinforcement. However, the focus for the development of transmission access arrangements is to facilitate the more efficient use of the electricity transmission system. The group considered that it should aim to do this in the least complex manner and that creating a new commodity market should not be an aim in itself.

4.1.10.9 Therefore, given the additional complexity that would result from the inclusion of non-physical participants, the group believed that significant benefits would need to be demonstrated in order to justify such a move. Further, some members of the group considered that introducing non-physical players would not actually improve the liquidity of the market. There is also some concern in the group that allowing non-physical players to participate would increase the potential for gaming.

4.1.10.10 One member of the group argued that the exclusion of non-physical parties in the proposed long-term electricity access arrangements is discriminatory and against the spirit of a liberalised competitive market. However, it was pointed out by other members of the Working Group that the exclusion of non-physical parties has been a feature of the CUSC since it was designated by the Secretary of State in 2001 (and again in 2005) following consultations by Ofgem and (DTI)BERR.

4.1.10.11 Some members of the group considered that allowing all (physical and non physical) parties to participate in transmission access arrangements, improves competition and liquidity for capacity so that where there is a scarce resource, a useful investment signal is developed. Different capabilities may facilitate the entry to the market of new players particularly if they are small in size and cannot handle the risk associated with transmission access. Also, the generation market becomes more competitive as a variety of contractual forms are allowed to exist. For example, tolling arrangements and optimisation for merchant plants where capacity is managed by the “off-taker” who may very well be a “non-physical” player.

4.1.10.12 One member argued that some of the financial transmission rights markets in the US also permit non-physical players to participate. The reason for that is exactly that financial players, if subject to the same collateral and anti-hording requirements as the rest of the market participants, can bring additional liquidity to the market and offer risk management services to smaller participants that may not have the same capability.

4.1.10.13 A Working Group member considered the discussion on gaming is also overplayed. Capacity speculation within transmission networks is not viable when there are appropriate anti-hoarding measures in place, and in any case there can be no provision on which class of market player may trade purely on a speculative basis. The Working Group member added, on the other hand no legislation can prevent non-physical players acting on the capacity market through a physical player and a "sleeve" arrangement. Taking as an example the UK Gas Market, abusive squeezes in the gas capacity market have not worked as capacity simply becomes free for those that can physically utilise it.

4.1.10.14 The majority of the group concluded that including non-physical players in the transmission access arrangements would provide liquidity advantages. However, in order to do so it would be essential that appropriate anti hoarding measures were put in place to avoid market abuse. Short term access arrangements could provide anti hording measures by ensuring that unused capacity was made available for free in the short term markets. Some Users would want to buy long-term transmission access rights as a hedge against the short term price of access.

4.1.10.15 The group believe that it may be necessary to have a Licence for non-physical Users. To include non-physical players would also involve changes to the CUSC. The group; mindful of the need for (i) anti hoarding measures and (ii) the fair trading of capacity; considered that arrangements similar to those applied to Users of inter-connector would need to be put in place if non-physical players were to be granted long term transmission access rights.

4.1.10.16 The majority of the Working Group believes that whilst non-physical player could provide some benefits it was not practical at this stage to include them in the proposed CAP166 amendment. It is considered that whilst the inclusion of non-physical players should not be taken forward as part of this amendment it would be a positive extension to the access arrangements at a future date.

4.1.11 TO/SO Interaction

4.1.11.1 One of the points to consider of moving to an auction framework will be the interaction between the actions of the TOs and the SO. If incremental capacity is signalled on the system then revenue for provision of such incremental capacity is assumed to be provided to the TOs under the provisions of their respective Transmission licences. This may be through the Regulated Asset Base (RAB) if the incremental capacity has already been factored into the baseline obligations or via the revenue driver provisions if the baseline is assumed to be flat.

4.1.11.2 However, constraints on the system could occur for two different reasons:

- the decision by the SO to provide incremental capacity by contractual means or by essentially 'run the system harder'; or
- the decision by one of the TOs not to invest on the system.

4.1.11.3 An appropriate set of complementary incentive arrangements will need to be developed such that there are the correct incentives on the various parties involved such that both the TOs and the SO can make informed choices as to how to provide such incremental capacity.

4.1.12 Governance including Auction Methodology Statements

4.1.12.1 The Working Group discussed the appropriate governance arrangements for the auction.

4.1.12.2 The Working Group proposed the establishment of a suite of methodology documents under the CUSC. These methodology documents would include, for example, baseline definition and supply function for incremental transmission capacity. It is envisaged that changes to the methodology could be proposed in accordance with the established CUSC amendments process.

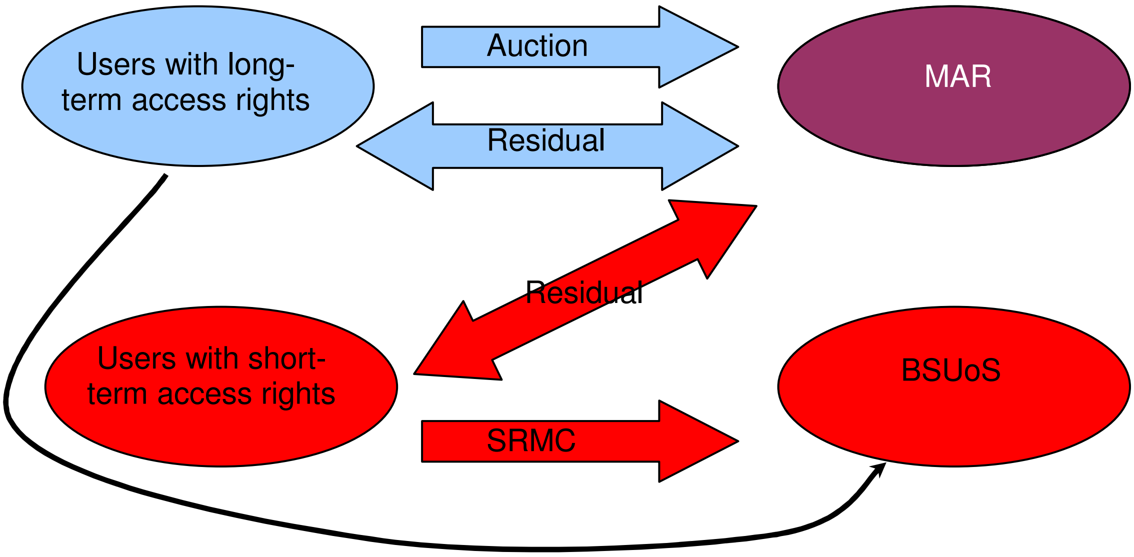
4.1.12.3 National Grid presented to the Working Group a draft of a "SO Long Term Release Methodology Statement", the purpose of which is to provide a description of the mechanism by which National Grid would offer TEC for sale via the Long-Term auction process. It also describes the methodology that National Grid would use to determine whether to release incremental capacity to Users, and the levels of financial commitment required from such Users to underpin such a release. It was largely based on the existing process which is followed as part of the long-term auctions for Entry Capacity in Gas.

4.1.12.4 The following items are included within the draft SO Long-Term Release Methodology Statement. The complete document may be found attached to this Working Group Report at Annex 8.

- Purpose of the Methodology Statement
- Summary of the methodology underlying the Auction Process
- Auction process – Introduction and the product being offered for sale
- Annual Invitation Process
- Annual Auction Application Process
- Stability of the Annual Auction Application Process
- Annual Auction Allocation Process
- Annual Auction Information Process
- Incremental Release Methodology – Decision Making Applied
- Procedure for allocating incremental annual TEC
- [The methodology by which the Reserve Price is calculated behind each boundary]
- Simple example of allocating incremental annual TEC (single year and multi year examples)

4.1.13 Revenue Recovery

4.1.13.1 The group considered that it was appropriate for Users buying both long-term and short-term access products to pay for their use of the transmission network. This would be paid for through the generation residual by all Generators.



Should a Reserve Price for the price of Long-Term Access rights exist and contain an element reflecting the short-run costs of over-allocating long-term access, the revenue from this element will be offset against BSUoS

4.1.13.2 Since the residual would be used to recover the remainder of the maximum allowed revenue after an auction, the amount of money which needs to be recovered through the residual is dependent on the amount of revenue recovered from the auction. The revenue recovered from the auction could over or under recover MAR. This means that the residual could be either positive or negative. It was further noted by the Working Group that in auction models without a reserve price there was potential for no or little revenue to be collected through the auction in certain years and that in such cases the share of National Grid's Maximum Allowable Revenue (MAR) paid by Generators (27%) would be entirely recovered through the generational residual tariff.

4.1.13.3 The Working Group considered if it was appropriate for Users with short-term access to pay (or be paid) a generation residual which could be heavily influenced by the long-term capacity auction. The Working Group noted that the allocation in the long-term auction would affect the price of short-term products. If the auction over recovered that would mean there was much competition for access. This would lead to the short term products being expensive. If the auction under recovered it would mean there was less competition for long-term access and therefore in general the short-term access products would be cheaper. However to remove the linkage between Short-Term Access and the residual TNUoS tariff would mean that Short-Term Access Users would not be contributing to the long-run costs of the transmission system which some Working Group Members also felt was inappropriate.

4.1.13.4 The group concluded that if Users with short-term access were expected to pay the generation residual when the auction under recovers, it is equitable for short-term Users to be paid the generation residual if the auction over recovers. Further consideration of how the residual will be charged under will be considered through the charging governance.

4.1.13.5 There was also a short discussion by the Working Group of the most appropriate revenue recovery mechanism in auctions with reserve prices, specifically where the Reserve Price reflects the short-run marginal costs caused by an over-allocation of long-term access rights. A number of Working Group members believed that it would be appropriate to ring-fence such revenues from the auction that reflect these short-run costs and to offset them against the BSUoS charges. There was insufficient time available to the Working Group to properly assess the most appropriate means of performing this offset however with views being split between whether the revenue would be most appropriately offset on a £/MW basis or a £/MWh basis.

4.1.13.6 The eventual conclusion was that the total revenue should be offset against the total BSUoS bill, effectively meaning that a fixed sum would be subtracted from each half hour of BSUoS revenues across the whole year. This approach was adopted for pragmatic reasons due to lack of assessment time and not because a majority of Working Group members felt it to be the most appropriate.

4.1.13.7 One final observation was made with regard to the revenues from auctions in response to concerns of Working Group members who felt that due to the demand for transmission access the revenues from auctions could see a significant "over-recovery" of revenue when compared to the existing revenue from locational generation TNUoS charges (~£50million) and perhaps could exceed the ~£330million of revenue (27% of MAR) collected from generation in total TNUoS charges. It was noted however that regardless of how much revenue resulted from the auction, Generators as a group would never pay revenue in excess of 27% of MAR. In the extreme case where more than 27% of MAR was recovered by the auction the residual tariff would become negative to compensate.

4.1.14 Impact of Price Based Auction on TNUoS Charging

4.1.14.1 It is important to note at this stage that the principles underlying allocating capacity via an auction of the type described are very different from those of the present TNUoS methodology. An auction (of the type described by the original amendment, WGAA1 and WGAA2) therefore provides very different price signals to participants compared to the current TNUoS charging methodology. This issue was only identified by the majority of the Working Group late in the process and so there has been little discussion within the group on this important topic. The major differences between the TNUoS and auction approaches will now be described.

4.1.14.2 The current TNUoS charging methodology recovers the cost of the existing network and provides locational signals for new capacity. TNUoS essentially charges for both existing and new capacity on a long-run marginal cost basis. At a given node the impact of an incremental MW of capacity on the MWkm of the network is calculated. For a generator in the south the MWkm of the network is likely to reduce as flows from Scotland are reduced. This reduction in MWkm is reflected in a negative charge for the southern generator. Conversely, an incremental MW of capacity in Scotland will increase the MWkm of the network and this is reflected in a positive TNUoS charge in Scotland.

4.1.14.3 Unlike TNUoS, a capacity auction without reserve prices is not designed with the intention of recovering network costs. The auction is aimed to fulfil two primary functions. Firstly, in a system where capacity is constrained, it provides a method of allocating this scarce capacity. Secondly, it provides a mechanism for participants to signal their desire for new capacity by bidding at a level which triggers investment.

4.1.14.4 The significant difference between the two methodologies can best be understood by considering a network where new capacity is only allocated following the completion of the necessary transmission reinforcements (which results in no entry capacity constraints). Under the current TNUoS methodology generators in the north will be charged for capacity whereas generators in the south will be paid. The remaining costs of the system are recovered through the residual payment which is charged on a £/KW basis.

4.1.14.5 Conversely, an auction without reserve prices will only charge participants for capacity when there is competition for that capacity. Under the unconstrained situation described above there is adequate capacity for all generators. In the absence of a reserve price, participants could bid zero in the auction and will receive their requested amount of capacity. In this situation the cost of the network attributed to generation (27% of the total transmission allowed revenue) would be recovered through the residual charge.

4.1.14.6 The primary difference in the two approaches is in the treatment of the current network. The TNUoS methodology and an auction with reserve prices linked to Long-Run Marginal Costs charges for the existing network on a Long-Run Marginal Cost basis whereas the auction without reserve prices considers the cost of the current network to be a sunk cost. It only derives an income from the current network when capacity is scarce.

4.1.14.7 This may have a significant impact on revenue recovery, particularly in the early years of an auction in which only the existing connected generators are in a position to bid for access rights and all zones (or boundaries) are unconstrained because the transmission system has been designed to accommodate all of these generators.

4.1.14.8 It is also worth noting a second difference between the two approaches. Under the auction regime, depending on the timing of auction participation, two adjacent generators can be charged very different amounts for what is essentially the same capacity product. Consider a situation where generator A is already on the system and is able to participate in the initial auction. If generator A is successful in the auction for 5 years it will pay the cleared price in that auction for the 5 years' worth of capacity. Generator B is located adjacent to A but was not completed in time to compete in the initial auction. Generator B competes in the auction 1 year later and successfully obtains capacity for 4 years at the cleared price of that auction. This cleared price in the second auction could be very different from that in the first auction. This contrasts with the current TNUoS methodology, which due to the fact that it is a prevailing charge, all generators in the same location would be charged the same cost for capacity.

4.1.15 Interconnectors

4.1.15.1 The Working Group noted that interconnector owners would have to bid for long-term wider entry access rights, but may have a different appetite for risk than interconnector Users.

4.1.16 Interaction with other Modifications

4.1.16.1 The Working Group noted that the following CUSC amendment proposals could be implemented with CAP166 in order to provide a flexible short-term access regime:

- CAP161: SO release of short-term access rights;
- CAP162: Entry capacity overrun;
- CAP163: Entry capacity sharing.

4.2 Working Group discussions during extension – Capacity and Duration Auctions

The following section summarises the discussions which took place in the Working Group during the eight weeks extension where the focus was on development of a capacity and duration based auction model.

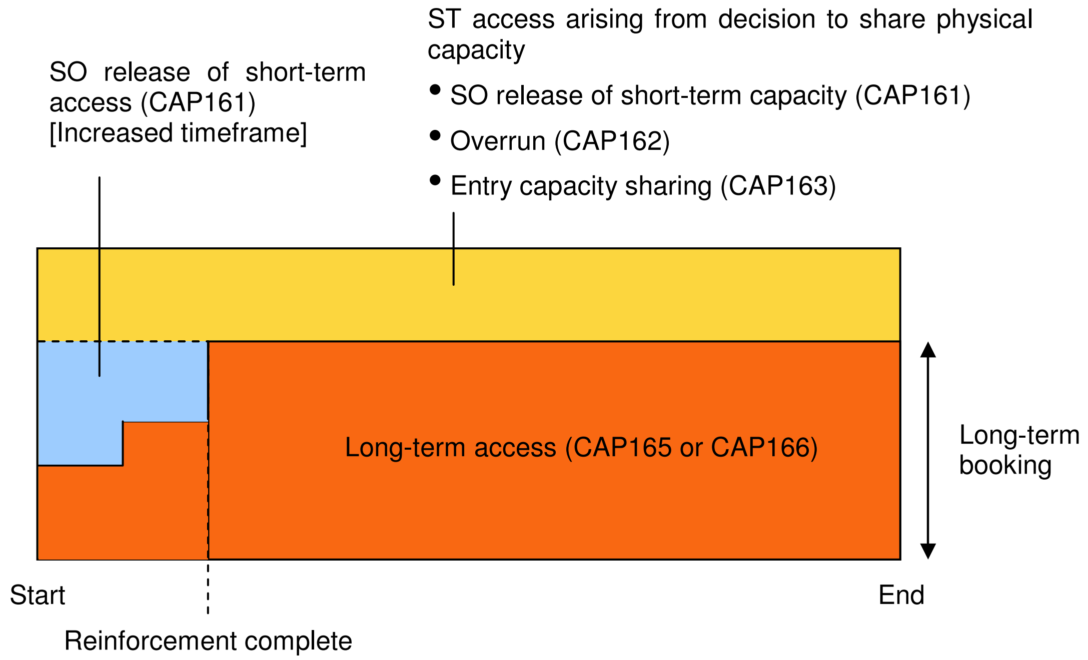
This type of auction differs fundamentally from a price based auction in that the System Operator no longer publishes the availability of capacity in each year of the auction to the market. In this instance, Users bid their capacity requirements and their requirements are allocated in full but at a price which is calculated as a combination of a long-run price (taking into account the physical capability of the network) and at a short-run price for access rights above that physical capability.

4.2.1 Discovering the appropriate level of transmission investment

4.2.1.1 The Working Group discussed how the signals received from an auction for long-term transmission access could be used to determine the appropriate level of transmission investment. The following is based on the time period after which the TOs would be able to respond to any signals to provide investment on the GB transmission system, rather than in the intervening period when a potential 'over-allocation' of rights could exist.

4.2.1.2 The Working Group noted that long-term access rights provide Users with a perfect hedge against the short-term price of transmission access at a stable price. The main means of providing this hedge is to invest in transmission capacity and minimise the short-term price of transmission access.

4.2.1.3 In order to understand this issue further, the Working Group considered the full range of "raw" transmission access products potentially available. These are shown in the diagram below.



4.2.1.4 The Working Group then compared the following scenarios:

Scenario One: User makes derivatives from raw products

4.2.1.5 Under this scenario, Users would take a view as to the level of long-term access rights they require based on their intended operating regime and knowledge of the short-term and long-term access prices. Users would then only bid for the level of long-term rights they required in the auction, using other access products available to provide the required level of short-term access rights.

4.2.1.6 Long-term access rights would be defined by a capacity limit only and would be fully shareable and tradable up to that capacity level.

4.2.1.7 The System Operator would be obliged to provide the level of long-term access rights booked at a stable long-term asset based price (e.g.TNUoS) and the User would be required to face the short-term access price (by utilising short-term access products or sharing transmission capacity) for output above this level. Given that the long-term access right is based on a capacity limit only and is fully shareable and tradeable up to that level, all Users would be liable to pay equivalent charges regardless of the use they made of those capacity rights.

4.2.1.8 It should be noted that if there is a time-lag between the required start date for the long-term access right and the delivery of the necessary transmission reinforcements then, in the period from the start of the access right to the delivery of the necessary transmission capacity, the User will be liable to pay a forecast of the short-term access cost (similar to the SO release of short-term access arrangements covered in CAP161, but potentially over a longer time period).

4.2.1.9 The Working Group envisaged that the System Operator would be incentivised to minimise operational and investment costs such that long-term access rights are provided at the minimum cost.

4.2.1.10 The Working Group discussed the example of a 100MW wind generator in Northern Scotland. The long-term access price (TNUoS) is £21.59/kW (2007/08 prices) and the short-term access price was assumed to be £65/MWh when there is a constraint (currently estimated at 15% of the year) and £0/MWh when there is no constraint. If the load duration of the generator is as follows:

Output level	Proportion of year
0%	0%
20%	50%
40%	20%
60%	15%
80%	10%
100%	5%

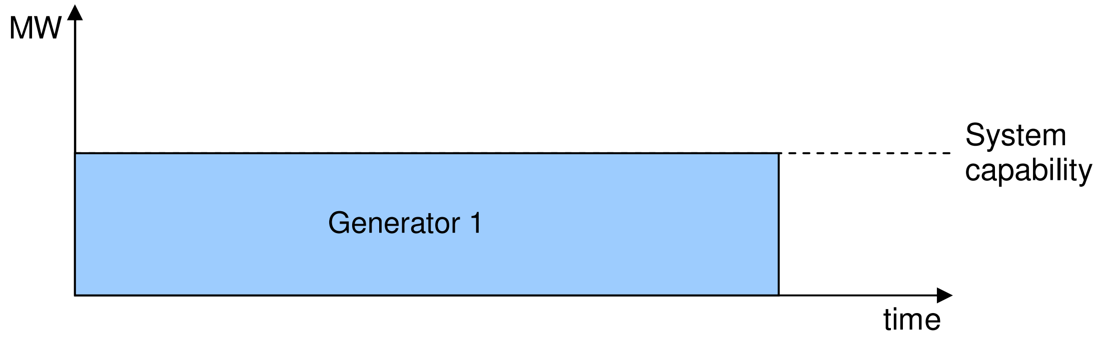
4.2.1.11 The generator could decide to book his full requirement as long-term rights in which case the full 100 MW would attract the TNUoS based charge. Alternatively, he could decide to book less as long-term and then secure his remaining rights on a short-term basis. The following provides a comparison of the potential costs of the various options available to the generator.

- Book 100MW of long-term access rights
  Annual access price = 100MW×1000×£21.59/kW = £2.159m
- Book 80MW of long-term access rights (and secure remaining 20MW as short-term)
  Long-term access price = 80MW×1000×£21.59/kW = £1.727m
  Short-term access price = 5%×15%×8760hours×20MW×£65/MWh = £85.41k (in a range £0 to £569.4k when correlation with other generators is considered)
  Total annual access price = £1.727m + £85k = £1.812m (in a range £1.727m to £2.296m)
- Book 60MW of long-term access rights (and secure remaining 40MW as short-term)
  Long-term access price = 60MW×1000×£21.59/kW = £1.295m
  Short-term access price =[5%×15%×8760hours×40MW×£65/MWh] + [10%×15%×8760hours×20MW×£65/MWh] = £341.6k (in a range £0 to £2.278m)
  Total annual access price = £1.295m + £341.6k = £1.637m (in a range £1.295m to £3.573m)

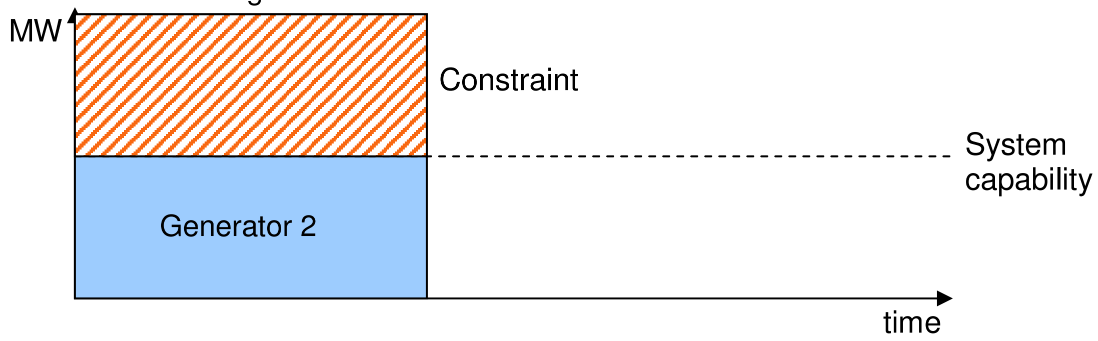
Scenario Two: SO makes derivatives from raw products based on additional information provided by the bidder

4.2.1.12 Under this scenario, Users would bid with a capacity and associated load duration based on their intended operating regime and their access right would be defined to be consistent with this. This essentially means that the System Operator is making "composite" access products based on the additional load duration information provided by the Users.

4.2.1.13 The Working Group discussed whether load factor or load duration should be submitted by Users. The Working Group agreed that load factor did not provide sufficient information to the System Operator and therefore load duration information would be required. This point was demonstrated with a simple example of two generators, each with a load factor of 50%. Generator 1 operates at 50% output for 100% of the year and therefore does not cause any constraint costs.



4.2.1.14 Generator 2 operates at 100% output for 50% of the year and therefore causes a significant constraint cost.



4.2.1.15 The Working Group agreed that it may not be appropriate to allow tailored access products of this type to be traded or shared due to the associated complexity.

4.2.1.16 The System Operator would be obliged to provide the level of long-term access rights described by the load duration booked at a stable long-term asset based price (e.g.TNUoS) and the User would be required to face the short-term access price (by utilising short-term access products or sharing transmission capacity) for output above this load duration.

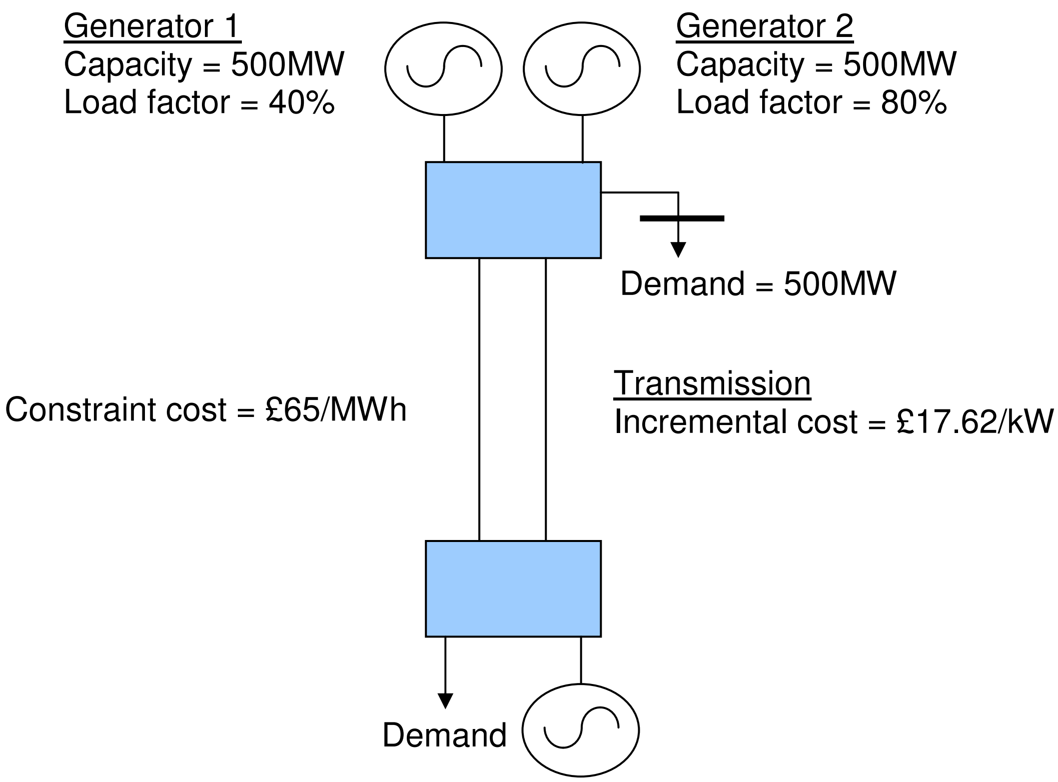
4.2.1.17 The Working Group discussed the practical difficulties associated with monitoring and charging as overrun any output above a long-term access right (when that right is defined as a load duration). The following options were discussed:

- Temporal approach
  Monitor generation output during the year and when the load duration purchased as a long-term right has been used, charge any additional output at the prevailing overrun price. This would tend to skew the Users exposure to overrun charges such that they were liable for the overrun charges that prevail at the end of a particular year.
- Average approach
  Monitor generation output during the year and when the load duration purchased as a long-term right has been used, charge any additional output at the annual average overrun price. This would address the issue identified above with a skew to the end of a particular year but a liability to pay an average charge may lead to inappropriate short-term incentives on the generator.
- User defined approach

For each half-hour, the User would specify in advance whether they would be using their long-term access right load duration profile or overrunning. Some Working Group members preferred this approach, with others concerned that the specification would have to be made sufficiently ahead of real time to prevent the generator reacting to the prevailing overrun price as this could invalidate the assumptions that were used to generate the Users access price.

4.2.1.18 The Working Group discussed the appropriate pricing of long-term access rights tailored by load duration restrictions. The Working Group agreed that, in principle, if the access restrictions accepted by generators lead to less investment being required on the transmission network, then a lower price for the long-term access rights is appropriate.

4.2.1.19 In order to investigate this issue further, the Working Group considered a simple idealised model which calculates transmission investment costs and constraint costs as a function of transmission capability. This model is described below.



4.2.1.20 The 500MW demand connected at the same substation as generator 1 and generator 2 has the following typical annual characteristic.

Demand level	Proportion of year
50%	53%
75%	33%
85%	11%
100%	3%

4.2.1.21 Generator 1 is assumed to be a wind generator with the following load duration.

Output level	Proportion of year
0%	0%

20%	50%
40%	20%
60%	15%
80%	10%
100%	5%

4.2.1.22 Generator 2 is assumed to be a conventional power station with five 100MW units. In order to estimate a load duration characteristic, a binominal distribution has been assumed. The Working Group noted that the use of a binomial distribution assumes that the running of each of the units is completely independent and that this is unlikely to be the case for a power station. The load duration determined based on the binomial distribution is shown below.

Output level	Proportion of year
0%	0%
20%	1%
40%	5%
60%	20%
80%	41%
100%	33%

4.2.1.23 In order to calculate a central view of the constraint cost for a particular transmission capability, the load duration characteristics for generator 1 and generator 2 are combined at each demand level in order to calculate a central view of the constraint volume in MWh. This constraint volume is multiplied by the assumed constraint cost of £65/MWh in this example in order to establish an annual constraint cost.

4.2.1.24 In order to calculate a transmission investment cost for a particular transmission capability, TNUoS prices (in £/kW) were assumed.

4.2.1.25 For the example shown in the diagram above, the minimum overall annual cost (central view constraint cost + investment cost) is given by a transmission capability of 650MW.

4.2.1.26 In order to understand the risk associated with the central view of constraint costs, the worst case (generator 1 and generator 2 output is positively correlated) and best case (generator 1 and generator 2 output is negatively correlated) were also calculated. For a transmission capability of 650MW, the central view of the annual constraint cost is £499k in a range £0 to £4.968m.

4.2.1.27 The Working Group noted the large cost range and therefore the difficulty in identifying the minimum cost transmission investment level, even when Users commit to a load duration characteristic. The Working Group noted that whilst this range may be acceptable when considering wind (where output is determined by weather conditions) and nuclear (with an expectation of baseload operation), it is much more challenging for mid-merit thermal generation.

4.2.1.28 The Working Group also noted the issues associated with setting prices on the basis of an ex ante forecast of generation running, particularly for generators that can control their output. The Working Group questioned whether this approach leads to an incentive for conventional generators to declare themselves available on windy days and therefore exacerbate constraint costs above those assumed when investment and pricing decisions are made. The Working Group discussed whether the use of composite products of this type therefore necessitated arrangements which replicate the sharing incentives associated with holding the raw products. The Working Group was unable to resolve this issue in the timescales available.

4.2.1.29 The Working Group considered the appropriate mechanism for pricing for this approach. The simple idealised model described above could be improved and extended to model the GB transmission network. This would allow generation prices to be calculated based on their impact on the minimum cost level of transmission investment. A majority of the Working Group believed that a significant amount of work would be required to develop this charging model before any conclusions could be reached as to whether it provided an appropriate approach to the pricing of long-term transmission access rights.

4.2.1.30 For the avoidance of doubt, the auction design envisaged under scenario 2 has been captured in the report as Working Group Alternative Proposal 1 (WGAP1) and not as part of CAP166 original, WGAA1, WGAA2 or WGAA3. Due to the issues raised above, a majority of the Working Group agreed that this alternative should not be progressed under CAP166.

4.2.2 Auction bidding process

4.2.2.1 It is proposed that the capacity and duration auction should be a dynamic auction, such that there would be several rounds of bidding which would enable bidders to have an opportunity to revise their bids based on the information revealed in the previous rounds of bidding.

4.2.2.2 Within the Working Group there was debate about whether the auction should be designed such that there would be a restriction on a User's ability to revise their bids for their capacity requirement in subsequent rounds of the auction.

4.2.2.3 The two options considered were:

- 'descending only' auction; or
- 'ascending and descending' auction.

4.2.2.4 The various advantages and disadvantages of each are considered below, but during the debate there was no consensus of opinion as to which was the preferred approach. A vote was held to determine the appropriate way forward and a majority of the Working Group agreed that an ascending and descending auction was the appropriate way forward for WGAA3.

Descending Only Auction

4.2.2.5 A 'descending only' auction would restrict Users from submitting a bid for their required volume of capacity in a subsequent round of the auction which was greater than that provided in the previous round.

4.2.2.6 This type of auction was suggested based on the assumption that the price indicated by National Grid (for both the short-run and long-run products) after each round of the auction would be lower (or remain the same) in subsequent rounds if the volume of capacity requested within that zone was reduced (or remain unchanged).

4.2.2.7 This would therefore provide any User with the ability to effectively 'fix' its bids for capacity in any round of the auction (given the prices provided by National Grid in response to those bids) based on the knowledge that in subsequent rounds of the auction the prices could only reduce (or remain the same).

4.2.2.8 A natural consequence of this type of auction means that Users would need to submit bids for their maximum capacity requirement in any year of the auction in the first round of the auction as they could only reduce their bid for capacity requirement in any subsequent round.

4.2.2.9 However, there is a potential disadvantage with this type of auction design such that the auction could result in a sub-optimal allocation of capacity. Assume that all Users will bid in the first round of the auction for their maximum capacity requirement in a particular year of the auction (given the descending nature of the auction). If this happens, it is likely that demand will be above system capability at various points on the system and this will manifest itself by National Grid publishing high short-run and possibly long-run prices following that round of the auction.

4.2.2.10 It is possible that several Users would then decide to reduce their volume requirement during the next auction round in response to the price signals such that demand is then greatly reduced. This could then lead to lower short-run and potentially long-run prices which Users would then not be in a position to signal any response to. If this were the case, the auction is unlikely to result in the "efficient" allocation of rights to Users and could end up leading to an under-allocation of long-run rights on the system.

Ascending and Descending Auction

4.2.2.11 An alternative to the 'descending only' model approach is to allow Users to be able to either increase or decrease their volume requirement during subsequent rounds of the auction.

4.2.2.12 This would overcome the disadvantage outlined above for a 'descending only' auction such that Users would be able to fully respond to the pricing signals after each round of the auction. This means that the auction should result in a more "efficient" allocation of rights to Users.

4.2.2.13 However, it should be noted that this would mean that prices would no longer only reduce or remain unchanged between auction rounds. Users may therefore need to be more active in each round of the auction.

4.2.2.14 It was suggested that in order to ensure that Users can take a view on the maximum price they could be exposed to for access rights through the auction, if an 'ascending and descending' type of auction was proposed, then there should be a similar restriction to that proposed for the 'descending only' auction of requiring Users to submit their maximum capacity requirement in any year of the auction in the first round of the auction.

4.2.2.15 The main disadvantage of allowing Users to change their bid volumes either up or down in subsequent auction rounds is that the auction would be likely to stay open longer and could effectively 'time-out' on the last scheduled day.

4.2.2.16 In order to reduce the likelihood of this, stability criteria will be developed along similar lines to those which were suggested for the price-based auction, i.e. such as based on changes to the allocation of transmission access rights between two or three successive rounds falling within a pre-defined tolerance (in MW) or based on the price of those allocated access rights in two or three successive rounds being within a pre-defined tolerance.

4.2.3 Inclusion of buy-back as a parameter of the auction

4.2.3.1 As part of the debate around auction design, it was noted that in any auction which features ex-ante pricing of the short-run product, where there is effectively an 'over-allocation' against system capability, there was the possibility that Users could respond by effectively factoring that short-run price into any bid price they may submit in the Balancing Mechanism.

4.2.3.2 One way of mitigating such behaviour occurring would be to design the auction such that Users would be required to also submit a buy-back price as part of any bid for capacity. This price would then effectively cap any bid price that Users could then submit and hence lessen the possibility of this type of behaviour occurring.

4.2.3.3 The inclusion of such a buy-back price could then be used by National Grid in the calculation of the appropriate price which would be offered for the short-run product.

4.2.3.4 There was significant debate within the Working Group as to whether the inclusion of a buy-back price as part of the auction was the appropriate way to proceed. One of the main concerns around the inclusion of any cap on prices that Users could submit was that it could lead to a distortion of the prices within the Balancing Mechanism.

4.2.3.5 Additionally, some Working Group members suggested that it would be very difficult for certain Users to be able to provide a buy-back price several years forward and therefore concluded that this should not be a requirement of the auction. Although to mitigate this impact the Working Group noted that a buy-back price perhaps linked to a market price or fuel price might be worthy of further investigation, but that in the timescales available for assessment this option was not pursued any further.

4.2.3.6 However, at a principle level, if a User is prepared to provide such a buy-back price at the time of bidding this is useful information to the System Operator which should be of value and therefore rewarded via the pricing signals provided.

4.2.3.7 One way of addressing this could be to design the auction such that the submission of a buy-back price is optional, but that the price offered to the User would be affected by whether a buy-back price is offered or not.

4.2.3.8 If a User is willing to provide a buy-back price at the time of bidding for access rights, then that User would be offered an ex-ante price for its portion of short-run rights. Conversely, if a User is unwilling or unable to provide a buy-back price, then the User concerned might only be offered a higher fixed ex-ante price for the short-run product than a Party who did offer a buy-back.

4.2.3.9 In order to determine buy-back price, it was noted by the Working Group that a tender for balancing services contracts across all existing and potential Users in a zone could be approached prior to the commencement of an auction. If Users were willing to offer to reduce a proportion of their output for a fixed price or potentially agree to the installation of an intertrip or other restriction on output, then the costs of these balancing services could form the basis of the short-run priced access released into the forthcoming auction rounds. This, the group felt would offer the most competitive arena in which the concept of a buy-back price could be explored as it would not limit competition amongst those parties in the auction concerned but all parties within a zone. It was also noted that for certain zones there may be either no or highly limited competition in which case such a tender for balancing services could not be expected to function correctly. In such cases it would be at the discretion of the GBSO to offer terms for connection to Users that does not include a buy-back price, but rather a transmission related agreement (TRA). It was further noted by the Working Group that any such offers incorporating a TRA could be referred to the Authority by a User if that User felt the assumptions made by the GBSO regarding a lack of proper competition were invalid.

4.2.3.10 For the avoidance of doubt, the integral use of buy-back bids in the auction process has been captured in the report as Working Group Alternative Proposal 1 (WGAP1) and not as part of CAP166 original, WGAA1, WGAA2 or WGAA3. Due to the issues raised above, a majority of the Working Group agreed that this alternative should not be progressed under CAP166.

4.2.4 Pro-ration

4.2.4.1 One of the main differences between any Price based auction type (such as that proposed as WGAA1 or WGAA2) and a Capacity and Duration model (such as WGAA3) concerns the availability of rights to be auctioned.

4.2.4.2 Under the proposed Price based auction proposals, National Grid would indicate to Users the availability of system capability over a number of years (reflecting any planned investment) and that capacity would be auctioned to the highest priced bids first until it was fully allocated.

4.2.4.3 In the event that demand for capacity exceeded capability and the Users' bids could not be differentiated on price (i.e. several Users all bid the same price), then it was proposed that the Users' bids would be subject to simple pro-ration in order to ensure that the allocation of capacity was not above the system capability. Any requests for capacity above system capability would not be allocated.

4.2.4.4 Under the proposed Capacity and Duration model, Users are able to bid for any amount of capacity that they require in any year of the auction and National Grid will make that capacity available to the User. This means that in the period before the TOs are able to provide extra capacity on the system by incremental investment, there is likely to be an 'over-allocation' of rights when compared to system capability.

4.2.4.5 When such an 'over-allocation' occurs, under WGAA3, it was suggested that Users would be allocated a certain proportion of their rights based on the long-run price and the remainder of their capacity based at the short-run price.

4.2.4.6 Within the Working Group there was significant debate about how the actual physical capability could be allocated 'fairly' between competing Users especially given the interacting nature of the transmission system, as the prices paid for the different rights could be quite diverse.

4.2.4.7 In order to more fully consider any issues which pro-ration may cause, as an approximation to considering each individual node's influence on the capability of the system, the system was considered in terms of boundary capability. If there are interacting boundaries (such as nested boundaries) which all need pro-rating, the order in which the pro-ration is applied will affect the resulting allocation of capacity to the individual Users concerned.

4.2.4.8 The simplest methodology which was discussed was to consider all the boundaries on the system for which there was an over-allocation and then apply the lowest pro-ration ratio to all Users' bids that would be affected by that particular boundary and then repeat for each boundary.

4.2.4.9 Whilst this is relatively simple to apply, in the case where there are nested boundaries on the system, this can lead to an under-allocation of rights against the nested boundaries behind the one used in the pro-ration.

4.2.4.10 In order to overcome this shortcoming, it was proposed that a more 'equitable' manner for pro-rating on a system with nested boundaries would be to rank the boundaries such that the one with the highest 'over-allocation' would be considered first, then the next and so on until no further pro-ration was necessary.

4.2.4.11 Pro-ration is then applied at the highest ranked boundary first such that those Users affected by that boundary's pro-ration would have their allocation of rights carried out first such that their bids are pro-rated back to the boundary capability. Those allocations would then be fixed when the reassessment of pro-ration at any subsequent boundaries is made. An example of how this type of pro-ration would work is provided in Section 5 of the report when the details of WGAA3 are considered.

4.2.4.12 When examples of how this could work were discussed within the Working Group, it was felt that any form of pro-ration which did not consider the particular characteristics of the various Users could mean that rights may not be allocated in the most 'efficient' manner.

4.2.4.13 Further consideration was given to this issue and it was suggested that a particular User's load factor or load duration could be used in order to arrive at a more 'efficient' allocation. This is an area of work which may benefit from further assessment.

4.2.5 Effect of Pro-Ration on Current Transmission Access Baseline

4.2.5.1 When considering any methodology for pro-rating of Users' requests for capacity, it is clear that any such pro-ration is highly dependent on the particular system capability which has been assumed (as it ultimately affects the allocation of rights between the long-run priced capacity and short-run priced capacity).

4.2.5.2 During the discussions which took place when the Working Group considered the price based auction, the boundary which provoked the most discussion was the Cheviot boundary.

4.2.5.3 As was shown in paragraph 4.1.6.49, there is currently an 'over-allocation' at that boundary over its actual physical capability. The discussions which were previously held led to a suggestion that for the price based auction, the boundary capability should be set at the 2011/12 capability value of 3300MW.

4.2.5.4 Whilst there was some debate surrounding boundary capabilities to apply, especially at the Cheviot boundary, there was no conclusion of the appropriate level to use. It is therefore suggested that the derivation of the boundary capabilities to be used in the capacity and duration type model should be set out within the auction methodology statement. The impact of the Cheviot boundary capability (in particular the treatment of the derogation) agreed as part of the methodology on the long-term access rights held by Users is demonstrated in further detail below.

4.2.5.5 A spreadsheet was derived to explore in more detail the resulting pro-rated allocations of capacity using the methodology proposed in paragraph 4.2.4.11 above for all the boundaries from B6 northwards. This spreadsheet was also used to examine the effect of boundary capabilities on the results of such pro-ration.

4.2.5.6 Data from the 2008 SYS was used. For 2008/9 the following requirements for capacity have been assumed:

Type of Generation	Zones	Requirement (MW)
Pumped storage	Z1	300
Hydro&wind	Z1	562
CCGT	Z2	1524
Hydro&wind	Z2	44
Hydro	Z3	226
Pumped storage	Z3	440
Wind	Z3	0
Hydro	Z4	168
Wind	Z4	104
CHP	Z5	123
Coal	Z5	2304
Nuclear	Z6	2410
Wind	Z6	687
Other (incl cockenzie)	Z6	1352

4.2.5.7 Using this data and associated 2008/9 boundary capabilities, plus zonal demands results in the following pro-ration factors at the various boundaries:

Boundary	B1	B2	B3	B4	B5	B6
Capability plus demand	931	2614	266	3193	5430	8309
Total requested	862	2430	666	3368	5795	10244
Pro-ration	100%	100%	40%	95%	94%	81%

4.2.5.8 As can be seen, the most 'over-allocated' boundary is B3 (40%), hence this would be the first boundary to be pro-rated.

4.2.5.9 Applying this 40% pro-ration to all the zones affected by B3 (only Z3) results in the following allocations:

Type of Generation	Zones	Requirement (MW)	Allocation (MW)	% of Requirement
Hydro	Z3	226	90	40%
Pumped storage	Z3	440	176	40%
Wind	Z3	0	0	n/a

4.2.5.10 Fixing the allocations for the Z3 Users results in the new remaining boundary pro-ration factors:

Boundary	B1	B2	B4	B5	B6
Remaining capability (plus demand) to allocate	931	2614	2926	5164	8043
Total requested	862	2430	2702	5129	9578
Pro-ration	100%	100%	100%	100%	84%

4.2.5.11 As can be seen, the most 'over-allocated' boundary now is B6 (84%), hence this would be the next boundary to be pro-rated. Once B6 has been pro-rated, no further pro-ration is necessary and therefore the pro-ration process is complete. This results in the following allocations:

Type of Generation	Zones	Requirement (MW)	Allocation (MW)	% of Requirement
Pumped storage	Z1	300	252	84%
Hydro&wind	Z1	562	472	84%
CCGT	Z2	1524	1280	84%
Hydro&wind	Z2	44	37	84%
Hydro	Z3	226	90	40%
Pumped storage	Z3	440	176	40%
Wind	Z3	0	0	n/a
Hydro	Z4	168	141	84%
Wind	Z4	104	87	84%
CHP	Z5	123	103	84%
Coal	Z5	2304	1935	84%
Nuclear	Z6	2410	2024	84%
Wind	Z6	687	577	84%
Other (incl cockenzie)	Z6	1352	1135	84%

4.2.5.12 This means that the remainder of the Users' requirements for capacity would be provided by priced based on the short-run price and would be charged for either on a MWh or a MW basis by the particular Users.

4.2.5.13 If a higher capability for boundary B6 (such as the 2011/12 value of 3300 MW) was used, then again B3 would be the most 'over-allocated' boundary and would therefore be pro-rated first, but the pro-ration at B6 would not be so high (95% rather than 84%). This would result in the following allocations at the long-run price:

Type of Generation	Zones	Requirement (MW)	Allocation (MW)	% of Requirement
Pumped storage	Z1	300	286	95%
Hydro&wind	Z1	562.26	536	95%
CCGT	Z2	1524	1454	95%
Hydro&wind	Z2	44	42	95%
Hydro	Z3	225.82	90	40%
Pumped storage	Z3	440	176	40%
Wind	Z3	0	0	n/a
Hydro	Z4	167.5	160	95%
Wind	Z4	104	99	95%
CHP	Z5	123	117	95%
Coal	Z5	2304	2198	95%
Nuclear	Z6	2410	2299	95%
Wind	Z6	687.4	656	95%
Other (incl cockenzie)	Z6	1352	1290	95%

4.2.5.14 Again the remainder of the Users' requirements for capacity would be priced at the short-run price (paid for either on a MWh or a MW basis by the particular Users).

4.2.5.15 However, it should be noted that any increase to the assumed boundary capability would result in a greater proportion of the Users' requirements being priced on a long-run price basis and therefore a lower amount at the short-run price than before. This means that the constraint costs which resulted from any such 'over-allocation' would be socialised rather than targeted at particular Users.

4.2.5.16 The analysis has been repeated using the corresponding data for 2014/15 (boundary data, demand and generation). Again this results in B3 being the most 'over-allocated' boundary (this time 45%) which would then be followed by B6 (65%). In this case the allocations at the long-run price would be:

Type of Generation	Zones	Requirement (MW)	Allocation (MW)	% of Requirement
Pumped storage	Z1	300	192	64%
Hydro&wind	Z1	2103	1349	64%
CCGT	Z2	1524	977	64%
Hydro&wind	Z2	157	100	64%
Hydro	Z3	226	102	45%
Pumped storage	Z3	440	198	45%
Wind	Z3	278	125	45%
Hydro	Z4	168	107	64%
Wind	Z4	408	262	64%
CHP	Z5	123	79	64%
Coal	Z5	2304	1478	64%
Nuclear	Z6	2410	1546	64%
Wind	Z6	3647	2339	64%
Other (incl cockenzie)	Z6	1352	867	64%

4.2.5.17 This shows that for this set of data, a lower proportion of Users' rights would be priced at the long-run price and therefore a significantly higher proportion of Users' rights would be priced at the short-run price.

4.2.6 Validation Tests

4.2.6.1 The Working Group considered that where final capacity allocation priced at the LRMC price was pro-rated based on the capacity a User bid in the auction, there could be an incentive to bid above the capacity a User actually required in order to receive a greater share of the pro-rated capacity. This could be a problem if the short-run price was on a usage (£/MWh) basis rather than a capacity (£/MW) basis since it would mean that the User could avoid being exposed to the short-run price.

4.2.6.2 Over booking is only a problem when Users are prorated, as once the capacity has been built the User will pay the full LRMC charge for the bid capacity. The purpose of a validation test is to persuade Users to only bid up to their actual capacity requirement in the auction. The Working Group noted that Users' bids would be limited to their LCN. This substantially reduced the opportunity for Users to overbook. The Working Group also noted that any system that involved the removal of User's rights but still obliged them to pay for them may be unlawful as it may amount to a deprivation of property rights. The sanctions developed around the validation test (described below) are therefore carefully constructed so as to either remove any right and the associated liability or allow the User to keep the right and the liability.

4.2.6.3 New Users would be able to prove their generating capacity by providing the standard information which is collected through comissioning. New Users capacity would need to be greater than or equal to their capacity bid in the auction. The existing CAP150 process would be utilised to reduce New Users pro-rated capacity should it emerge that a Power Station under construction was not able to fully utilise any auction procured pro-rated capacity.

4.2.6.4 The generation capacity of existing Users would be validated firstly by reviewing the output of their generation units during the year. If this led to suspicion that an over booking had been made an independent engineer would be requested to review the capability of the generating units to generate the bid capacity. If the independent engineer considered that an over booking had been made capacity would be reduced although the generator could refer the reduction to the Authority. Finally a validation run could be requested and the generator would be expected to demonstrate their ability to generate up to the bid capacity.

4.2.6.5 The group noted that it would be difficult for some units to demonstrate their maximum output on request due to their technology type. For example, wind generators would only be able to generate at their maximum capacity under certain wind speeds. This would need to be taken into account during the validation process.

4.2.6.6 If a User failed the validation test they would still be liable to pay for their bid capacity in years where they were not prorated. In years where their capacity had been prorated based on a inflated figure the pro-ration would be repeated using their actual validated capacity. Any capacity priced at LRMC released through this process would be reallocated to Users who had taken part in the original auction.

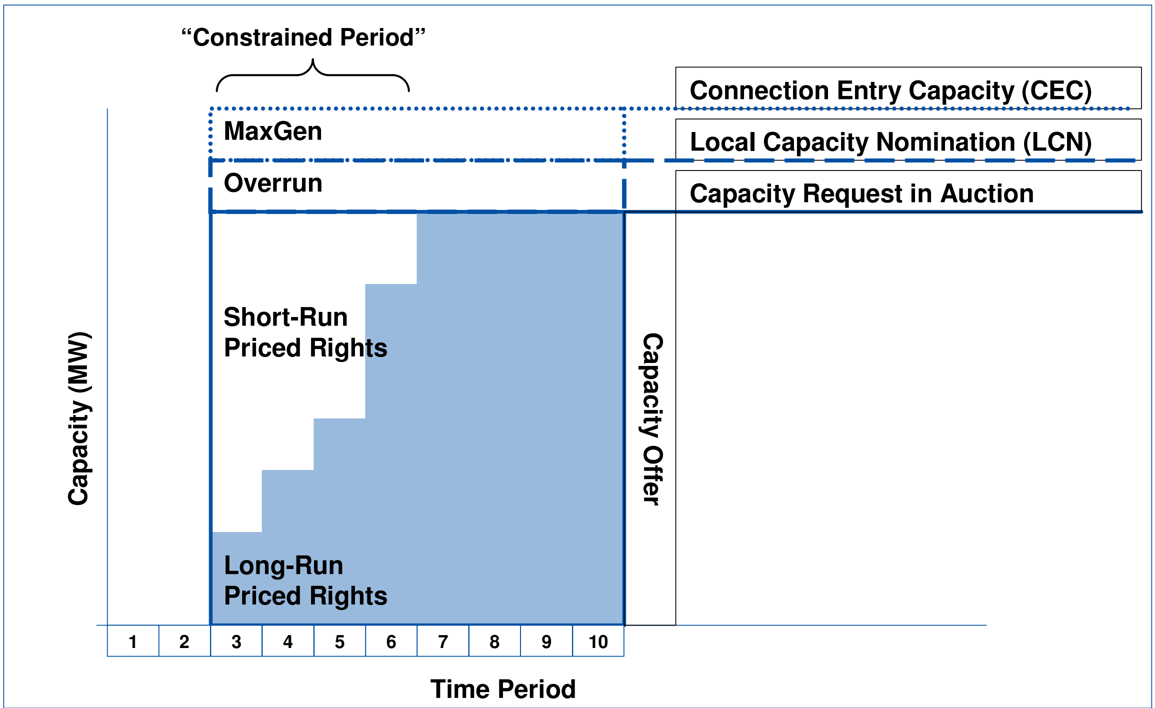
4.2.6.7 The Working Group noted that the concept of a Validation Test in effect shifted transmission access from being a right to generate up to a certain capacity to an obligation to be able to in the pro-rated period. Although in times of access scarcity the benefits of not allowing capacity that cannot be used to be hoarded were also recognised by some Working Group members, 4.2.6.8 Working Group members also noted that the concept of a validation run still had its pitfalls in that it would not be able to differentiate between a User who had chosen not to buy fuel and run an otherwise fully operational generating unit (who under the proposed rules would not have capacity withdrawn) or a User who had chosen not to repair a broken down generating unit (whose capacity would be withdrawn under the above validation test rules).

4.2.6.9 The practical impact of the CAP150 test on new Users was also briefly discussed by the Working Group. It was concluded that should a new User experience delays in the construction and or commissioning of its new power station then CAP150 would remove any right to use pro-rated capacity in the years following the original Completion Date up until its new Completion Date for the Power Station. However in years subsequent to the new Completion Date it would retain its access rights (and liabilities to pay for them) unless it moved beyond its “back-stop date” in its construction agreement in which case its agreement may be terminated, it would lose all access rights and also become liable for cost reflective final sums.

4.2.7 Short-Run Pricing Issues

4.2.7.1 The key to the capacity duration Working Group alternatives is the period (the "constrained period") where Users signal a requirement for transmission system access but where the infrastructure to deliver that cannot be delivered due to the practicalities of constructing transmission system assets. It is in this key period that existing infrastructure may be able to be used where for instance other generators that have rights to use it are not using it, or through managing the output of generators operationally to ensure that the transmission system remains within operational SQSS planning standards.

4.2.7.2 The key then to signalling to Users the costs of accessing the system prior to the date that a Transmission Owner is physically able to deliver the assets is the forecast of the short-run operational costs.



4.2.7.3 The Working Group discussed the options for the pricing of the short-run access rights seen in the "Constrained Period". Broadly speaking they fell into the following categories:

4.2.7.4 **Option 1a – Commoditised (£/MWh):** In this option the GBSO would derive a price reflective of the forecast operational costs associated with releasing access rights in excess of those capable of being provided by the physical assets. This price would be recalculated at the end of each auction round and is set at the short-run price that prevails in the last auction round before the auction closes. Users with access rights priced at this short-run price would then be locked into this short-run price for as long as they hold short-run price access rights (i.e. up until transmission system reinforcements have been constructed). Users would then have to pay this price for every MWh of output above their long-run priced access rights in settlement periods where they are contributing towards an export constraint.

4.2.7.5 **Option 1b – Commoditised (£/MWh):** The price in option 1b would be calculated exactly as per the rules outlined in option 1a except that there would be further "re-openers" that may see the short-run price re-calculated following the close of the auction in which the rights were allocated. Such "re-openers" would include:

- The termination of a Bilateral Agreement by a User who holds Short-Term priced access rights. (NB only the short-run price payable by Users who secured short-term priced access in the same auction as the terminating party would be affected);
- Changes in Power Prices (this could either be through defining a threshold or through indexing the short-run price to a pre-defined power-exchange index;
- Changes in System Operator costs – e.g. through an index to BSUoS charges
- Routine annual / 6-monthly re-forecasts of short-run prices to account for changes in observed costs which would account for all of the above "re-openers".

4.2.7.6 **Option 2 – Commoditised (£/MWh):** The price calculation in option 2 is similar to those outlined for option 1a and 1b above. However in this case a range of scenarios of expected generation output would be used to construct a forecast price for varying depths of constraint. That is to say Users would be locked into a price curve for the short-run costs and depending on the depth of the constraint; Users would pay a varying price. This curve would be generated after every round of the auction and would be fixed for all Users who secure short-run priced access in that auction at the curve generated for the final auction round. There may be scope to incorporate "re-openers" in line with those proposed for option 1b above; however given the more dynamic nature of the price curve in this option, it may be less necessary to incorporate such re-openers in this option.

4.2.7.7 **Option 3 – Capacity Based (£/MW):** The price calculation in option 3 is significantly different to that outlined above for options 1a, 1b and 2 above being on a capacity basis rather than a commoditised basis. The price calculated in this option would remain as two prices for short and long-run priced capacity. National Grid would then assess the volumes of capacity that could be released and the associated investment (LRMC) and operational (SRMC) costs of doing so with the objective being to maximise capacity release for the lowest overall cost. This cost would then be converted to a dual price (an LRMC element and an SRMC element) for capacity at a node and these would be the prices offered to Users through each round of the auction. This process would be repeated in each round until such time as the auction closes.

4.2.7.8 Each of the above options has its own benefits and disadvantages. Four key high level issues emerge:

1. The ability of the System Operator to accurately forecast the constraint costs into the future;

2. The real time incentives that the options give to holders of short-run rights when an export constraint is active;

3. The effectiveness of fixing an ex-ante price when real-time prices are variable; and,

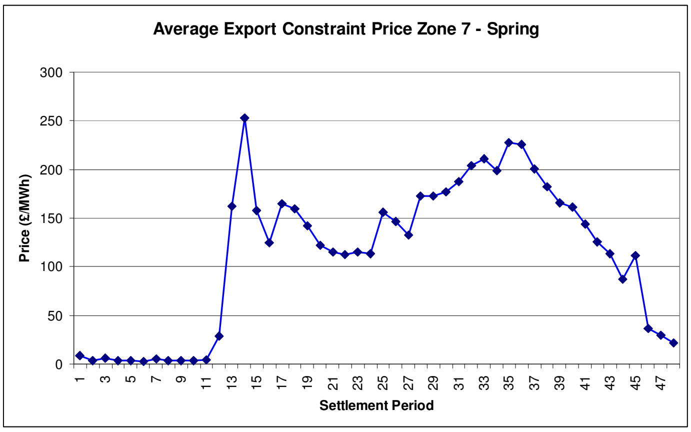
4. The potential effects that pricing may have on the wider market for energy in the Balancing Mechanism

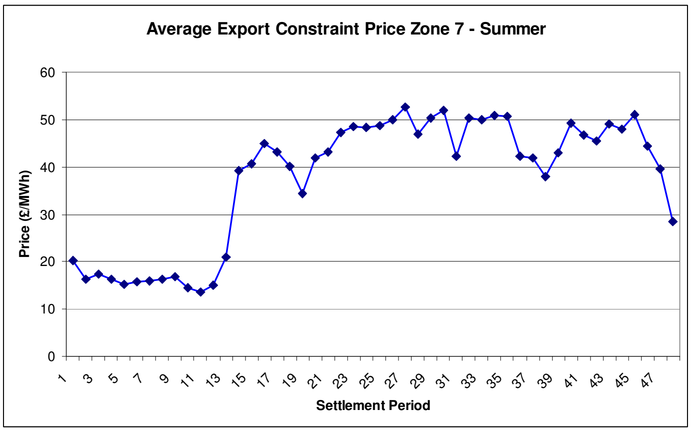
Forecasting

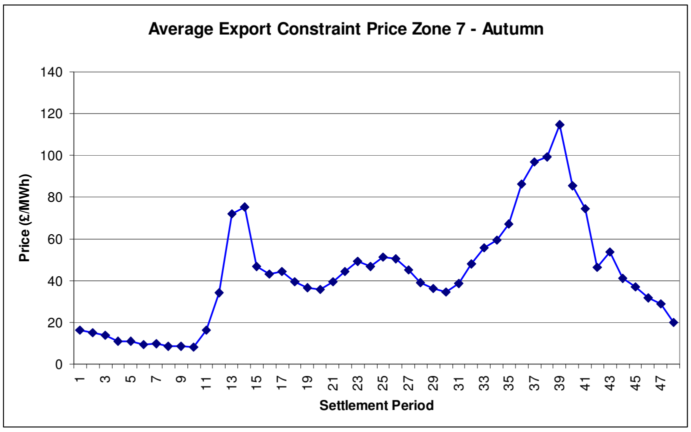
4.2.7.9 Of the above options option 1a and 1b are reliant on historic data analysis with options 2 and 3 reliant on a much more complex forward looking model.

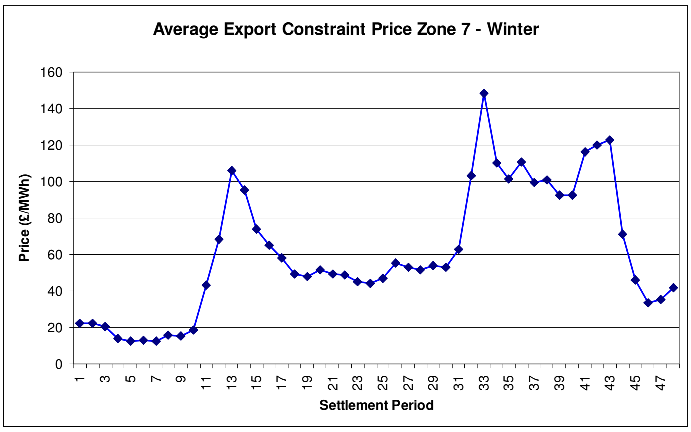
4.2.7.10 Historic analysis clearly presents much less of an issue than forward looking analysis and National Grid was able to present to the Working Group analysis of the historic costs of constraints across Great Britain, split according to the zones developed by Working Group 1 for the purposes of assessing the short-term access modifications CAP161-164. This produced both a flat average price of export constraints by zone and also a daily profiled price of export constraints per zone, in each case when the constraint was active. Sample results of this analysis are presented below

Sample Daily Profiled Prices: Zone 7: Cheviot Boundary









Total Figures (1 April 2005 – 31 March 2008)

SEASON	Total Volume (MWh)	Total Cost
Spring	149,150	£21,395,820
Summer	390,805	£16,520,774
Autumn	288,278	£14,509,280
Winter	301,094	£21,763,138
Total	**1,129,326**	**£74,189,012**

3 Year Average Price	£65.69/MWh

Sample Flat Charge: Great Britain:

Zone	Total Volume (MWh)	Total Cost (£)	Volume Weighted Average Price (£/MWh)
1	1,606,779	£95,982,158	£59.74
2	1,606,920	£95,985,795	£59.73
3	1,807,549	£103,386,633	£57.20
4	1,288,003	£81,671,636	£63.41
5	1,495,720	£89,962,616	£60.15
6	1,501,847	£90,146,617	£60.02
7	1,129,326	£74,189,012	£65.69
8	1,354,091	£82,844,594	£61.18
9	197,465	£7,586,168	£38.42
10	197,687	£7,553,142	£38.21
11	206,719	£7,540,058	£36.47
12	185,285	£6,880,401	£37.13
13	305,259	£12,238,419	£40.09
14	272,637	£9,886,925	£36.26
15	185,938	£7,630,668	£41.04
16	162,742	£4,820,093	£29.62
17	234,633	£8,309,068	£35.41
18	159,684	£4,522,586	£28.32
19	11,864	£536,539	£45.22
20	114,493	£2,626,964	£22.94
21	1,547	£159,021	£102.79
22	158,894*	£8,303,705*	£52.26*
23	3,577	£102,812	£28.74
24	23,783	£3,245,336	£136.46

4.2.7.11 Such prices would form the basis of the charges under options 1a and 1b.

4.2.7.12 The proposed pricing methodologies for options 2 and 3 would be necessarily more complex and would require the development of a significantly more complex model. Such a model would require modelling of the entire GB Transmission System and the generation and demand scenarios around it. Ultimately the methodology and the model that would be required would need to be developed under charging governance, however the Working Group noted the high degree of complexity of such a model.

4.2.7.13 The Working Group also noted the general sensitivity of constraint costs to a number of external variables and the fact that although a central forecast figure can be achieved the standard deviation around this model is large and as such the volatility of such a forecast is similarly high (see the section **4.2**). This is true even for forecasts in year-ahead timescales and the accuracy and uncertainty of years further into the future could be expected to be significantly worse.

Real-Time Incentives on Users

4.2.7.14 All of the volume-duration models have the concept of a fixed ex-ante price, however whether this should be levied on a £/MWh or £/MW basis remains an issue to be resolved through a separate charging consultation. The Working Group did however note that the £/MWh price did have the incentive of discouraging generation when the constraint was active, whereas the £/MW price, being effectively a sunk cost across the year did not have this property. It was noted by the Working Group that the £/MW charge could be structured such that it is levied only when the constraint is active and perhaps only when Users are generating using their short-run priced access in an attempt to retain some form of pricing signal on the User. Ultimately however it was noted that the development of all pricing options will be a matter for an accompanying charging consultation.

Effectiveness of an ex-ante price

4.2.7.15 It was noted that setting an ex-ante price for short-run access based on the forecast cost of constraints in a given year may not be effective given that this price could immediately be factored into real-time prices by Users. Thus if a User expected to be charged £80/MWh if a constraint in its zone were to be active and generates using short-term access rights, then the User may price any Bids in the Balancing mechanism at -£80/MWh to ensure that if it is constrained then it will recover its costs.

4.2.7.16 Clearly there is still the risk to the User that it may not be constrained back as other more economic options are available, however it is clear to see that the potential for BM prices to be significantly impacted remains.

4.2.7.17 One potential avenue that could be explored to prevent this would be to require a compulsory fixed buy-back price to be tendered in advance of the final price of constraints becoming known and to factor this into the pricing assessment. However as discussed in section 4.2.3 this approach is not without its own issues.

Impact on the BM Energy Market

4.2.7.18 The above potential impact on BM prices could also have the potential to impact onto the BM energy market as Users price their Bids based upon an expectation that they may incur short-run charges when a constraint is active. The likelihood however is that much of the time a constraint will not be active but the BM price will remain driven by system costs rather than energy costs. Thus there is significant potential for the energy market to become significantly impacted by a perception of system costs rather than the fundamentals of the energy market itself.

Working Group Consensus

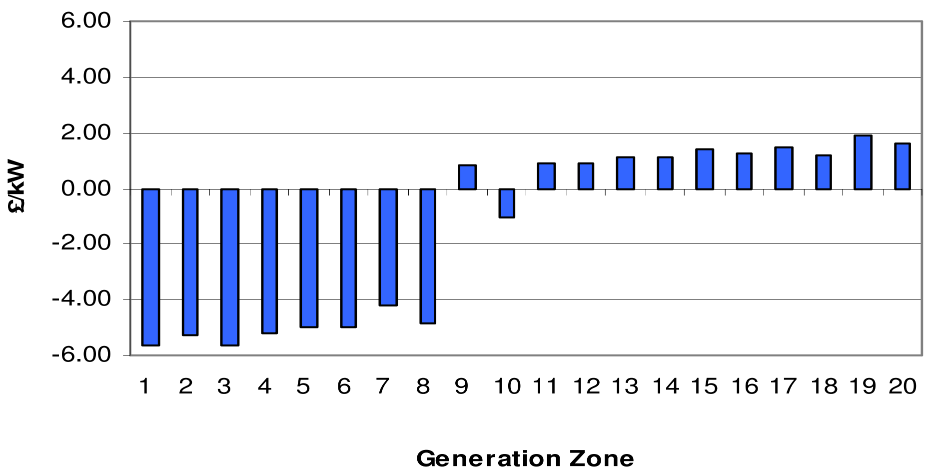
4.2.7.19 The Working Group reached the consensus position that the preferred pricing approach would be to adopt a £/MWh price that would be charged when a constraint was active. This approach, the Working Group felt, would provide the most appropriate signal to minimise generation that utilises short-run priced access and would also be most easily priced into the energy market decisions to be taken by Users when considering whether to generate using short-run priced rights. The Working Group agreed that the options should be developed in further detail under the charging governance arrangements.

4.2.8 Long-run Pricing Issues

4.2.8.1 The Working Group considered that the price for the auctioned capacity which was based on infrastructure would be priced based on the long run marginal cost (LRMC) calculated by the transport model. Under the current charging arrangements this is the locational element of TNUoS. The details of how this charge will be calculated will be consulted on under the charging governance. However the Working Group discussions did cover the following points.

4.2.8.2 The group noted that some boundaries on the current system were over allocated. Currently generation above system capability is included in the transport model and charged TNUoS. Under the new model capacity above system capability would be priced based on the short run costs. To avoid double counting this capacity would need to be removed from the transport model.

4.2.8.3 Analysis was performed to show the effect on TNUoS tariffs if generation capacity is pro rated behind an over allocated boundary. The analysis used the Scotland England boundary. The results showed a significant change in TNUoS tariffs. This difference between including over allocated capacity and not including over allocated capacity is described in the following chart. Tariffs reduced above the boundary where generation had been prorated.



4.2.8.4 The group also acknowledged that there would be some uncertainly in calculating a cost reflective price for the capacity into the future where National Grid were unsure of what changes would be made to the network. The condition five analysis was reviewed and it was considered that generation and demand information had a relatively more significant effect on the charges compared with network developments. Under the auction arrangements improved data should be collected regarding generation connections and closures.

4.2.8.5 The Working Group agreed that these issues would benefit from further development under the charging governance arrangements.

4.2.9 Impact of Capacity / Duration Auction on TNUoS Charging

4.2.9.1 As noted above in the discussions around the price based auction, it is important to note at this stage that there are some differences between the prices that emerge from an auction of this type compared with those from the present TNUoS methodology.

4.2.9.2 Under a Capacity / Duration auction ultimately the costs of the transmission network will be reflected in the Long-Run Marginal Cost element of the access charge. In the short term however the price charged to Users for access rights will also be influenced by the degree of demand for transmission access rights over the capability of the local transmission network to provide them.

4.2.9.3 These Short-Run Marginal Costs effectively offset BSUoS charges in constrained zones as they seek to charge ex-ante National Grid's forecast of operational costs on a given constrained zone (i.e. a zone that has an over-allocation of access rights in the short term). It is therefore envisaged that such short run marginal revenues would be offset against the other cost elements of BSUoS charges.

4.2.9.4 Finally the likelihood remains that two neighbouring generators who procure their transmission access rights in different auctions will end up paying different charges, although it is likely that in the long-run these will differ only marginally. The short-run costs might be very different as the earlier generator benefits from any "spare" capacity in the zone, which of course has been fully utilised by the time the second generator applies. As the long-run costs are fixed for the duration of the access booking there may be differences in treatment of the two generators as assumptions about future year's transmission investment are refined based upon demand for capacity.

4.2.10 Existing Transmission Related Agreements

4.2.10.1 The subject of the existing transmission related agreements within existing Bilateral Agreements between National Grid and Users was briefly discussed by the Working Group. Given the potential for the interaction between these TRAs and the auction through the calculation of short-run prices it was noted that this was an area that required further detailed consideration should WGAA3 ultimately be implemented.

4.3 Working Group Alternative Proposal 1 (WGAP1)

This Working Group Alternative Proposal was developed as part of the discussions around WGAA3 in the time extension granted to the Working Group. Ultimately the proposal was not adopted as a formal Working Group amendment as the Working Group felt that there were still significant areas where it needed to be developed further (specifically how a load duration and buyback price would be used in practice) and as such was not in a sufficiently fit state to be formally progressed. The development of the proposal as it stood at the final Working Group meeting held on 27 January 2009 is included here for completeness. It does not form part of CAP166 and is not therefore the subject of this consultation.

4.3.1 High level Design Concept

4.3.1.1 The Capacity and Duration Model proposed in WGAP1, is an annual auction based process designed to discover the nodal and/or zonal transmission charges. Users would bid an entry access capacity requirement based on a capacity in MW and duration in years at a node. In addition Users would also bid an annual load duration and an optional buyback price.

4.3.1.2 National Grid as GBSO would determine a single nodal ex-ante price of access at a node accounting for the long-run costs of investment in transmission infrastructure and the forecast short-run costs of constraints based on the entry access capacity requirement, the submitted load duration and the buyback price at that node. Such a price would be calculated for each year of the requested capacity booking and fixed at that level should the User be successful in the auction.

4.3.1.3 Following each auction round each User would receive a volume of access rights equal to that which it had bid for and the price at which it could procure these rights. It would also be tied contractually to it's buyback price (which in practice would cap the User's Bid submissions into the Balancing Mechanism) and its submitted load duration for the entire duration of its booking.

4.3.1.4 Users would have the opportunity to accept the charges at the node with the prices "fixed" or known for the duration of the bid, subject to adjustments that may occur as a results of other Users varying bids at their nodes in subsequent auction rounds. These adjustments should only result in costs that reduce for Users that have accepted the charges at a node.

4.3.1.5 In this model an entry node means a point of connection for a power station onto the transmission system. These points of connection are currently represented by the Transmission Entry Capacity (TEC) in a Bilateral Connection Agreement (BCA).

4.3.1.6 The high level design concept, for WGAP1, would include the ability for parties to overrun their firm capacity allocation up to the level of the physical connection capacity (however defined).

4.3.1.7 In the first auction to be run according to these principles all existing physical access rights would be withdrawn and then re-allocated through that first auction. In future rounds any access rights that had already been allocated via previous auctions would not be "re-auctioned" in effect meaning that future auctions would be for incremental capacity only.

4.3.1.8 This auction process is materially different to WGAA3 as it offers a composite of short-run and long-run products that balances both the ability of the transmission owners to construct transmission assets and also the economic balance between operational and asset related costs given a User's signalled intention to generate (through it's load duration submission).

4.3.2 The Auction Process

4.3.2.1 As part of WGAP1 the multi round auction process would be a based on Users bidding a capacity (MW) and duration (years) for each node where capacity is required. In addition Users could also submit their predicted load duration(s) for the period over which they require access rights and a buyback price.

4.3.2.2 Users who feel unable to directly specify their load duration for the given period would be defaulted to a 100% load duration – i.e. it would be assumed that they would be generating at full output for every settlement period in each year they have bid for.

4.3.2.3 Users could also choose to submit a buyback price alongside their volume, duration and load duration. Should a User choose not to submit a buyback price then it will lose out on any benefits associated with submitting that price.

4.3.2.4 Due to the additional parameters that are capable of being tendered into the auction and their likely interactions Users are free to flex them both up or down between each round in the auction.

4.3.2.5 As in WGAA3 there is no requirement on bidders to submit bids for consecutive years. The model enables Users to bid for capacity (MW) for an initial period and a subsequent period.

4.3.2.6 The GBSO will prepare an offer for each User for each bid at a node. The offer will set out the connection capacity and the liability for short run or long run charges. The offer will also include a bilateral connection agreement (BCA) and a construction agreement if transmission investment is required (either local or wider).

4.3.2.7 As part of WGAP1, after each auction round Users have the opportunity to vary any of their tendered parameters. Ultimately the auction would close (see below for closure rules) and the prevailing bids in that final round would be offered terms for connection / use of system in accordance with that Users tendered parameters at that time, together with the prevailing prices for such access.

4.3.2.8 The WGAP1 auction could close when there are no "significant changes" to the volume or duration of bids received across three consecutive auction rounds. "Significant changes" could mean, for example:

- Aggregate Users bids do not differ in each round from a fixed percentage (perhaps 5%) of volume; or
- Aggregate Users bids do not reduce by a fixed de minimis volume change (perhaps 10MW reduction); or
- bids do not differ in duration by more than say 2 years; or,

- The auction "times out" after a predefined number of rounds.

4.3.2.9 "Significant changes" could be established by reference to the material impact on the transmission system in relation to transmission investment and could vary around the network based on a transparent methodology for establishing them. The closure mechanism will be set ex ante so that Users can understand how the auction will close.

4.3.3 The Optimisation Process – deriving charges

4.3.3.1 As part of WGAP1 the GBSO would evaluate all bids received and operate an optimisation model based on a cost reflective approach for the whole transmission system.

4.3.3.2 The modelling process would in all auctions utilise the volume, duration and load durations tendered by Users to optimally calculate the most appropriate level of transmission investment for the requested capacity. This level will be determined by optimising the balance of access provided through infrastructure and the amount that can be provided through use of the existing network potentially with the risk of incurring constraints operationally.

4.3.3.3 The optimisation model will assess that correct balance and seek the lowest overall combination of infrastructure cost and operational cost. This will in turn result in the User receiving the lowest possible annual charge once all transmission investment has been constructed. In earlier years where less new transmission infrastructure is possible, it would be expected that the price offered for access would be higher due to the less optimal balance between operational and possible infrastructure costs.

4.3.3.4 The modelling process would use as the "background conditions" those Users that have "firm" booked transmission access rights allocated through previous auction processes (if any).

4.3.4 Pricing

4.3.4.1 A single fixed price of access would be determined in this alternative reflecting the costs of the infrastructure that is responsible for conveying the output of a Power Station together with the levels of incurred operational costs for doing so when there is insufficient transmission infrastructure available to do so. After a lead time sufficient to construct any new infrastructure the price would be expected to move to the optimal combination of transmission infrastructure and expected operational expenditure.

4.3.4.2 The exact manner in which the price would be calculated will be subject to a future use of system charging methodology pre-consultation (GB-ECM-016). However it is likely to require the development of a complex modelling solution that will nodally model each Power Station on the system, and probabilistically model the output of generators within their load duration curves and demand. It would also model the longer term reinforcements required to optimise the operational costs of managing constraints when viewed against the costs of additional transmission system reinforcement.

4.3.4.3 The price calculated would be charged on a £/MW basis in a similar manner to which existing TNUoS charges are levied.

4.3.5 Over- / Under-Recovery

4.3.5.1 Given the forecast nature of the variables used to generate the prices given to Users for access rights in this model it is likely that there will some levels of over and under-recovery inherent within the model.

4.3.5.2 The price calculated for access under this alternative can be thought of as replacing the locational element of generation TNUoS charges and also certain elements of BSUoS charges. Therefore it would be anticipated that any under or over-recovery of actual costs through these charges would be offset through adjustments to the residual TNUoS tariff or through adjustments to BSUoS charges. National Grid may also ultimately be incentivised to manage such under- or over recoveries.

4.3.6 Treatment of Overrun

4.3.6.1 Should the concept of overrun ultimately be introduced into the transmission access arrangements through any Authority approval of CAP162 then this model remains compatible with it. It is however not a simple matter to relate the two products due to the load duration curve characteristic of this model.

4.3.6.2 The load duration or load distribution curve restriction on a generators output requires a judgement to be made regarding whether a generator is in fact generating above its procured access rights. The load duration curve would define the number of hours a particular Power Station may generate above a certain percentage output. It is proposed that once a generator had “used up” all its available hours above a certain output, then any further generation at this percentage output or above would result in an overrun charge.

4.3.6.3 A variation to this would be if a generator had notified National Grid in advance that it wished to run on overrun for a particular period rather than utilise it permitted hours under the load duration curve. Should this be the case the generator would need to notify National Grid that it intends this charging arrangement to apply no later than gate closure for the settlement period in which it wishes to overrun. A User may notify a single settlement period or a block of settlement periods in which this arrangement is to occur provided that where a block is nominated gate closure for the first settlement period has not yet passed. Once a settlement period has been nominated as an “overrun” settlement period that notification is final and may not be reversed.

4.3.7 “Shareability”

4.3.7.1 Due to the unique nature of the combined product (it is likely to be unique due to assumptions regarding the tendered buyback price and load duration) so it becomes much more problematic to envisage widespread trading of the access product. To facilitate trading either National Grid would have to generate a complex exchange rate between two Power Stations to account for the tendered parameters of the “selling” Power Station and those of the “buying” Power Station which may not be particularly high if their characteristics are different (if indeed calculating such an exchange rate were to be feasible). Or the “buying” Power Station would need to agree to operate within the buy-back and load duration parameters tendered by the “selling” Power Station. These may not be particularly attractive to “buying” parties again restricting the likelihood of trading.

4.3.8 Design Variation Connections

4.3.8.1 The arrangements under a capacity and duration auction process are capable of recognising the implications of Users with design variation connections for revenue recovery. This can be achieved by ensuring that the tariffs that are offered to such Users reflect the lower investment costs at the node for such Users. Furthermore, if appropriate the applicable tariffs could also reflect arrangements where the User is subject to transmission capacity reductions in circumstances where circuits nominated in the connection agreement are unavailable.

4.3.9 Securities

4.3.9.1 It is proposed, as part of WGAP1 that under the volume and duration model pre commissioning liabilities would be managed through the construction agreement as now. Therefore if Users do not complete their works (i.e. build a power station) then they cannot connect to the transmission system and are liable for any "stranded" costs. This reflects the fact that stranded costs only occur if the User cannot complete its works and a connection agreement is terminated.

4.3.9.2 The nature of final sums arrangements with regard to security for transmission investment works is as being similar to the existing final sums methodology. These final sums should be cost reflective and identified as part of the auction process. Once a User has committed to pay the associated tariff then the final sums should be fixed in the construction agreement until such time as the User connects. This would enable the GBSO/TO to ensure that appropriate security is in pace. If the actual costs that are secured change then it is for the GBSO/TO to determine whether there is over security and advise the User of the lower liabilities. The User can chose to enter into a new agreement that reflects these final sums. However, the GBSO/TO cannot increase the liabilities if costs escalate and this additional risk would be borne by all Users and be subject to appropriate incentive arrangements with the GBSO/TO.

4.3.9.3 The use of a construction agreement and cost reflective final sums would enable negative tariff nodes or zones to be treated on the same basis as all other nodes (avoiding any discrimination). This would also ensure that appropriate security arrangements would be in place for any transmission works (local or wider) in negative tariff zones.

4.3.9.4 A construction agreement would also enable the issues associated with project delays and force majeure to be managed under the current arrangements.

4.3.9.5 It should be noted that where Users can use the system without a requirement for any transmission reinforcement that there would be no need for a construction agreement or any liabilities with regard to security for new investment and vice versa.

4.3.9.6 Using the current arrangements under a construction agreement would also enable the existing arrangements with regard to transmission reinforcement for existing connections (e.g. asset replacement) to be maintained (for example where time expired assets are being replaced).

4.3.10 Impact on Users connected to the transmission system

4.3.10.1 This section considers the potential impact of the WGAP1 capacity and duration auction model on existing and potential Users connected to the transmission system. The auction process gives the Users the opportunity to fix (hedge) the long run and short run costs of using the transmission system. This provides effective risk management which should result in an efficient and economic solution (subject to resolution of the over and under recovery issues).

4.3.10.2 From the perspective of different types of User the WGAP1 capacity and duration model has the following implications

- Existing User: The proposed arrangements would replace the existing obligations under the CUSC with regard to charging liabilities and rights to use the transmission system. Existing Users (be it that they are a current (commissioned) generator or a generator with a signed Bilateral Connection Agreement but not yet commissioned) would be required to bid in the first round alongside Users that wish to use the system in the future.

- Incremental Capacity: For existing Users that are seeking incremental capacity at a node where there is no requirement for additional wider transmission investment the charges would be based on the long run costs associated with the node.

- “Return to Service”: Under the capacity and duration model existing Users can book a limited duration of transmission access then take an outage period and subsequently return to service. However, the bid to return to service would be treated on the same basis as a new entrant since the existing capacity may have been allocated to another User. Therefore there may be an investment required in transmission reinforcement which may delay a firm allocation. During this investment period, the existing User could be exposed to the short run costs if it wishes to use the system.

- New Capacity: New Users would be able to bid for new firm transmission capacity in the auction process. Any offer would take into account the investment period required. If the local and wider works can be aligned then the User can use the system with firm long term transmission connection rights from the date that the works are completed.

- “Connect and Manage”: In certain circumstances, the GBSO/TO may be able to complete local works ahead of wider reinforcement works. In this case, the User can opt to complete on the basis of local works, subject to the short run costs. These short run costs would be applicable until such time as the wider reinforcement works are completed. This approach is analogous to the “Connect and Manage” arrangements currently under consideration in CAP164.

4.3.11 Impact on GBSO/TO

4.3.11.1 From the perspective of the GBSO and TOs, the User acceptances form the basis for revenue recovery with firm capacity charges recovering the long run marginal cost of investment in the transmission system and the constraint charges recovering the ex ante estimated short run constraint costs.

4.3.11.2 An over and under recovery mechanism is required to ensure revenue adequacy; which is the recovery of actual costs where they vary from the fixed LRMC and SRMC charges. There are a number of different options for the design of such a mechanism:

- LRMC under/over recovery could be addressed through adjustments to non locational residual;
- SRMC under/over recovery could be addressed through non locational BSUoS or
- SRMC shortfall recovery through zonal locational BSUoS or
- User specific relief from £/MWh SRMC cost in the event that the constraint costs are less than forecast

4.3.11.3 The WGAP1 capacity and duration model will have clear implications for the SO and TOs in relation to their licensed activities and their transmission price control. For example, any arrangements that fix revenues from Users whether in the form of short run or long run charges will have an impact on the amount of revenue recovery. In addition, there may be a requirement to introduce new incentive arrangements on the GBSO and or TOs in relation to short run costs and long run transmission investment. The price control and Licence may, therefore, require revision to enable the new arrangements to be implemented.

5.0 WORKING GROUP ALTERNATIVE AMENDMENTS

5.1 As a result of their discussions, Working Group members agreed three Working Group Alternative Amendments.

5.2 For clarity, the design options chosen in the original proposal, WGAA1, WGAA2 and WGAA3 are compared in the table below.

Design considerations	**Original**	**WGAA1**	**WGAA2**	**WGAA3**
Network analysis	Zonal	Boundary constraint		Nodal or boundary constraint*
Interaction between boundary capability and connected generation	Ex ante analysis	Multiple boundaries		Nodal representation or boundary constraint*
Baseline and incremental capacity	Together			
Definition of baseline capacity	Current long-term access rights (TEC)			Physical capability or current long-term access rights (TEC)*
Incremental capacity - Constraints	Unconstrained after [4] years	Constraints modelled @ wider & local level		
Incremental capacity - Multiple years	Together	Separate		
Incremental capacity - Planned schemes	Include in baseline			
Pricing	Pay-as-bid	Cleared (or marginal) price		Administered
Static/Dynamic	Dynamic			
Reserve price	Based on LRMC	No reserve price	Reserve prices reflecting LMRC or in “Over-allocated zones” LRMC + SRMC	Administered

* To be determined in Auction Methodology Statement

5.3 Working Group Alternative Amendment 1 (WGAA1)

5.3.1 Summary of WGAA1

5.3.1.1 WGAA1 was proposed by National Grid, and is based on a boundary constraint, dynamic, cleared price, multi-year auction as described in section 4 above. The auction will allocate capacity for a 40 year period i.e. the 2010 auction (run in autumn 2010) would allocate capacity from April 2011 to March 2051. All 40 annual allocations would run simultaneously in the auction. The methodology used for each of the years that are covered by the auction is summarised below:

- Establish physical boundaries and associated limits based on SQSS security criteria
- Establish demand at system peak in each zone
- Establish the supply function for incremental transmission capacity for each boundary for each year
- Establish for each boundary which zones participate in the flows in a particular direction across them.
- Enhance the boundary capabilities associated with derogated boundaries, e.g. England-Scotland boundary (SYS boundary B6) increased to accommodate derogation associated with BETTA transition arrangements
- Publish market information covering boundaries zones and incremental capacity (supply function).
- Invite bids for capacity in each zone for each of the years on a volume and price basis – Generators would be limited to a maximum number of Bids per Power Station equal to 5 × (Number of BMUs at the Power Station).
- Generators would also be able to set a “de-minimis” auction acceptance volume parameter that would limit the auction model from accepting a Bid from a Power Station if it was pro-rated or capped at a level below the de-minimis value specified.
- There will be no reserve price set across any of the auction boundaries.
- Run the boundary constraint auction to maximise notional value indicated by bids whilst ensuring that the flows across each boundary is not exceeded.
- Set the cleared prices based on accepted bids behind constrained boundaries
- Publish results to the market and allow for revision of bid price and volume with a reduction in volume being only reversible if another party subsequently reduces volume behind the same boundary
- A number of rounds would then ensue with the ability for auction participants to revise bid prices and volumes in each round. This process would continue until no further material movement takes place between three successive rounds of the auction. A contingency for a forced close by only allowing upward price and volume movements will be in place after [15] flexible auction rounds have taken place.
- The rounds would occur on each working day in September and October. Bids would be accepted from Users between 08:00 – 17:00 on each working day with the results of that round being published by 20:00 on the same day. The exception would be the first two rounds of the auction held in each year which would occur on the first and third working days of September. The extra day being to allow Users to fully appraise the results of the first round and further refine their bidding strategy.
- Capacity will be allocated based on auction result with fixed financial commitment based on boundary cleared price for each year.

5.3.2 Further Detail – WGAA1

5.3.2.1 For WGAA1, separate auctions will be held (simultaneously) for each (whole) financial year with incremental transmission capacity initially triggered in individual years when the additional bid revenue that could be accepted in that year is greater than 50% of the annuitised supply function for incremental transmission capacity. The results from each year would then be summarised between rounds. Incremental capacity would be released if:

- It is triggered in at least [8] individual years (since this represents 50% of supply function; or
- It is triggered in less than [8] years but the net present value of the additional bid revenue as a result of the reinforcement across all years is greater than 50% of the supply function.

5.3.2.2 The incremental capacity that passes this test would be re-entered into the auctions for individual years and the separate auctions would then be repeated and the results published prior to the next auction round.

5.3.2.3 This approach to incremental transmission capacity release would achieve an appropriate balance between the accuracy of the test for incremental capacity release, and complexity and transparency for Users. This approach would also avoid any issues associated with inefficient results being caused by precedence being given to Users that choose to bid for capacity over a longer period.

5.3.2.4 In order to avoid an inefficient over-allocation of long-term transmission access rights, constraints on the supply function for incremental transmission capacity will be modelled. These constraints will be calculated by the Transmission Licensees based on information that is provided by Users prior to the auction taking place. It is anticipated that this information will be collated as part of the local connection process.

5.3.2.5 Baseline and incremental capacity will be handled together in order to avoid uncertainty issues for the User (i.e. the User cannot establish a sensible bidding strategy for baseline capacity unless there is some certainty regarding the auction for incremental capacity).

5.3.2.6 The boundaries to be used are yet to be determined, however, a set of illustrative boundaries based on initial analysis can be found in annex 3.

5.3.2.7 The boundary transmission capacity that is allocated will be based on the deterministic rules contained in the prevailing (GB) Security and Quality of Supply Standard. For the main system boundaries where there is at least 1500 MW of demand additional capacity will be allocated as detailed in the current SQSS.

5.3.2.8 Pricing will be based on the relevant boundary cleared prices to ensure all Users participating in the same auction pay the same price for the same service in the same zone.

5.3.2.9 The WGAA1 auction will be dynamic with no limits on bidders ability to change their submitted price (i.e. there will be no reserve price), volume (MW) or duration details between rounds. Bidders will be limited to a maximum number of Bids per Power Station in each round. This upper limit will be set at 5 × (Number of BMUs at the Power Station).

5.3.2.10 This will allow Users who are not successful in winning a volume of transmission access rights above their Stable Export Limit or an acceptable duration (number of years) of access rights to effectively remove themselves from the auction by reducing their bid price. When reducing volume a following increase is only allowed if others reduce volume at behind the same boundary in the same auction round. There will also be an automatic "de-minimis" parameter within the auction which if used will allow an auction participant to signal that if a discrete bid is pro-rated or capped at a level less than the applicable de-minimis parameter then the auction must automatically disregard it.

5.3.2.11 In order to ensure that the auction closes, stability criteria will be developed based on changes to the allocation of transmission access rights between three successive rounds falling within a pre-defined tolerance (in MW) or the price of those allocated access rights in three successive rounds being within a pre-defined tolerance (in £/MW/year). It is likely that these stability criteria will allow for increases and reduction in price and volume although there will be some limitation of volume reduction if only one User reduces volume.

5.3.3 <u>Process for Allocating Wider Transmission Access Rights – WGAA1</u>

5.3.3.1 This section considers the potential impact of the auction process under WGAA1 on existing and potential Users of the transmission system. The auction process gives Users the opportunity to bid for long-term transmission access rights which provide the holder with a (perfect) hedge against the short-term value of transmission access (i.e. Users that operate within the access rights they purchase in the auction are not exposed to the short-term cost of transmission access).

5.3.3.2 The volume of long-term access rights released by the GBSO would be rationed to the physical capability of the transmission network, as defined by the GBSQSS. This means that Users can either operate using the short-term transmission access regime introduced by CAP161 ("SO Release" of short-term access rights), CAP162 (entry "Overrun") and CAP163 (entry access right "Sharing") or obtain a hedge against this by bidding for long-term access rights in the auction. If Users bid for long-term access rights only when the (cost-reflective) short-term price is higher, and the Transmission Licensees construct transmission assets in order to release long-term rights then this should result in an economic and efficient transmission network.

5.3.3.3 The possible outcomes for Users in terms the auction process associated with WGAA1, are illustrated below.

<u>Existing (pre and post-commissioning) User</u>

5.3.3.4 The proposed WGAA1 arrangements would replace the existing rights and obligations under the CUSC with regard to transmission access rights and charging liabilities. Existing Users would be required to bid for the long-term transmission access rights alongside Users that wish to use the system in the future.

5.3.3.5 The auction would be held once a year in the autumn for long-term transmission access rights starting from the following 1 April.

5.3.3.6 Prior to the commencement of the auction, National Grid would publish the access allocation model for each future year which would include the following information:

- Winter peak demand (MW) at each node;
- System boundaries and associated capabilities (in MW);
- Supply function for incremental transmission capacity associated with each boundary (including constraints on system boundary capability (MW) increases in each year)

5.3.3.7 Users would be able to use the access allocation model to investigate the access allocation that would result from any Users defined bidding scenarios.

5.3.3.8 Users would bid in each of the future years that they want long-term transmission access rights with the associated capacity (in MW) and price (in £/MW/year). Users would be able to bid for different capacities and with different prices in each year but would be limited to a maximum number of Bids per Power Station in each round equal to 5 × (number of BMUs at the Power Station).

5.3.3.9 Users would also be able to define an automatic “de-minimis” parameter within the auction which if used will allow an auction participant to signal that if a discrete bid is pro-rated or capped at a level less than their de-minimis parameter then the auction must automatically disregard it.

5.3.3.10 In the first round of the auction, bidding may be difficult since successful bidding involves accurately forecasting the clearing price, however, at the end of the first round, of the auction National Grid will publish the following information:

- Details of all bids submitted (price and volume);
- Long-term access right allocations in each year (MW at each node), including the associated cleared prices;
- Details of situations in which incremental boundary capability has been triggered.

5.3.3.11 Bidders then have an opportunity to make use of this information and revise their bids in a series of future rounds of the auction.

5.3.3.12 Further auction rounds would take place until the changes in transmission access allocation between three successive rounds fall below the pre-defined tolerance (in MW) or if the price of allocated access rights does not move outside of a pre-defined tolerance (in £/MW/year) in three successive rounds. The auction would then close.

5.3.3.13 Users that are successful in the auction would then receive the long-term transmission access rights (which provide a hedge against the short-term cost of transmission access) for the capacity (in MW) for which they were successful in the years in which they were successful.

5.3.3.14 Users would also be committed to paying the associated clearing price (£/MW/year) for these long-term access rights in the years in which they were successful.

5.3.3.15 If Users trigger incremental capacity and this is not provided by the TOs, the GBSO will be required to buy-back the capacity that cannot be provided.

5.3.3.16 Users that are unsuccessful in the auction could make use of the short-term access regime, or wait until the next auction for long-term access rights.

5.3.3.17 Under WGAA1 all generation Users (those utilising short-term access rights and long-term access rights) will be required to pay use of system charges which will be set to recover any difference (surplus or deficit) between the auction revenue and the proportion of the transmission licensees maximum allowed revenue to be recovered from generation Users (27%).

New (pre-commissioning) User

5.3.3.18 New Users would bid for long-term access rights in the auction alongside existing Users. The auction process would be as set out above for existing Users.

5.3.3.19 New Users will need a connection to the transmission system in order to make use of long-term access rights. New Users will be able to apply for local capacity with the offer remaining open until the auction of wider long-term access rights.

Impact on the System Operator and Transmission Owners

5.3.3.20 As part of WGAA1 National Grid (as the GBSO) will receive all User requests for local connections to the transmission system and will pass this information to the relevant TO. This information will be used to perform the network analysis required to calculate boundary capabilities and constraints on boundary capability increases. This work will be the responsibility of the TO with the GBSO taking a co-ordination role.

5.3.3.21 The TOs would need to provide details of the transmission system boundary capabilities (including any constraints on system boundary capability increases in each year) and supply functions for incremental transmission capacity.

5.3.3.22 The GBSO would need to take the information provided by the TOs and build the transmission access allocation model and publish for all Users. The GBSO would then need to administer the transmission access auction, including the publication of the required information after each round and monitoring allocation between rounds against the auction close-out criteria.

5.3.3.23 Following the WGAA1 auction, the GBSO will know the revenue to be recovered from generators based on the successful bids for long-term access rights in the auction. It is likely that there will be a difference between the total annual revenue recovered from the auction and the proportion of the maximum allowed revenue (27%) that is to be recovered from generation. This difference (surplus or deficit) will be passed back to all generation Users as part of the residual transmission use of system charge.

5.3.3.24 The TOs will know the boundary reinforcements that are required and the associated timescales and will be required to complete them to time. In the event that such reinforcements are not completed to time, the GBSO would need to buy-back the capacity. Arrangements for the funding of such buy-back payments will be agreed (outside of the CUSC); for instance it may not be appropriate to expose the TO to any such costs that result solely from consenting delays.

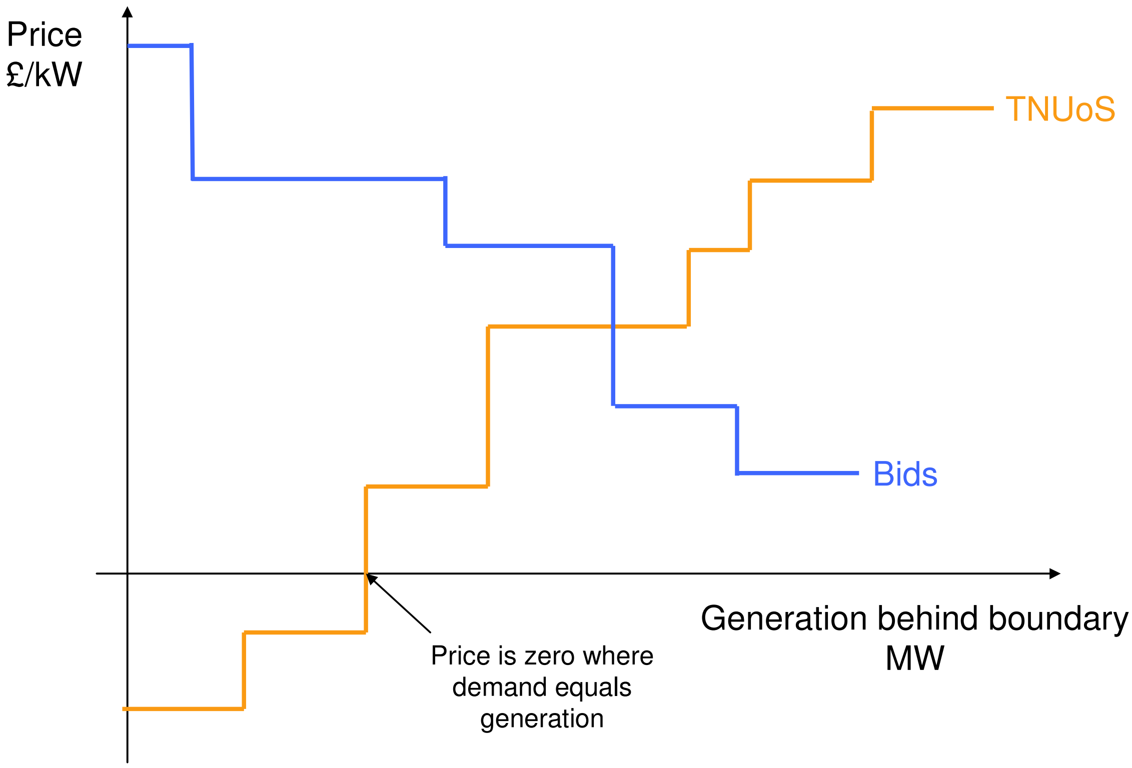
5.4 **Working Group Alternative Amendment 2 (WGAA2)**

5.4.1 Working Group Alternative 2 was developed from Working Group Consultation Request 2 proposed by National Grid and is predominantly based upon WGAA1. Its key difference is its treatment of Reserve Prices.

5.4.2 As noted in the Working Group discussions in Section 4 in WGAA2 the Reserve price will be utilised for two reasons:

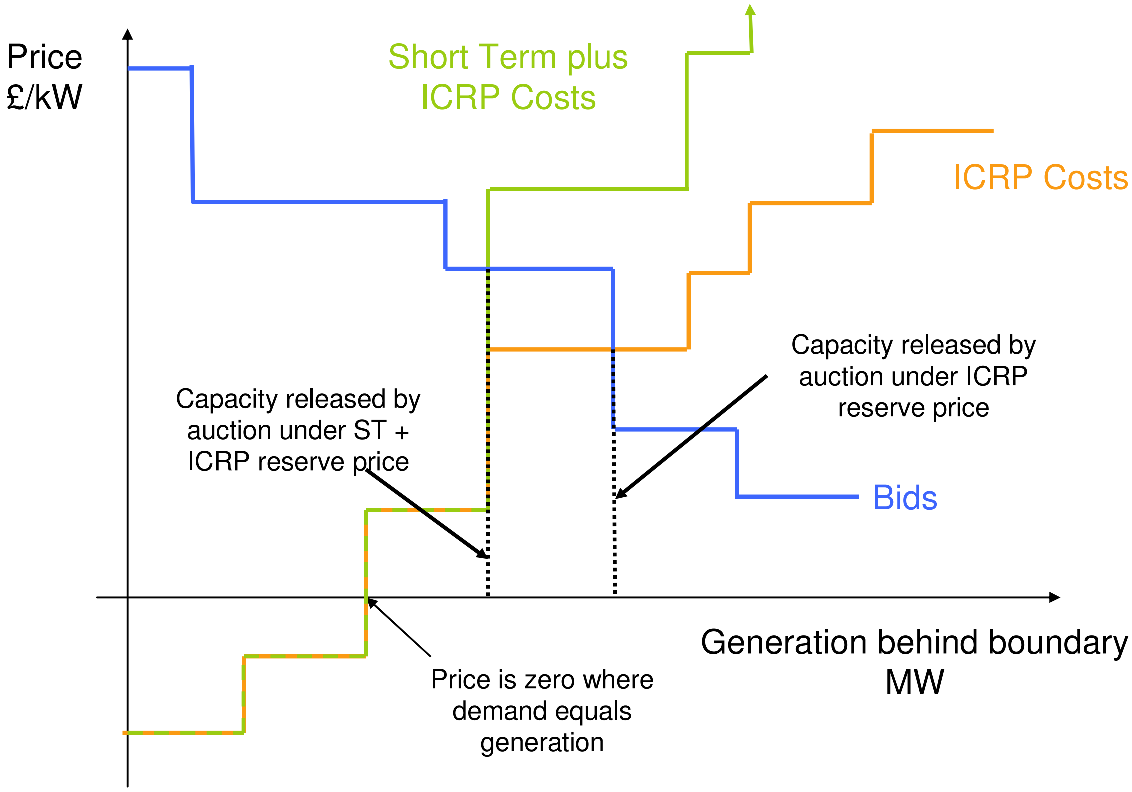
- The first is that it will be used to ensure that the Long-Run Marginal Costs of the GB Transmission System can be recovered from Users of Long-Term Access Products through the use of a Reserve Price that will at a minimum reflect the Long-Run Marginal Costs of the Transmission System.
- The second is to reflect the Short-Run Marginal Costs within the Reserve Price caused through any over-allocation of long-term transmission system access rights, for instance across the Cheviot (B6) boundary.

5.4.3 The application of the above methodology would result in Reserve Prices being set according to annual reserve price curves. These would see the Reserve Price Ramp up as more baseline capacity is allocated to reflect the incremental ramping of long-run marginal cost. The actual reserve price in each auction would then be set according to where the Bid Capacity supply curve crosses the Reserve Price Curve. This is shown in the diagram below.



5.4.4 In addition to this where the baseline capacity being allocated is in excess of that implied from a strict application of the GB SQSS planning standards (for instance over derogated boundaries such as the Cheviot boundary) the annual Reserve Price curves for years close to real time (i.e. before the lead times for incremental transmission system investment) will ramp according to both the long-run and short-run marginal costs. In longer lead times from real time, and as further incremental capacity can be physically constructed across an auction boundary, so the contribution from Short-Run Marginal Costs to an auction boundary reserve price curve will diminish before eventually only the Long-Run marginal Costs make up the reserve price curve.

5.4.5 The auction model used to assess auction bids will be constructed in the same manner as in WGAA1, i.e. it will be a boundary constraint, cleared price model, with the exception that it will additionally utilise these reserve price curves, whereas WGAA1 does not utilise reserve prices.



5.5 Working Group Alternative Amendment 3 (WGAA3)

5.5.1 *High level Design Concept*

5.5.1.1 The Capacity and Duration Model proposed in WGAA3, is an annual auction based process designed to discover the nodal transmission charges. Users would bid an entry access capacity requirement based on a capacity in MW and duration in years at a node. National Grid as GBSO would determine the nodal long term cost reflective charges at the node (LRMC) and the charge for the cost of constraints (SRMC) based on the entry access capacity requirement at that node. As a general rule, all capacity provided through physical assets will be priced at the long-run price, all other access rights provided without the physical assets in place to support them would be priced at the short-run price.

5.5.1.2 Following each auction round each User would receive an access capacity equal to that which it had bid for. A proportion of this (up to 100%) would be at the long-run price and any remainder priced at the short-run price. Users would have the opportunity to vary bids at their nodes in subsequent auction rounds.

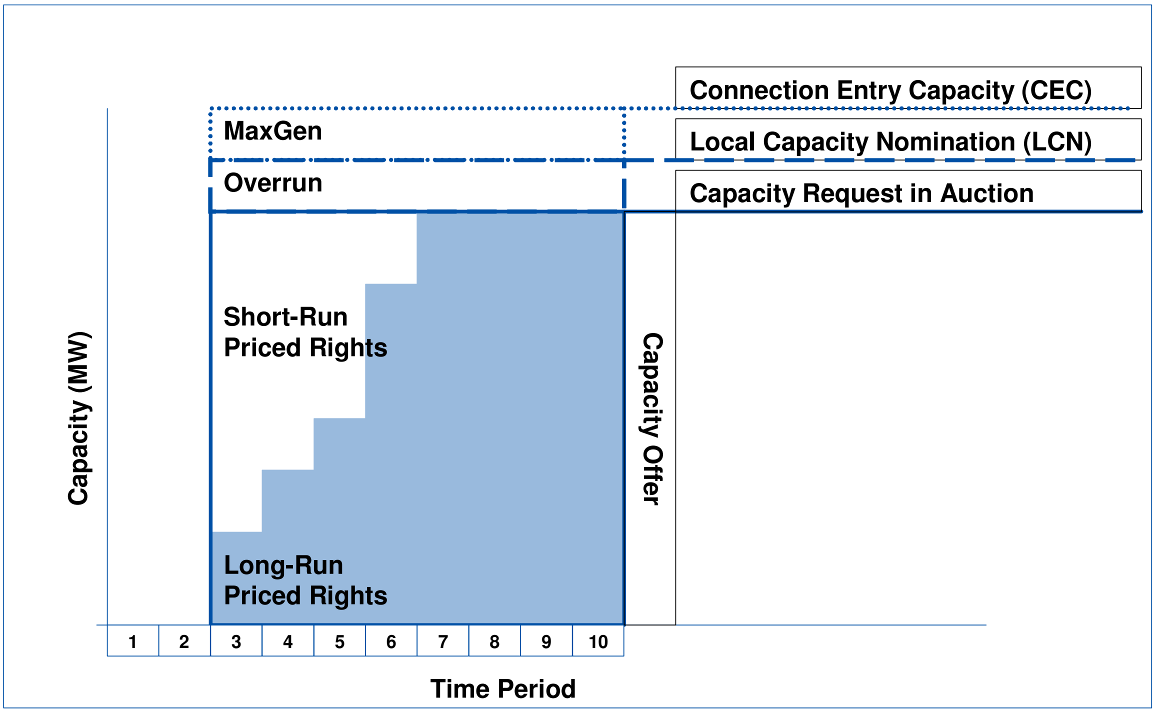
5.5.1.3 In this model an entry node means a point of connection for a power station onto the transmission system. These points of connection are currently represented by the Transmission Entry Capacity (TEC) in a Bilateral Connection Agreement (BCA).

5.5.1.4 The high level design concept, for WGAA3, would include the ability for parties to overrun their firm capacity allocation up to the level of the physical connection capacity (however defined).

5.5.1.5 In the first auction to be run according to these principles all existing physical access rights would be withdrawn and then re-allocated through that first auction. In future auctions any access rights that had already been allocated via previous auctions would not be “re-auctioned” in effect meaning that future auctions would be for unsold or incremental capacity only.

5.5.1.6 In auction rounds where the demand for access rights exceeds the actual physical capability of the transmission system then the rights that are available will be pro-rated according to the Users Bids. For example should there be 500MW of physical capacity available and 4 Power Stations each Bid for 250MW then each of those Power Stations will receive 125MW of capacity based on the long-run price and 125MW of capacity based at the short-run price.

5.5.1.7 To summarise diagrammatically a User would have the expectation of firm rights allocated as follows:



5.5.2 **Pro-Ration of Existing Rights**

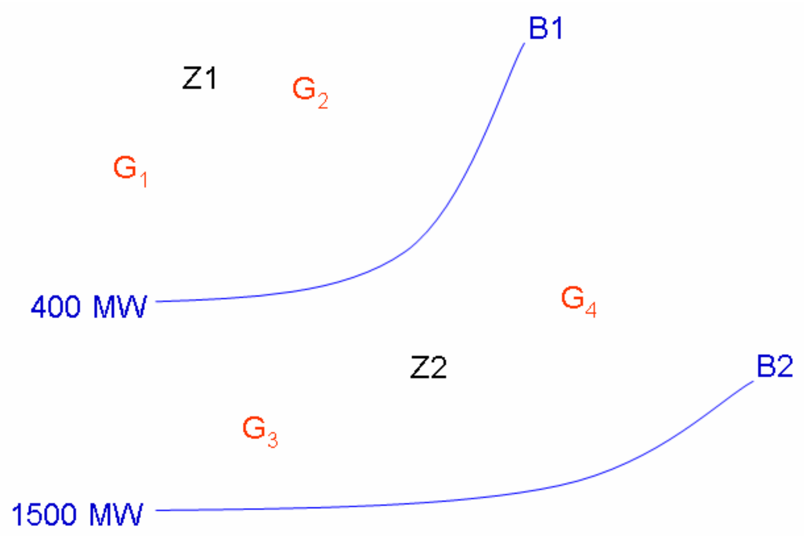
5.5.2.1 As noted above, in the first auction to be run according to these principles all existing physical access rights would be withdrawn and then re-allocated through that first auction. In the first year if demand for existing rights is greater than those that are physically available in any given year being auctioned then a pro-ration process will come into effect.

5.5.2.2 The general philosophy is that the most onerous constraint is determined first and each generator behind that constraint has an equally pro-rated volume of long-run priced access allocated to it. That pro-rating is then fixed for the next most onerous constraint that remains to be allocated and so on, until all constraint boundaries have been allocated.

5.5.2.3 The following examples demonstrate how this would occur in practice.

Two Zone Example

5.5.2.4 In this simple example there are two zones each with two generators behind them.



Generator	Requested Capacity	Long-Run Allocation
G1	400	-
G2	400	-
G3	1200	-
G4	1200	-

5.5.2.5 Boundary B1 has a transfer capability of 400MW and 800MW of requested capacity => 50% scaling factor.

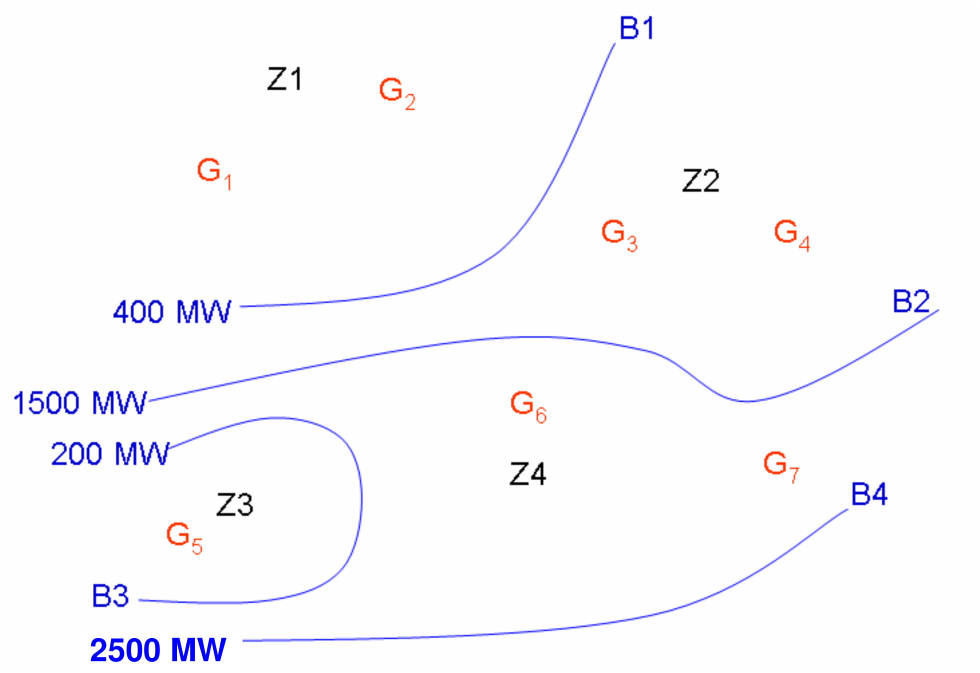
5.5.2.6 Boundary B2 has a transfer capability of 1500MW and (400+400+1200+1200) = 3200MW of requested capacity behind it => 46.875% scaling factor. Thus B2 is the most onerous boundary constraint and so every generator behind it gets pro-rated at this rate

Generator	Requested Capacity	Long-Run Allocation
G1	400	188
G2	400	188
G3	1200	563
G4	1200	563

5.5.2.7 From this stage on any further optimisation of less onerously constrained boundaries below B2 would be assessed with the outputs of G1 – G4 fixed at the values above which would not then be subject to any further pro-ration.

Four Zone Example

5.5.2.8 In this more complex example there are four zones with seven generators within them.


B1
Z1
G2
G1
Z2
G3
G4
400 MW
B2
1500 MW
G6
200 MW
Z4
G7
B4
Z3
G5
B3
2500 MW

Generator	Requested Capacity	Long-Run Allocation
G1	400	-
G2	800	-
G3	400	-
G4	500	-
G5	400	-
G6	200	-
G7	200	-

5.5.2.9 Boundary B1 has a transfer capability of 400MW and (400+800) = 1200MW of requested capacity behind it => 33.33% scaling factor.

5.5.2.10 Boundary B2 has a transfer capability of 1500MW and (400+800+400+500) = 2100MW of requested capacity behind it => 71.43% scaling factor.

5.5.2.11 Boundary B3 has a transfer capability of 200MW and 400MW of requested capacity behind it => 50% scaling factor.

5.5.2.12 Boundary B4 has a transfer capability of 2500MW and (400+800+400+500+400+200+200) = 2900MW of requested capacity behind it => 86.2% scaling factor.

5.5.2.13 From this first assessment it is apparent that Boundary B1 is most constrained and therefore G1 and G2 are both pro-rated by 33.33%.

Generator	Requested Capacity	Long-Run Allocation
G1	400	133.3MW
G2	800	266.67MW
G3	400	-
G4	500	-
G5	400	-
G6	200	-
G7	200	-

5.5.2.14 With G1 and G2 pro-rated to these capacity allocations the remaining three boundaries are reassessed.

5.5.2.15 Boundary B2 has a transfer capability of 1500MW and (133.33+266.67+400+500) = 1300MW of requested and pro-rated capacity behind it => unconstrained.

5.5.2.16 Boundary B3 has a transfer capability of 200MW and 400MW of requested capacity behind it => 50% scaling factor.

5.5.2.17 Boundary B4 has a transfer capability of 2500MW and (133.33+266.66+400+500+400+200+200) = 2100MW of requested and pro-rated capacity behind it => unconstrained.

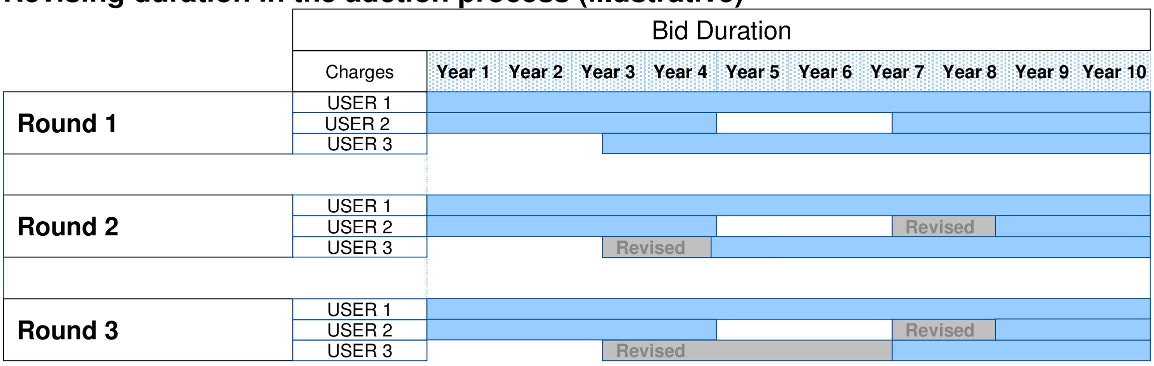
5.5.2.18 The only remaining constrained boundary is Boundary B3 and so generator G5 is pro-rated by 50%. All other generators receive their full requested allocation however.

Generator	Requested Capacity	Long-Run Allocation
G1	400	133.3MW
G2	800	266.67MW
G3	400	400MW
G4	500	500MW
G5	400	200MW
G6	200	200MW
G7	200	200MW

5.5.3 The Auction Process

5.5.3.1 As part of WGAA3 the multi round auction process would be a based on Users bidding a capacity (MW) and duration (years) for each node where capacity is required. The opening bid in the first round of the auction should represent the maximum capacity and longest duration required at the node. The structure of bids in terms of duration over different rounds is illustrated below.

Revising duration in the auction process (illustrative)



5.5.3.2 It should be noted from the above that there is no requirement on bidders to submit bids for consecutive years. The model enables Users to bid for capacity (MW) for an initial period and a subsequent period. After each auction round Users have the opportunity to vary the capacity and duration.

5.5.3.3 The WGAA3 auction could close when there are no “significant changes” to the volume or duration of bids received across three consecutive auction rounds. “Significant changes” could mean, for example:

- Aggregate Users bids do not differ in each round from a fixed percentage (perhaps 5%) of volume; or
- Aggregate Users bids do not reduce by a fixed de minimis volume change (perhaps 10MW reduction); or
- bids do not differ in duration by more than say 2 years.

5.5.3.4 “Significant changes” could be established by reference to the material impact on the transmission system in relation to transmission investment and could vary around the network based on a transparent methodology for establishing them. The closure mechanism will be set out in a methodology prior to the auction start so that Users can understand how the auction will close.

5.5.3.5 Following the closure of the auction, the GBSO will prepare an offer for each User for each bid at a node. The offer will set out the connection capacity and the liability for short run or long run charges. The offer will also include a bilateral connection agreement (BCA).

5.5.4 The Allocation Process – deriving charges

5.5.4.1 As part of WGAA3 the GBSO would evaluate all bids received and pro-rate to transmission system capability. This could be done with a boundary constraint or a full nodal model of the transmission network.

5.5.4.2 The modelling process would be based on the forecast state of the network taking into account planned and expected reinforcements over the duration of the modelling period. This will require certain assumptions to be made about the state of the transmission network and expected flows from nodes that may not have firm capacity or nodes that may be developed over the period of the planning horizon. For certain nodes or zones the model may assume that the system is unconstrained. For other nodes the system may be constrained.

5.5.4.3 The modelling process would use as the “background conditions” those Users that have “firm” booked transmission access rights allocated through previous auctions.

5.5.5 Long Run Pricing

5.5.5.1 The WGAA3 model would produce a series of cost-reflective tariffs derived for each node for each year that are designed to recover the long run marginal costs associated with investment on the GB transmission system. These charges would comprise the following:

- Nodal Local charge (£/MW)
- Nodal positive or negative locational tariffs (£/MW) which may be similar in certain zones
- Residual non locational charge for all Users which could be capacity (£/MW) based or output based (£/MWh)

5.5.5.2 For any User that triggers new investment (both new entrants and Users that “return to service”) the long run charges would apply once the investment in wider transmission works have been completed subject to completion of local works.

5.5.6 Long-Run Charges

5.5.6.1 The long-run charges are then calculated annually according to the following formula:

(Total Long-Run Capacity held in a given Year) × (Long-Run Tariff)

5.5.7 Short Run Prices

5.5.7.1 At certain nodes there may be insufficient capacity planned or projected to meet the wider User requirements on the transmission system. It is proposed with WGAA3 that for these nodes the GBSO would derive a cost reflective charge that reflects the short run marginal costs for allowing Users to access the transmission system prior to the completion of the associated wider works. These short run marginal costs result from the completion of local works ahead of wider transmission reinforcements that are required to ensure GBSQSS compliance. The short run charges may apply to all or part of the capacity at a node for a defined period. It is expected that the short run constraint charges would fall away once any required reinforcement is completed. Nodes subject to short run costs would also be subject to the nodal local charge (£/MW).

5.5.7.2 It should be noted that the short run costs at nodes would not reflect wider constraint costs on the transmission system that occur as a result of transmission outages or other transmission related requirements. These costs would continue to be recovered through non locational BSUoS.

5.5.7.3 The Working Group reached the consensus position that the preferred pricing approach would be to adopt a £/MWh price that would be charged when a constraint was active. This approach, the Working Group felt, would provide the most appropriate signal to minimise generation that utilises short-run priced access and would also be most easily priced into the energy market decisions to be taken by Users when considering whether to generate using short-run priced rights.

5.5.7.4 The final form of the short-run price will be further developed by National Grid and will ultimately be determined through a charging consultation.

5.5.8 Short Run Charges

5.5.8.1 The next stage for short-run pricing is to determine the overall charge that will be levied on any Users of short-run priced access rights. The price determined above is closely linked with the volume of generation output against which the price is levied in real time.

5.5.8.2 The first point to note is that it is anticipated that the short-run price in a given zone will only be levied in those settlement periods where there is an export constraint that is active due in whole or in part to output from Power Stations in that zone.

5.5.8.3 Secondly the volume against which the short-run price could be levied in these circumstances needs to be determined. In the case of this Working Group alternative amendment this volume is all output from generation in an "active" zone that is above those power stations long-run priced rights. In such cases clearly the price would need to be set ex-ante against the forecast annual total of such output in constrained zones.

5.5.9 Short-Run Over- / Under-Recovery

5.5.9.1 In the event that short-run prices are set ex ante, it is likely that these prices and/or volumes will differ from actual costs and/or volumes and that this would result in either an over or under recovery by the GBSO of short run costs from Users. It is proposed that the revenues received through Users of short-run priced access rights would be offset against BSUoS charges and so it follows that any over- or under-recovery of the short-run costs would be socialised across all BSUoS payers.

5.5.9.2 As a further consideration the short run charges operate as an important signal to Users as to whether to acquire firm long-term access or acquire short-term firm rights or Overrun with exposure to short term costs. Understanding the short run costs (and the over and under recovery mechanism) is therefore vitally important for Users (this is true of any auction design model). The WGAA3 capacity and duration approach may offer Users the ability to fix or hedge these costs, perhaps through a contract for differences (CFD), to enable the User to manage effectively and efficiently the risk associated with firm/non firm transmission capacity holdings.

5.5.10 **Validation Run**

5.5.10.1 To disincentivise the "over-booking" of capacity by Users in an attempt to maximise their share of any pro-rated long-term priced access rights, it is proposed that the following process be incorporated within the CUSC to validate the fact that Users' Power Stations are capable of utilising their full access rights (both long-run and short-run priced access rights). This validation will be through the following process which varies according to whether a generator is "new" or "existing":

5.5.10.2 Stage 1: (New generators): The evidence provided to National Grid through the construction & commissioning process will be used to validate the fact that the Power Station's installed capacity is in line with that which it has booked through the auction process. Should satisfactory evidence not be forthcoming then the existing provisions of CAP150 will be used to withdraw such access rights from the generator and to re-allocate them amongst the remaining generators within the same zone that competed against the CAP150 affected generator in that zone.

5.5.10.3 Stage 1: (Existing generators): For the first year following an auction the output of generating units within the Power Station will be monitored to ensure that they are operational and thus in theory capable of generating up to their capacity.

5.5.10.4 Stage 2: (Existing Generators): Should one or more Generating Units be on outage throughout the first year, a User will be asked to provide evidence that it has in place a programme of work to bring the unit(s) back into service. If necessary the opinions of an Independent Engineer will be sought.

5.5.10.5 Stage 3: (Existing Generators): Should there still be doubt as to the capability of the Power Station and National Grid signals to the User that it intends to reallocate pro-rated capacity then the User will have the opportunity at this stage to appeal to the Authority for a determination.

5.5.10.6 Stage 4: (Existing Generators): The final course of action will be for the generator to undertake a proving run at its own expense to demonstrate that a generating unit(s) which is subject to validation is in fact operational.

5.5.10.7 Should an existing generator fail to prove its capability to utilise its full capacity then National Grid will re-allocate its capacity to that which it reasonably believes the Power Station is capable of utilising. This capacity shall then be pro-rated according to the auction rules and any long-run priced capacity released by this exercise will be reallocated to those Users who also booked capacity in the same auction as the generator whose rights are being reallocated. For the avoidance of doubt this reallocation only applies to the period in which the Users long-run priced access rights have been pro-rated. National Grid would continue to construct and hold the User liable for the long-run priced access rights which have not been pro-rated in future years.

5.5.11 Treatment of Overrun

5.5.11.1 The concept of overrun is compatible with this model (noting that CAP162 would need to be approved by the Authority for the concept of overrun to become a part of the arrangements for allocating transmission access). As indicated in the diagram above in section 5.5.1 any output above a User's level of combined long-run priced and short-run priced access rights would be liable for an overrun charge.

5.5.12 Trading and Sharing of Access Rights

5.5.12.1 It is envisaged that the long-run priced element of access rights under this model would be fully tradeable and/or shareable. The short run priced element would not be tradeable or shareable however.

5.5.13 Design Variation Connections

5.5.13.1 The arrangements under a capacity and duration auction process are capable of recognising the implications of Users with design variation connections for revenue recovery. This can be achieved by ensuring that the tariffs that are offered to such Users reflect the lower investment costs at the node for such Users. Furthermore, if appropriate the applicable tariffs could also reflect arrangements where the User is subject to transmission capacity reductions in circumstances where circuits nominated in the connection agreement are unavailable (It is not clear how any simultaneously cleared auction would address this issue).

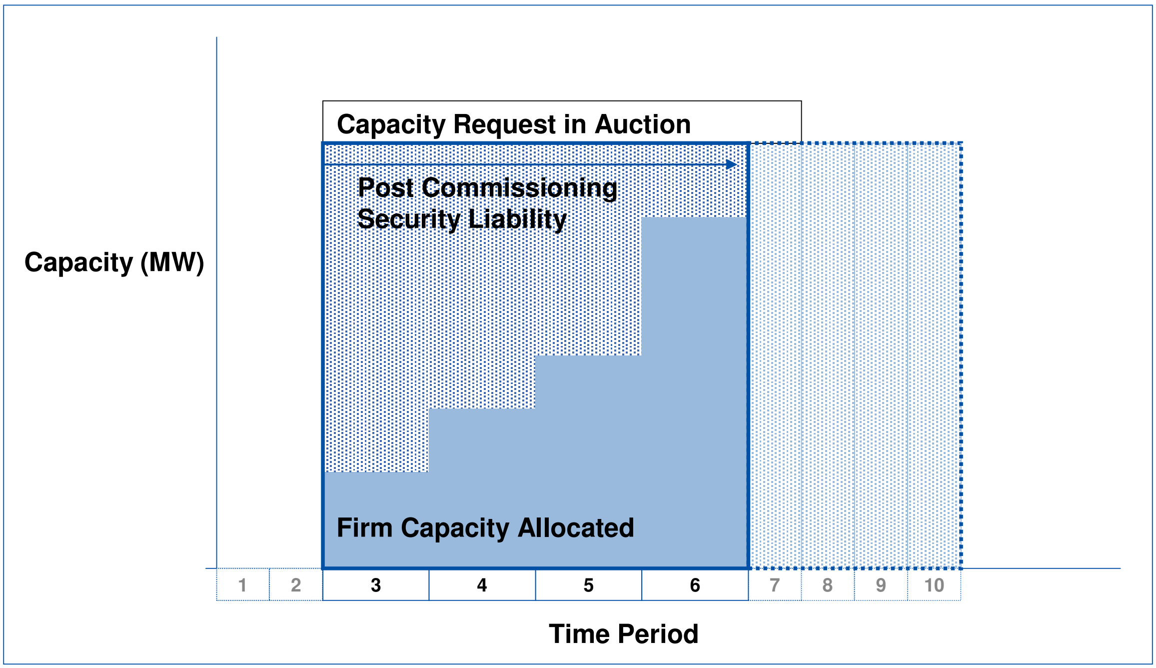
5.5.13.2 Items that require consideration in relation to design variation connections include:

- The commercial and contractual framework in relation to the liability to pay for the short run charges for Users with design variations;
- The nature of any transmission specific restrictions for Users with design variation connections; and
- The implications of intertrips and other operating restriction on design variation connections in a capacity and duration auction

5.5.14 Securities

5.5.14.1 It is proposed, as part of WGAA3 that under the capacity and duration model pre commissioning liabilities would be managed through the connection agreement. Therefore if Users do not complete their works (i.e. build a power station) then they cannot connect to the transmission system and are liable for any “stranded” costs. This reflects the fact that stranded costs only occur if the User cannot complete its works and a connection agreement is terminated.

5.5.14.2 An important characteristic of the security arrangements under WGAA3 would be that the securities provided under final sums would be linked to the completion of the assumed wider reinforcements (at the time that the allocation is made) and not upon energisation (as is the case currently as the completion of wider reinforcements is the pre-condition to energisation). Instead the securities for wider reinforcements would progressively reduce as they are delivered potentially post-energisation and would fall away completely once a User has reached the point where all of its access rights are long-run priced access rights. Diagrammatically this is as follows:



5.5.14.3 The nature of final sums arrangements with regard to security for transmission investment works is similar to the existing final sums methodology. These final sums would be cost reflective and identified as part of the auction process. Once a User has committed to pay the associated tariff then the final sums should be fixed until such time as the User connects. This would enable the GBSO/TO to ensure that appropriate security is in place.

5.5.14.4 The use of cost reflective final sums would enable negative tariff nodes or zones to be treated on the same basis as all other nodes (avoiding any discrimination). This would also ensure that appropriate security arrangements would be in place for any transmission works (local or wider) in negative tariff zones.

5.5.14.5 It should be noted that where Users can use the system without a requirement for any transmission reinforcement that there would be no need for any liabilities with regard to security for new investment.

5.5.15 Impact of proposed Security Arrangements on Users

5.5.15.1 It should be noted that for the first auction round all existing rights (pre-commissioning or post-commissioning User) are withdrawn and re-allocated to all Users that wish to secure them. This may lead in some cases to Users (pre or post commissioning) receiving pro-rated rights along with Users that are allocated rights in the auction in advance of certain transmission system reinforcements being completed. In this event all Users will also become liable for the cost-reflective final sums for their share of the liabilities being incurred through the construction of new transmission system assets.

5.5.15.2 Preliminary analysis taken forward through the assessment of CAP166 indicates that given current demand for transmission access rights all Users behind transmission system boundary B9 (see ANNEX 3 – INITIAL ANALYSIS OF AUCTION BOUNDARIES for further detail) would be subject to some pro-ration and so are likely to become liable for cost reflective final sums.

5.5.16 Impact on Users connected to the transmission system

5.5.16.1 This section considers the potential impact of the WGAA3 capacity and duration auction model on existing and potential Users connected to the transmission system. The auction process gives the Users the opportunity to fix (hedge) the long run and short run costs of using the transmission system. This provides effective risk management which should result in an efficient and economic solution (subject to resolution of the over and under recovery issues).

5.5.16.2 From the perspective of different types of User the WGAA3 capacity and duration model has the following implications

- Existing User: The proposed arrangements would replace the existing obligations under the CUSC with regard to charging liabilities and rights to use the transmission system. Existing Users (be it that they are a current (commissioned) generator or a generator with a signed Bilateral Connection Agreement but not yet commissioned) would be required to bid in the first round alongside Users that wish to use the system in the future. Note rights removed as well;

- Incremental Capacity: For existing Users that are seeking incremental capacity at a node where there is no requirement for additional wider transmission investment the charges would be based on the long run costs associated with the node.

- “Return to Service”: Under the capacity and duration model existing Users can book a limited duration of transmission access then take an outage period and subsequently return to service. However, the bid to return to service would be treated on the same basis as a new entrant since the existing capacity may have been allocated to another User. Therefore there may be an investment required in transmission reinforcement which may delay a firm allocation. During this investment period, the existing User could be exposed to the short run costs if it wishes to use the system.

- New Capacity: New Users would be able to bid for new firm transmission capacity in the auction process. Any offer would take into account the investment period required. If the local and wider works can be aligned then the User can use the system with firm long term transmission connection rights from the date that the works are completed.

- "Connect and Manage": In certain circumstances, the GBSO/TO may be able to complete local works ahead of wider reinforcement works. In this case, the User can opt to complete on the basis of local works, subject to the short run costs. These short run costs would be applicable until such time as the wider reinforcement works are completed. This approach is analogous to the "Connect and Manage" arrangements currently under consideration in CAP164.

5.5.17 **Impact on GBSO/TO**

5.5.17.1 From the perspective of the GBSO and TOs, the User acceptances form the basis for revenue recovery with firm capacity charges recovering the long run marginal cost of investment in the transmission system and the constraint charges recovering the ex ante estimated short run constraint costs.

5.5.17.2 An over and under recovery mechanism is required to ensure revenue adequacy; which is the recovery of actual costs where they vary from the fixed LRMC and SRMC charges. There are a number of different options for the design of such a mechanism:

- LRMC under/over recovery could be addressed through adjustments to non locational residual;

- SRMC under/over recovery could be addressed through non locational BSUoS or

- SRMC shortfall recovery through zonal locational BSUoS or

- User specific relief from £/MWh SRMC cost in the event that the constraint costs are less than forecast

5.5.17.3 The WGAA3 capacity and duration model will have clear implications for the SO and TOs in relation to their licensed activities and their transmission price control. For example, any arrangements that fix revenues from Users whether in the form of short run or long run charges will have an impact on the amount of revenue recovery. In addition, there may be a requirement to introduce new incentive arrangements on the GBSO and or TOs in relation to short run costs and long run transmission investment. The price control and Licence may, therefore, require revision to enable the new arrangements to be implemented.

6.0 ASSESSMENT AGAINST THE APPLICABLE CUSC OBJECTIVES

6.1 The Working Group performed an initial assessment of CAP 166 original, WGAA1 and WGAA2 against the applicable the CUSC Objective(s);

(a) the efficient discharge by the Licensee of the obligations imposed upon it by the act and the Transmission Licence; and

(b) facilitating effective competition in generation and supply of electricity and facilitating such competition in the sale, distribution and purchase of electricity.

6.2 The results of this assessment are summarised in the table below.

<table>
<tr><th>Type of Auction</th><th colspan="3">Price Based
(SO indicates capacity availability and allocation is then based on price)</th><th>Capacity/Duration
(SO provides price signals in response to capacity requirements)</th></tr>
<tr><td></td><td>Original</td><td>WGAA1</td><td>WGAA2</td><td>WGAA3</td></tr>
<tr><td></td><td>Auctions of zonal capacity</td><td>Boundary Constraint Allocated at Nodes</td><td>Boundary Constraint Allocated at Nodes with Reserve Prices</td><td>Users bid capacity requirement over a number of years</td></tr>
<tr><td colspan="5">Efficient discharge of licence conditions</td></tr>
<tr><td rowspan="3">Promotes</td><td>Discovery of value of transmission access capacity and temporal nature of long-term capacity bookings would give improved investment signals</td><td>As an auction design it may have merit but it is complicated and without testing there is no indication that it is a more efficient allocation of capacity than currently</td><td>As an auction design it may have merit but it is complicated and without testing there is no indication that it is a more efficient allocation of capacity than currently</td><td>Implicit discovery of value of transmission access capacity (via Users' response to pricing signals) and temporal nature of long-term capacity bookings would give improved investment signals</td></tr>
<tr><td>As an auction design it may have merit but it is complicated and without testing there is no indication that it is a more efficient allocation of capacity than currently</td><td></td><td>Reserve pricing allows for locational pricing signals to be retained within the auction framework</td><td></td></tr>
<tr><td colspan="4">Provision of Information re requirement of capacity rights at the same time should enable the SO to plan the system in a more coordinated way than under current arrangements. However, there could be a delay to individual User's plans due to needing to wait for auction process to signal rights.</td></tr>
</table>

Type of Auction	Price Based (SO indicates capacity availability and allocation is then based on price)			Capacity/Duration (SO provides price signals in response to capacity requirements)
	Original	**WGAA1**	**WGAA2**	**WGAA3**
Demotes	Results of the auction are driven by the initial allocation of zonal transmission access capacity which requires an assumption beforehand of the capacity that Users desire	Without testing poor bidding by inexperienced Users could result in less capacity release than the current baseline	Without testing poor bidding by inexperienced Users could result in less capacity release than the current baseline	Ex-ante nature of prices could lead to an over/under recovery of revenue which could create a cross-subsidy
	The over/under recovery of revenue creates a cross-subsidy	The over/under recovery of revenue creates a cross-subsidy	The over/under recovery of revenue creates a cross-subsidy although less of an issue with reserve prices.	Potential for Users to factor the short-run costs into BM which would lead to an increase in constraint costs
	Without testing, poor bidding by inexperienced Users could result in less capacity release than the current baseline			Without testing poor bidding by inexperienced Users could result in less capacity release than the current baseline
	Based on the assumption that Users do not have existing rights which, if Users are unsuccessful in the auction, would lead them to withdraw their plant earlier than planned; thus endangering (a) the security of electricity supplies and (b) the maintenance of the reliability, safety & operation of the electricity grid system; plus it's economically inefficient (to close plant due to failure to obtain access)			Users are provided with the access rights for which they have bid in the Auction, but in reality any access above the physical capability of the system could be subject to being constrained off. This may lead Users to withdraw their plant earlier than planned; thus endangering (a) the security of electricity supplies and (b) the maintenance of the reliability, safety & operation of the electricity grid system; plus it's economically inefficient (to close plant due to failure to obtain access)
Facilitates competition				

Type of Auction	**Price Based (SO indicates capacity availability and allocation is then based on price)**			**Capacity/Duration (SO provides price signals in response to capacity requirements)**
	Original	**WGAA1**	**WGAA2**	**WGAA3**
Facilitates	Existing and new generators could compete for transmission access equally, with rights allocated to those that valued them most highly	Allows open participation	Allows open participation	Allows open participation
	Existing capacity could be reallocated with certainty to new entrants as a result of firm bookings		An approximation of both the long and short run marginal costs of the transmission system can be factored into the price of transmission access through the Reserve Price. Ensures that Users have costs appropriately targeted where over allocation of baseline capacity occurs.	Users are able to respond to pricing signals provided by the SO as part of the auction.
	Enhanced transparency		Greater Transparency for Users than offered by Working Group Alternative 1.	Transparency of pricing information revealed through auction rounds.
Frustrates	Security of Supply is at risk if the auction includes incumbent generators as they could lose all their rights			Incumbent generators are likely to get a pro-rated amount of rights, which may have some impact on security of supply
	The complexity of the auction may give an advantage to large players			Complexity of the information provision by Users could be seen as a barrier to entry and could favour the bigger players.
	Complexity of the auction could lead to larger players having an inherent advantage over smaller players as they will be able to devote dedicated resources to the auction process that smaller players may not. Also larger players may be able to smear the transaction costs of participation in an annual auction over a number of sites whereas smaller players may have many fewer sites across which to allocate these.			
	Based on the assumption that Users do not have existing transmission access rights, which undermines investor confidence and increases the regulatory risk premium placed by Users operating in the GB market, leading to higher consumer prices			

Type of Auction	Price Based (SO indicates capacity availability and allocation is then based on price)			Capacity/Duration (SO provides price signals in response to capacity requirements)
	Original	WGAA1	WGAA2	WGAA3
	New capacity would be allocated but with no certainty for holders as to the nature of that capacity (which could be changed or removed) in the future			
	Although an auction based allocation allows Users to compete in the first year, once a User has procured long term transmission access capacity it retains this capacity for the duration of its booking. Other new Users in future years will not be able to compete with the incumbent for this capacity only signal that they wish new capacity to be built (if none remains).			
	In removing the existing transmission access capacity of Users and reallocating it (via the GBSO) it removes the ability for Users to trade on their capacity (as now) if the economic signal exists plus its also economically inefficient (to close plant, due to failure to obtain access, rather than via an energy market signal) which damages competition			
	Fixed Price elements of both for locational charges inevitably results in additional volatility elsewhere (residual charges) in order to maintain cost-reflectivity. This volatility of prices could result in reduced market entry resulting in reduced competition. Fixing prices also will result in winners and losers as those that have fixed prices in earlier years may be at an inherent disadvantage or advantage to new Users by virtue of the assumptions made when they first connected. Again this could act as a barrier to effective competition as two otherwise identical generators find they have different cost bases against which to offer services to the market and National Grid.			

7.0 TRANSITIONAL PROCESSES AND PROPOSED IMPLEMENTATION

7.1 Transitional Processes

7.1.1 The transitional processes required are:

7.1.2 **LCN Transition:** A process will be needed to grant all existing Users an LCN MW level and a LCN Effective Date. This process will be very similar to that enshrined within the other transmission access proposals (CAP161-CAP165) that also utilise the concept of an LCN.

7.1.3 **Financial Securities (Original, WGAA1, WGAA2 only):** Should any of the CAP166 Original Amendment, WGAA1 or WGAA2 be approved then Users will need to notify whether they wish to move onto the system of securities introduced by such variants or whether they wish to remain on the “pre-CAP166” system of securities.

7.1.4 **Auction Transition:** The process steps required to establish and run the first auction to allocate long-term transmission access rights will need to be fully developed.

7.2 Implementation Dates

7.2.1 The Working Group proposes that CAP166 should be implemented on a 1st April at least eighteen months after an Authority decision. The 1st April date is driven by the annual charges for entry capacity, which apply from the 1st April each year. Taking into account the time required to develop and test the IT system that would be required to implement the amendment and also to allow Users the opportunity to apply for a LCN in advance of the new auction processes commencing, the Working Group believes that there should be a 16-18 month lead time from a decision by the Authority and implementation of the associated changes. It should be noted that this lead time is based on indicative analysis only, and further work is required to establish a more accurate lead time.

7.2.2 In order that transmission access rights may be allocated by an auction and then from the 1st April in the year following such an auction, Power Stations may operate in accordance with these rights, the transition process outlined in 4.1.4.41 above would require an Authority decision in advance of the 1st December, 16 months prior to the 1st April "Go-Live" date.

7.2.3 By way of example for a 1st April 2011 "go-live date", a transitional process would need to come into effect from 1st December 2009 that would permit existing generators and any new applicants to submit an LCN application. National Grid would then need to prepare LCN offers that would act as the pre-cursor to entry into the first auction to be held in September 2010. Only those Users who had accepted their LCN offer by 1st June 2010 (or who had referred this offer by 1st June and subsequently accepted it prior to 15th August 2010) could participate in the first auction.

7.2.4 Similarly for an April 2012 "go-live date", a "go-active date" of 1st December 2010 would be required.

7.2.5 Clearly implementing the amendment 16 months in advance of the first auction would just allow the LCN transition process to be completed. However to allow Users further time to develop their LCN applications the Working Group felt it more prudent to allow an eighteen month lead time in which from a decision from the Authority to the time where Users operate using transmission access rights procured via a CAP166 auction.

7.2.6 National Grid suggested that implementation should not be restricted to these two specific dates, but should instead be open-ended, such that implementation was on the first 1st April at least eighteen months after an Authority decision, whenever that was.

7.2.7 The majority of Working Group members believed that implementation should be fixed as being on either of the two specific dates identified above. They believed that the Authority should not require more than 18 months to reach a decision (assuming that a final CAP166 Amendment Report is submitted to the Authority in March 2009), especially given the urgency of the Transmission Access Review timetable that has been impressed on the industry. To permit later implementation dates, it was argued, would be to prolong the regulatory risk faced by both existing plants and new entrants, and would introduce the possibility that, by the time a decision was reached, the reasons for, and parties' views and assessment of, the amendment may have changed.

7.3 Implementation

7.3.1 The Working Group noted that due to the risks presented by the development of the IS infrastructure necessary for an auction of the type proposed by CAP166 and its Alternates, CAP166 could be implemented such that the soonest long-term access could be allocated by auction for the first time would be for Financial Year 2011/12. However there remained a possibility that implementation would have to be delayed a year allowing long-term access to be allocated by auction for the first time for Financial Year 2012/13. By way of examples, this may be as a result of for instance:

- The rules for the auction process may be such that it is not possible for any algorithm to meet the objective of the rules.
- If it is possible, then there is a risk that a suitable algorithm may not be developed in time.

7.3.2 The Working Group therefore recommended that an Implementation Group be established whose purpose would be to oversee the implementation of all aspects of CAP166 implementation including both National Grid's IS system developments and Users' IS System developments and judge for which Financial Year long-term access could be first auctioned for and would pass their views to the CUSC Panel by a certain date who would then make the final decision for which financial year any approved auction arrangements should apply, subject to an Authority decision to veto.

8.0 IMPACT ON IS SYSTEMS

8.1 The conclusions of National Grid's initial IS impact assessment for the Original Amendment and the Working Group Alternative Amendments are summarised below. These conclusions are <u>indicative</u> only and are subject to change following further analysis.

8.2 Costs are identified as falling into one of three broad categories (less than £500k, £500k to £1m, and £1m to £5m). Timescales are indicated by stating whether or not the necessary systems can be delivered in time (for an assumed "first run" date) given various starting dates for the projects to deliver the systems. This approach has been followed for all of the CAPs in the TAR suite in order to provide consistency.

8.3 For CAP166 three systems are likely to dominate the costs and timescales for IS developments. These are:

1. The auction system for communication between National Grid and bidders. It is likely, although not certain, that this would be procured from an external supplier. The anticipated timescales for procurement and development of such a system make delivery before December 2010 highly unlikely.

2. The optimisation algorithm for allocating the TEC based on the bids received. The complexity of this algorithm will depend upon the auction rules agreed by the industry. Some of the issues relating to the algorithm required for the Original, WGAA1, and WGAA2 are highlighted in points a to d below. The requirements for WGAA3 are not yet certain. However, it has be assumed that an algorithm of some kind will be required for both.

a. Experience shows that implementation of such optimisation algorithms (even using commercially available packages) can be difficult. Furthermore, the results produced by the optimisation algorithm may require a long period of scrutiny by the industry before being deemed acceptable.

b. In particular it should be noted that issues such as the feasibility of the problem being solved, the optimality of the solution, and the possible degeneracy of the solution can often present difficulties. Resolving such difficulties can increase development time and may require discussions with the industry in order to find acceptable resolutions.

c. At this stage it is very difficult to estimate the timescale and cost for developing the algorithm. The algorithm required for the Original is thought to be simpler than that required for WGAA1 or WGAA2 and this is reflected in the cost estimates. The delivery of a suitable algorithm (for the Original, WGAA1, or WGAA2) by December 2010 might be possible. However, some compromises might be necessary to meet this date. These compromises might need to be reflected in the rules of the auction and agreed with the industry.

d. Cost and licencing issues will need to be addressed when considering provision of a copy of the optimisation algorithm to bidders.

3. The system for charge calculation and settlement. Some of the options proposed as part of WGAA3 might require some charges to be calculated daily and settled daily a number of days in arrears. Provision of a system capable of daily charge calculation and daily settlement could be time consuming and costly.

8.4 A high level summary of the systems required for the Original, WGAA1, WGAA2 and WGAA3 is given in the table below.

	Auction system	Algorithm	System capable of daily charge calculation and daily settlement
Original (Zonal)	•	•	
WGAA1 (Nodal)	•	•	
WGAA2 (Nodal + reserve price)	•	•	
WGAA3 (Capacity and duration)	•	•	•*

* only required for some options

It should be noted that there are a number of areas in which the required functionality is not yet clear. Where this is the case no attempt has been made to assess the impact on IS systems. Examples include:

1. Calculation of cleared prices (possibly required for the Original, WGAA1, and WGAA2).

2. Identification of the settlement periods in which each constraint is active (possibly required for WGAA3). Provision of a system to do this could be time consuming and costly.

8.5 Delivery and cost estimates for Original, WGAA1, WGAA2 and WGAA3 are given in the table below.

	Assumed date of decision by the Authority	First run	Months available if work begun after the Authority decision	Months available if work begun in Dec-08	Deliverable if work begun after Authority decision?	Deliverable if work begun in Dec-08?	<£500k	£500k - £1m	£1m - £5m
Original (Zonal)	Jun-09	Dec-10	17	23	NO	YES		•	
WGAA1 (Nodal)	Jun-09	Dec-10	17	23	NO	YES			•
WGAA2 (Nodal + reserve price)	Jun-09	Dec-10	17	23	NO	YES			•
WGAA3 (Capacity and duration)	Jun-09	Dec-10	17	23	NO	YES			•

Where the above table indicates that if work starts in December 2008 it is feasible to deliver the necessary systems in time for the stated first run date, it may be assumed that any delay to the start of work would lead to an equivalent slip in the first run date.

8.6 There are many limitations on the scope of this initial IS impact assessment. Examples include:

1. Only the impact on National Grid's IS systems has been assessed. The impact on CUSC parties' IS systems has not been assessed.
2. Only the costs of the projects required to deliver the necessary systems have been estimated. Additional run-the-business costs relating to IS systems are likely to be incurred, these have not been estimated.
3. There has been no analysis of any IS effort or systems required during the transition from the existing arrangement to the new arrangements.
4. Each CAP and each option associated with it has been assessed in isolation. The impact on time and cost of multiple projects running in parallel has been ignored.
5. National Grid has not assessed the work against its existing IS workload to assess resource availability.

8.7 A more accurate IS impact assessment for the Original Amendment and the Working Group Alternative Amendments would require a number of items which are not currently available. These include:

1. Definition of the business requirements for the Original Amendment and the Working Group Alternative Amendments in more detail than has been discussed by the Working Groups.
2. Confirmation of certain technical assumptions which have been made during the initial analysis.
3. Identification of the combination of CAPs 161-166 that is to be implemented and for each CAP that is to be implemented whether the Original Amendment or one of the Working Group Alternative Amendments is to be implemented.

8.8 Without prejudicing the decision of the Authority, National Grid intends to undertake further IS analysis between November 2008 and March 2009. This analysis will attempt to address point 1 above by making assumptions about the most likely detailed business requirements and will attempt to address point 2 by undertaking a number of feasibility studies. To address point 3 the analysis will consider the consequences a variety of possible combinations. The results of this analysis will be made available to CUSC parties and the Authority.

9.0 IMPACT ON THE CUSC

9.1 The impact on the CUSC would include, but may not be limited to, changes to Sections 2 (Connection), 3 (Use of System), 6 (General Provisions) and 9 (Interconnectors). There would also be consequential changes required to Section 11 (Interpretation and Definitions), and to the CUSC Schedules and Exhibits.

10.0 IMPACT ON INDUSTRY DOCUMENTS

Impact on Core Industry Documents

10.1 No impact on Core Industry Documentation has been identified.

Impact on other Industry Documents

10.2 Related modifications to the Use of System Charging Methodology are currently being prepared to ensure that any Charging Issues that may materialise should CAP166 or any of its Alternatives be approved.

10.3 Changes to the System Operator – Transmission Owner Code (STC) would be required in order that generators' long-term transmission access rights secured through auctions (and the expiry of such rights) are taken account of by Transmission Owners when planning to accommodate additional transmission capacity requests. Additional STC changes may be required to "back-off" in Scotland any other changes to National Grid's User facing obligations – specifically in the construction of incremental capacity supply functions.

10.4 If CAP166, WGAA1, WGAA2 or WGAA3 were to be approved changes to the SQSS may be appropriate. The GBSQSS Review Group has embarked on a major review of the GBSQSS, which will include consideration of this issue.

11.0 WORKING GROUP VIEW / RECOMMENDATION

11.1 The Working Group voted on whether they believed the original or the Working Group alternatives are **better than the current baseline**. The result of the vote is described in the following table:

Proposal	Better	Not better	Abstained
Original	0	13	0
WGAA1	0	13	0
WGAA2	2	11	0
WGAA3	2	11	0

11.2 Next the Working Group voted on whether they believed the original or the Working Group alternatives are **better than the original amendment**. The result of the vote is described in the following table:

Proposal	Better	Not better	Abstained
Original	-	-	-
WGAA1	1	8	4
WGAA2	3	6	4
WGAA3	4	8	1

11.3 The majority of the Working Group believed WGAA1 and WGAA2 were not better than the original or the baseline. The Chair of the Working Group with support of some members of the Working Group took forward WGAA1 and WGAA2.

11.4 The Working Group voted on which of the proposals they believe best facilitates the applicable CUSC Objectives. The result of this vote is described in the following table:

Proposal	Best
Original	0
WGAA1	0
WGAA2	2
Abstained	11

11.5 After the Working Group extension the Working Group voted again on which of the proposals they believe best facilitates the applicable CUSC Objectives. The result of this vote is described in the following table:

Proposal	Best
Original	0
WGAA1	0
WGAA2	0
WGAA3	3
Abstained	10

12.0 NATIONAL GRID INITIAL VIEW

12.1 Of the four options (the CAP166 original proposal, WGAA1, WGAA2 and WGAA3) contained within this consultation National Grid is supportive of WGAA2 and WGAA3 only.

12.2 National Grid is broadly supportive of both a price based and a capacity duration style of auction for allocating transmission access rights as it believes both will give the opportunity for User's who value access to the GB transmission system the highest, to obtain that access. National Grid views this against the existing system which can frustrate new Users who may value that capacity more highly than existing access rights holders but have no choice but to await new transmission infrastructure build rather than directly compete with existing access right holders.

12.3 However the two price based auction models presented by the original CAP166 amendment proposal and WGAA1 do not in National Grid's view better facilitate the applicable CUSC objectives. In the case of the original amendment this is down to the fact that there are significant interactions between zones which means that practically it is very difficult to define them other than if they are kept small. These small zones then have very few generators within them defeating the initial objective of allowing for the free sharing of TEC within them. Therefore the boundary model methodologies are clearly better than the zonal. WGAA1, though a boundary constraint model, does not have any concept of a reserve price within its methodology and it retains the existing levels of over-allocated TEC within the baseline capacity released. This effective removal of a reserve price and the signals to compete on volume would likely see a collapse in the auction price and in turn lead to significant areas of the existing transmission system being left with little or no locational pricing signal, which would not allow for a cost-reflective charging system to be retained.

12.4 This then leaves WGAA2 and WGAA3 as the options National Grid believes would better facilitate the applicable CUSC objectives if they were ultimately to be implemented. Both offer a mechanism by which parties who value rights more than others may procure them, either in the case of WGAA2 by outbidding others in an annual auction, or in WGAA3 by committing to purchase a volume of short-run priced rights where they effectively share additional "over-allocated" rights with others who are also willing to do so in advance of transmission system reinforcements.

12.5 In National Grid's view, both WGAA2 and WGAA3 require further development, in particular to the securities that form part of WGAA2 and to a lesser extent WGAA3. In the case of WGAA2 this will be to develop a set of arrangements to allow wider works to be securitised against Users, and in the case of WGAA3 to assess the effectiveness of the fixed cost reflective final sums methodology proposed. There is clearly also development work to be done for either WGAA2 or WGAA3 on fully working up a full SO Long Term Release Methodology that is compatible with the principles developed by the Working Group, an auction model and IS System that will allow Users to fully participate in the auction process and also the required charging amendments to be progressed under separate Charging governance. National Grid believes however that all of these items of further work, though complex can be taken forward to an appropriate conclusion should either WGAA2 or WGAA3 ultimately be approved by the Authority.

13.0 INDUSTRY VIEWS AND REPRESENTATIONS

13.1 Responses to the Working Group Consultation

13.1.1 The following table provides an overview of the representations received.

13.1.2 Copies of the representations are contained in Working Group Report Volume 2.

Reference	Company
CAP166-WGC-01	Association of Electricity Producers
CAP166-WGC-02	British Energy
CAP166-WGC-03	British Wind Energy Association
CAP166-WGC-04	Centrica
CAP166-WGC-05	Drax Power
CAP166-WGC-06	EdF Energy
CAP166-WGC-07	EON UK
CAP166-WGC-08	ESB International
CAP166-WGC-09	Fairwind (Orkney) Ltd
CAP166-WGC-10	First Hydro Company
CAP166-WGC-11	Fred Olsen Renewables
CAP166-WGC-12	GDF SUEZ
CAP166-WGC-13	Immingham CHP LLP
CAP166-WGC-14	Intergen
CAP166-WGC-15	Magnox North
CAP166-WGC-16	National Grid Electricity Transmission
CAP166-WGC-17	Renewable Energy Association
CAP166-WGC-18	RWE npower
CAP166-WGC-19	ScottishPower Energy Wholesale
CAP166-WGC-20	Scottish Renewables
CAP166-WGC-21	Scottish and Southern Energy
CAP166-WGC-22	Welsh Power
CAP166-WGC-23	Wind Energy
CAP166-WGC-24	Powerfuel Limited

13.1.3 The following table provides an overview of the WG Consultation Requests received. Copies of the representations are contained in Working Group Report Volume 2.

Reference	Company	Details of the proposal
CAP166 WGCR-01	National Grid Electricity Transmission	An Alternative based upon WGAA1 as set out in the report, but with the exception that the auctions are settled according to a Pay as Bid principle and not through a cleared price
CAP166 WGCR-02	National Grid Electricity Transmission	An Alternative whereby the baseline capacity released through the auction is greater than that which currently physically exists on the GB Transmission System, and where a locational reserve price is set in the auction to prevent this over-allocation of capacity allowing the auction prices to collapse towards £0/kW. This request would apply across each of the original and any alternative amendments that are ultimately taken forward
CAP166 WGCR-03	National Grid Electricity Transmission	An Alternative whereby the baseline capacity auctioned is equivalent to the existing physical network capacity only with the proviso that no reserve price would be set. This request would apply across each of the original and any alternative amendments that are ultimately taken forward
CAP166 WGCR-04	Welsh Power	An Alternative whereby the principles put forward by WGAA1 would be largely retained with the caveat that when the incremental capacity release supply function is calculated it should be unconstrained after 5 years.

13.2 Views of Panel Members

13.2.1 TBC following Panel vote.

13.3 Views of Core Industry Document Owners

13.3.1 None received.

14.0 VIEWS INVITED

14.1 National Grid is seeking the views of interested parties in relation to the issues raised by Amendment Proposal CAP166 and issues arising from the proposed timescale for implementation of CAP166

14.2 Please send your responses to this consultation to National Grid (bali.virk@uk.ngrid.com) by no later than close of business on **23rd February 2009**

ANNEX 1 – WORKING GROUP ISSUES LIST

The following list of issues summarises the Working Group's view of the areas it needed to fully develop to enable industry participants and the Authority to robustly consider the proposals put forward by CAP166.

The Working Group felt that it was unable to consider all of the issues fully in time for this Working Group consultation, and so the list of issues that follows is colour-coded:

- Red Text denotes issues that the Working Group feels it has considered fully and its views are set out in this Working Group Consultation
- Blue text denotes issues that the Working Group believes it will be able to fully consider prior to issuing to the CUSC Panel its Final Working Group Report
- Green Text denotes issues that will be taking forward under a separate Charging Consultation
- Black text denotes issues that will be considered in any Implementation plan should the Authority ultimately approve CAP166 or any of its Alternatives

Issues List

- Definition
  - Process for, and timing of, long-term auctions (set out in section 4.3), including detailed business rules (to be left until any implementation process)
    - Flow chart, for existing post-commissioning, existing precommissioning and new precommissioning (included as an Annex 2 to the Working Group report)
  - Interaction of local and wider
    - Application / qualification process and required agreements (Section 4.3)
    - Security (Section 3.5)
    - Timing and frequency of auctions (3.4 and 4.3)
  - Embedded generation (generically set out that all Embedded generators that currently have a TEC will be subject to the auction process to retain wider access rights)
  - Reallocation mechanism – resolving under- and over-recoveries (via a separate charging pre-consultation)
  - Financial or physical right? (section 4.7)
  - Compensation rights – buyback rules, scaling and issues with late delivery, also CAP048 type issues (section 4.7)
  - Baseline capacity (fundamentals set out in the report, however exact baseline capacities not yet calculated)
  - Methodology statements, including substitutability
  - Information flows (Set out in section 3.4 & Annex 2 – Flow Chart)
  - How many constraint boundaries are required?
  - Example Constraint boundaries and commentary around them (included as Annex 3)
  - Bid evaluation process (section 4.5)
  - Auction duration and rounds (initial proposals included in section 4.3, yet to be confirmed)
  - Closure rules
  - Ancillary services (section 4.8)
  - Treatment of unsold capacity (section 4.5)
  - Transition and implementation
  - Auction governance

- Testing (benefits)
  - Developing excel model – one year, single round initially – add under- and over-recovery (section 4.5)
  - trade off between allocation of rights and ability of parties to play the game (transparency / intuitive signals)
  - Beta Model for wider industry testing (Feb 2009)
  - What is being optimised? Capacity release or auction revenue or economic release of incremental capacity (section 4.5)
  - Impact of reserve prices (collar in importing zones only – section 4.5) follow up in subsequent charging pre-consultation
  - Build more representative model (Beta model)
    - Test normally
    - Multiple years
    - Test impact on types of parties
    - Portfolio impacts
  - Does price give players useful information?
  - Test original zonal model (no longer required as original no longer preferred model)
    - How much does outcome depend on initial allocation of baseline zonal capacity?
  - Test against current process
  - Specification of central and interface systems (Feb. 2009)
  - In importing zones how do we reflect parties participating in the short-term? (section 4.5)

- IS Specification (Costs)
  - Web interface?
  - Cost of central systems and for Users

- SO/TO incentives
  - Identify issues to be taken forward

ANNEX 2 – HIGH LEVEL PROCESS FLOW-CHART

The following flowchart was developed by the Working Group to assist in its understanding of the end-to-end process

ANNEX 3 – INITIAL ANALYSIS OF AUCTION BOUNDARIES

The attached map records the results of National Grid's initial indicative analysis of the auction boundaries to be utilised in a Year 1 auction.

There are a large number of boundaries initially to manage the transition from existing arrangements to a new auction based method of allocating capacity. In subsequent years it is anticipated that these boundaries might become inactive and increasingly fewer of them will play an active part in the auction process.

Also attached is a look up table to help respondents to the consultation identify which zones interact with each other.

Competing Boundaries Look-up table

Scotland

Generation in	Competing boundaries
SC1	SC1, B1, B4, B5, B6, B7, FIDFN, FIDFS, B8, B9
SC2	SC2, B1, B4, B5, B6, B7, FIDFN, FIDFS, B8, B9
SC3*	SC3, B4, B5, B6, B7, FIDFN, FIDFS, B8, B9
SC4	SC4, B4, B5, B6, B7, FIDFN, FIDFS, B8, B9
SC5	SC5, B6, B7, FIDFN, FIDFS, B8, B9,
B1	B1, B4, B5, B6, B7, FIDFN, FIDFS, B8, B9,
B3	B3, B4, B5, B6, B7, FIDFN, FIDFS, B8, B9,
B4	B4, B5, B6, B7, FIDFN, FIDFS, B8, B9,
B5	B5, B6, B7, FIDFN, FIDFS, B8, B9,
B6	B6, B7, FIDFN, FIDFS, B8, B9,

* subject to further study

North East and Humber

Generation in	Competing boundaries
NE1	NE1, NE2, NE0, NH0, B7, FIDFN, FIDFS, B8, B9,
NE2	NE2, NE0, NH0, B7, FIDFN, FIDFS, B8, B9,
NE5	NE5, NE6, NE0, NH0, B7, FIDFN, FIDFS, B8, B9,
NE6	NE6, NE0, NH0, B7, FIDFN, FIDFS, B8, B9,
NE0	NE0, NH0, B7, FIDFN, FIDFS, B8, B9,
HU1	HU1, HU3, HU0, NH0, FIDFS, B8, B9,
HU2	HU2, HU3, HU0, NH0, FIDFS, B8, B9,
HU3	HU3, HU0, NH0, FIDFS, B8, B9,
HU4	HU4, HU0, NH0, FIDFS, B8, B9,
HU6	HU6, HU7, HU0, NH0, FIDFS, B8, B9,
HU7	HU7, HU0, NH0, FIDFS, B8, B9,
HU0	HU0, NH0, FIDFS, B8, B9,
NH0	NH0, B7, FIDFN, FIDFS, B8, B9,

North West and Yorkshire

Generation in	Competing boundaries
NW1	NW1, NW0, FIDFN, FIDFS, B8,B9,
NW0	NW0, B7, FIDFN, FIDFS, B8,B9,
NW9	NW9, B7, FIDFN, FIDFS, B8,B9,
NW2	NW2, NW3, FIDFS, B8, B9,
NW3	NW3, FIDFS, B8, B9,
NW4	NW4, NW6, NW7, B8, B9,
NW5	NW5, NW6, NW7, B8, B9,
NW6	NW6, NW7, B8, B9,
NW7	NW7, B8, B9,
YK1	YK1, YK0, FIDFS, B8, B9,
YK0	YK0, FIDFS, B8, B9,

Midlands and East Anglia

Generation in	Competing boundaries
B17	B17, B9,
MID1	MID1, B9,
EA1	EA1, EA0
EA2	EA2, EA0
EA3	EA3, EA2, EA0
EA4	EA4, EA0
EA5	EA5, EA0

South Wales and Home Counties

Generation in	Competing boundaries
SW1	SW1, SW3, SW0
SW2	SW2, SW3, SW0
SW3	SW3, SW0
SW0	SW0
HC1	HC1, HC0
HC2	HC2, HC0

London and Thames Estuary

Generation in	Competing boundaries
B14	B14
B15 (TH0)*	TH0

* Thames Estuary analysis remains to be completed

South West and South Coast

Generation in	Competing boundaries
B13	B13
SE1	SE1, SE2
SE2	SE2

ANNEX 4 – MATRIX OF CAP166 WORKING GROUP DEVELOPMENTS OF CONSULTATION REQUESTS AND WGAAs

Reference	Company	Details of the proposal	Adopted as formal WGAA?
CAP166 WGCR-01	National Grid Electricity Transmission	An Alternative based upon WGAA1 as set out in the report, but with the exception that the auctions are settled according to a Pay as Bid principle and not through a cleared price	NO
CAP166 WGCR-02	National Grid Electricity Transmission	An Alternative whereby the baseline capacity released through the auction is greater than that which currently physically exists on the GB Transmission System, and where a locational reserve price is set in the auction to prevent this over-allocation of capacity allowing the auction prices to collapse towards £0/kW. This request would apply across each of the original and any alternative amendments that are ultimately taken forward	YES (WGAA2)
CAP166 WGCR-03	National Grid Electricity Transmission	An Alternative whereby the baseline capacity auctioned is equivalent to the existing physical network capacity only with the proviso that no reserve price would be set. This request would apply across each of the original and any alternative amendments that are ultimately taken forward	NO
CAP166 WGCR-04	Welsh Power	An Alternative whereby the principles put forward by WGAA1 would be largely retained with the caveat that when the incremental capacity release supply function is calculated it should be unconstrained after 4 years.	NO

ANNEX 5 – WORKING GROUP TERMS OF REFERENCE AND MEMBERSHIP

Working Group Terms of Reference and Membership

TERMS OF REFERENCE FOR CAP165-166 WORKING GROUP 'ACCESS WORKING GROUP 2'

RESPONSIBILITIES

1. The Working Group is responsible for assisting the CUSC Amendments Panel in the evaluation of CUSC Amendment Proposals CAP165 and CAP166 tabled by National Grid at the Amendments Panel meeting on 25th April 2008.

2. The proposals must be evaluated to consider whether each of them better facilitates achievement of the applicable CUSC objectives. These can be summarised as follows:

   (a) the efficient discharge by the Licensee of the obligations imposed on it by the Act and the Transmission 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.

3. It should be noted that additional provisions apply where it is proposed to modify the CUSC amendment provisions, and generally reference should be made to the Transmission Licence for the full definition of the term.

SCOPE OF WORK

4. The Working Group must consider the issues raised by the Amendment Proposals and consider if each of the proposals identified better facilitates achievement of the Applicable CUSC Objectives.

5. In addition to the overriding requirement of paragraph 4, the Working Group shall consider and report on the following specific issues for both CAP165 and CAP166:

   - Impact on bilateral agreements (BCA, BEGAs, CONSAG, Offers etc.)
   - Impact on computing systems, central and individual CUSC party
   - Efficiency of investment signals (for generation, transmission and interconnectors)
   - Effect on competition
   - Applicability to embedded generation
   - Impact on industry documents, including SQSS
   - Definitions, including interaction with other codes and methodologies
   - Interaction with proposed Offshore regime
   - A cost benefit analysis, including:
     - Consideration of the cost of carbon
     - Impact on all classifications of users
     - Impact on system operator and transmission owners
   - Impact on maintenance of the reliability, safety and operation of the grid
   - Impact on Security of Supply
   - Ability of CUSC Parties to trade access rights (short and long term) between themselves

5.a For CAP165, the Working Group shall also consider and report on the following specific issues:

- Nature and definition of rights (including whether zonal rights are recorded zonally or nodally)
- Impact on / transition for users with existing rights
- Application process for extension of rights
- Efficient use of capacity and relinquishment / reduction of rights
- Minimum / maximum booking period
- Definition of an appropriate level of financial security
- Consideration of user commitment in negative charging zones
- Equitable treatment of new and existing users
- Calculation of the trigger period for incremental capacity bookings
- Consideration of the appropriate level of user commitment for new users
- The profile of financial security required pre-commissioning
- Interaction with security requirements for local infrastructure
- Transition and retrospective application for new users

5.b For CAP166, the Working Group shall also consider and report on the following specific issues:

- Type of auction
- Process for, and timing of, long-term auctions (including detailed business rules)
- Size and period of capacity block
- Specification of product (including financial or physical in nature, and rights to compensation)
- Period of release, including interaction with re-zoning
- Evaluation of bids for different numbers of years
- Is there the need for a reserve price?
- Consideration of negative reserve prices (if any) and bids
- Long-term Auction restrictions (e.g. would participation eligibility be restricted to those with a local connection or offer for such?)
- Definition of baselines, and governance of baseline definition
- Definition of an appropriate level of financial security
- Impact on users with existing rights
- Treatment of unsold capacity and incremental capacity
- Definition of regulatory test for release of incremental capacity
- Governance of regulatory test for release of incremental capacity
- Definition of release period for incremental capacity
- Application process for new connections
- Transition, including existing commitments for reinforcements
- Implementation - processes and systems required
- Consideration of relevant parallels from the gas experience

5.c This working group shall have a sub group, the CAP161-166 Enabling Sub-group. The Terms of Reference for this sub-group shall be agreed by the Amendments Panel and shall include the consideration of a number of enabling changes, principally:

- Zonal definition of wider transmission access rights
- Zoning criteria and methodology governance
- Definition of local access (intra-zonal access rights)
- Local only applications
- Local access charging and financial security requirements
- Residual charging and credit requirements

6. The Working Group is responsible for the formulation and evaluation of any Working Group Alternative Amendments (WGAAs) arising from Group discussions which would, as compared with the Amendment Proposals, better facilitate achieving the applicable CUSC objectives in relation to the issue or defect identified.

7. The Working Group should become conversant with the definition of Working Group Alternative Amendments which appears in Section 11 (Interpretation and Definitions) of the CUSC. The definition entitles the Group and/or an individual Member of the Working Group to put forward a Working Group Alternative Amendment if the Member(s) genuinely believes the Alternative would better facilitate the achievement of the Applicable CUSC Objectives. The extent of the support for the Amendment Proposals or any Working Group Alternative Amendments arising from the Working Group's discussions should be clearly described in the final Working Group Report to the CUSC Amendments Panel.

8. There is an obligation on the Working Group Members to propose the minimum number of Working Group Alternatives where possible.

9. All proposed Working Group Alternatives should include the proposer(s) details within the Final Working Group Report, for the avoidance of doubt this includes Alternative(s) which are proposed by the entire Working Group or subset of members.

10. There is an obligation on the Working Group to undertake a period of Consultation in accordance with CUSC 8.17. The Working Group Consultation period shall be for a period of 4 weeks as determined by the Amendment Panel.

11. Following the Consultation period the Working Group is required to consider all responses including any WG Consultation requests. As appropriate the Working Group will be required to undertake any further analysis and update the Original and/or Working Group Alternatives. All responses including any WG Consultation Requests shall be included within the final report including a summary of the working Groups deliberations and conclusions.

12. The Working Group is to submit their final report to the CUSC Panel Secretary on 17th July 2008 for circulation to Panel Members. The conclusions will be presented to the CUSC Panel meeting on 25th July 2008.

MEMBERSHIP

13. It is recommended that the Working Group has the following members:

Chair	Hêdd Roberts
National Grid	Andrew Truswell
Industry Representatives	James Anderson
	Graeme Cooper
	Stuart Cotten
	Sebastian Eyre
	Nick Frydas
	Garth Graham
	Paul Jones
	Simon Lord
	Cathy McClay
	Fiona Navesey

	Bill Reed
	Ed Reed
	Helen Snodin
	Lisa Waters
	Barbara Vest
Authority Representative	Min Zhu / David Hunt
Technical Secretary	Sarah Hall

NB: Working Group must comprise at least 5 Members (who may be Panel Members)

14. The Chair of the Working Group and the Chair of the CUSC Panel must agree a number that will be quorum for each Working Group meeting. The agreed figure for CAP165 and CAP166 is that at least 5 Working Group members must participate in a meeting for quorum to be met.

15. A vote is to take place by all eligible Working Group members (for the avoidance of doubt, that is (i) the Proposer (National Grid) and (ii) the Industry representatives listed above) on the proposal and each Working Group Alternative, as appropriate, as to whether it better facilitates the CUSC Applicable Objectives and indicate which option is considered the BEST with regard to the CUSC Applicable Objectives. The results from the vote shall be recorded in the Working Group Report.

16. Working Group Members or their appointed alternate is required to attend a minimum of 50% of the Working Group Meetings to be eligible to participate in the Working Group vote.

17. The Technical Secretary to keep an Attendance Record, for the Working Group meetings and to circulate the Attendance Record with the Action Notes after each meeting. This will be attached to the Final Working Report.

18. The membership can be amended from time to time by the CUSC Amendments Panel.

19. If any Working Group Member wishes to nominate an Alternate (to act on their behalf in their absence from meetings) then this should be sent to the Working Group Chair once the Working Group is under way who will confirm (to the Working Group Member) that the Alternate is duly designated. For the avoidance of doubt if the Working Group Chair believes the suggested Alternate does not have sufficient expertise in the issues being considered by the Working Group they will ask the Working Group Member to suggest a more suitable Alternate.

20. Observers may be permitted by the Chair to attend any meeting. It should be noted that the observer (i) will not have a vote and (ii) cannot speak unless asked to do so by the Chair. Any CUSC Party wishing to be an observer should agree with the Working Group Chair advance .The Chair may invite additional industry experts to any meeting as required to ensure efficient and comprehensive coverage of the agenda.

RELATIONSHIP WITH AMENDMENTS PANEL

21. The Working Group shall seek the views of the Amendments Panel before taking on any significant amount of work. In this event the Working Group Chairman should contact the CUSC Panel Secretary.

22. The Working Group shall seek the Amendments Panel advice if a significant issue is raised during the Consultation process which would require a second period of Consultation in accordance with 8.17.17.

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

24. The working group shall maintain a register of assumptions and issues, which is to be reported to the Amendments Panel and other Transmission Access working groups on a regular basis.

MEETINGS

25. The Working Group shall, unless determined otherwise by the Amendments Panel, develop and adopt its own internal working procedures and provide a copy to the Panel Secretary for each of its Amendment Proposals.

26. To ensure an efficient process (and mindful of room logistics) only the Working Group Member or their appointed Alternate can attend a meeting. If an alternate wishes to attend the same meeting as their associated member this will be as an observer (under item 18. above) unless they have previously agreed with the Working Group Chair.

REPORTING

27. The Working Group Chair shall prepare a final report to the 25th July 2008 Amendments Panel responding to the matter set out in the Terms of Reference.

28. A draft Working Group report will be produced individually for each of CAP165 and CAP166. Each draft working group report will include the relevant information from the CAP161-166 Enabling Sub-group.

29. A draft Working Group Report must be circulated to Working Group members with not less than five business days given for comments.

30. Any unresolved comments within the Working Group must be reflected in the final Working Group Report.

31. The Working Group Chair (or another Working Group member nominated by him) will present the Working Group report to the Amendments Panel as required.

ANNEX 6 – WORKING GROUP ATTENDANCE REGISTER

		1	2	3	4	5	6	7	8	9	10	11	12
Name	Company	14/05/2008	29/05/2008	11/06/2008	24/06/2008	09/07/2008	28/07/2008	07/08/2008	21/08/2008	04/09/2008	11/09/2008	23/09/2008	02/10/2008
Working Group Members													
Hêdd Roberts	National Grid	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Andrew Truswell	National Grid	✓	✓	✓	✓	✓	✓	✓	✓	✓	×	✓	✓
Sarah Hall	National Grid	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
James Anderson	Scottish Power	✓	✓	✓	✓	Gerry Hoggan	✓	✓	✓	✓	✓	✓	✓
Stuart Cotten	Drax Power	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Sebastian Eyre	EDF Energy	✓	×	✓	Stefan Leedham	✓	Emma Luckhurst	✓	✓	Emma Luckhurst	Stefan Leedham	✓	×
Nick Frydas	Merrill Lynch	✓	×	×	✓	✓	✓	×	✓	×	✓	×	×
Garth Graham	SSE	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Paul Jones	E.ON UK	✓	✓	✓	✓	✓	✓	✓	✓	×	✓	×	✓
Simon Lord	First Hydro	✓	Kevin Dibble	Kevin Dibble	✓	✓	✓	✓	Kevin Dibble	✓	✓	✓	✓
Cathy McClay	British Energy	✓	✓	✓	✓	✓	Louise Schmitz	✓	Rob Rome	Louise Schmitz	Louise Schmitz	✓	✓
Fiona Navesey	Centrica	✓	Dave Wilkerson	✓	Dave Wilkerson	✓	✓	Dave Wilkerson	✓	✓	✓	✓	✓
Bill Reed	RWE npower	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Edward Reed	Cornwall Energy Associates	✓	✓	Bob Brown	✓	Bob Brown	×	✓	×	✓	×	×	✓
Helen Snodin	Xero Energy	✓	Nigel Scott	✓	✓	✓	✓	✓	✓	✓	✓	✓	×
Lisa Waters	Welsh Power	✓	✓	✓	×	✓	✓	✓	✓	✓	✓	✓	✓
Barbara Vest	AEP	✓	Dennis Gowland	Dennis Gowland	Dennis Gowland	✓	✓	✓	✓	✓	×	✓	Dennis Gowland
Min Zhu	Ofgem	✓	✓	✓	Stuart Cook	✓	✓	David Hunt	✓	✓	✓	✓	✓
Alternatives and Observers													
Peter Bolitho	E.ON UK	×	×	×	✓	×	×	×	×	×	×	×	×
Bob Brown	Cornwall Energy Associates	×	×	✓	×	✓	×	×	×	×	×	×	×
Stuart Cook	Ofgem	×	×	×	✓	✓	✓	×	×	×	×	×	×
Kevin Dibble	First Hydro	×	✓	✓	×	×	×	×	✓	×	×	×	×
Steve Fisher	National Grid	×	×	×	✓	✓	×	×	×	×	×	×	×
Dennis Gowland	Fairwind (Orkney) Ltd	×	✓	✓	✓	×	✓	✓	✓	✓	✓	×	✓
Jerrald Hauber	RWE Innogy	✓	✓	×	✓	✓	✓	×	✓	✓	✓	×	×
Gerry Hoggan	Scottish Power	×	×	×	×	✓	×	×	×	×	×	×	×
Stefan Leedham	EDF Energy	×	×	×	✓	✓	×	✓	×	×	✓	×	×
Emma Luckhurst	EDF Energy	×	×	✓	×	×	✓	×	×	✓	×	×	×
Nigel Scott	Xero Energy	×	✓	×	×	×	×	×	×	×	×	×	×
Dave Wilkerson	Centrica	×	✓	×	✓	×	×	✓	×	×	×	×	✓
Mike Young	Centrica	×	×	×	✓	×	×	×	×	×	×	×	×
Louise Schmitz	British Energy	×	×	×	×	×	✓	×	×	×	✓	×	×
Tony Dicicco	RWE npower	×	×	×	×	×	×	✓	×	×	×	×	×
David Hunt	Ofgem	×	×	×	×	×	×	✓	×	×	×	×	×
Chris Stewart	Centrica	×	×	×	×	×	×	✓	×	×	×	×	×
Phil Hicken	BERR	×	×	×	×	×	×	✓	×	×	×	×	×
Rob Rome	British Energy	×	×	×	×	×	×	×	✓	×	×	×	×
ian lomas	BERR	×	×	×	×	×	×	×	×	×	✓	×	×
Mark Duffield	National Grid	×	×	×	×	×	×	×	×	×	×	×	×
Angela Quinn	National Grid	×	×	×	×	×	×	×	×	×	×	×	×
Elaine Calvert	National Grid	×	×	×	×	×	×	×	×	×	×	×	×
Merel Van der Neut Kolfshoten	Centrica	×	×	×	×	×	×	×	×	×	×	×	×
David Scott	EDF Energy	×	×	×	×	×	×	×	×	×	×	×	×
Laura McVean	SSE	×	×	×	×	×	×	×	×	×	×	×	×
Stephen Barnett	National Grid	×	×	×	×	×	×	×	×	×	×	×	×

		13	14	15	16	17	18	19	20	21	22	23
Name	Company	06/10/2008	08/10/2008	10/10/2008	15/10/2008	16/10/2008	24/10/2008	04/11/2008	11/11/2008	18/11/2008	19/11/2008	27/11/2008
Working Group Members												
Hêdd Roberts	National Grid	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Andrew Truswell	National Grid	✓	Mark Duffield	Mark Duffield	Mark Duffield	Mark Duffield	Mark Duffield	Mark Duffield	Mark Duffield	Mark Duffield	Mark Duffield	Mark Duffield
Sarah Hall	National Grid	✓	✓	✓	×	×	✓	✓	✓	✓	✓	✓
James Anderson	Scottish Power	✓	×	×	×	×	✓	✓	✓	✓	✓	✓
Stuart Cotten	Drax Power	✓	✓	×	✓	✓	✓	×	×	✓	✓	×
Sebastian Eyre	EDF Energy	✓	×	Emma Luckhurst	David Scott	David Scott	×	×	×	×	×	×
Nick Frydas	Merrill Lynch	×	×	×	×	×	×	×	×	×	×	×
Garth Graham	SSE	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Paul Jones	E.ON UK	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Simon Lord	First Hydro	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Cathy McClay	British Energy	✓	✓	✓	✓	✓	×	✓	✓	✓	✓	Rob Rome
Fiona Navesey	Centrica	✓	✓	×	Merel Kolfshoten	×	×	×	Merel Kolfshoten	✓	Merel Kolfshoten	×
Bill Reed	RWE npower	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Edward Reed	Cornwall Energy Associates	×	×	×	×	×	×	×	Bob Brown	Bob Brown	Bob Brown	×
Helen Snodin	Xero Energy	×	×	×	×	×	×	✓	✓	✓	✓	✓
Lisa Waters	Welsh Power	✓	×	×	×	×	×	×	✓	✓	✓	✓
Barbara Vest	AEP	✓	✓	×	×	×	Dennis Gowland	Dennis Gowland	Dennis Gowland	Dennis Gowland	Dennis Gowland	Dennis Gowland
Min Zhu	Ofgem	✓	✓	×	✓	✓	David Hunt	×	✓	✓	✓	✓
Mike Davies	Wind Energy	×	×	×	×	×	×	×	×	×	×	×
Alternatives and Observers												
Peter Bolitho	E.ON UK	×	×	×	×	×	×	×	×	×	×	×
Bob Brown	Cornwall Energy Associates	×	×	×	×	×	×	×	✓	✓	✓	×
Stuart Cook	Ofgem	✓	×	×	×	×	×	×	×	×	×	×
Kevin Dibble	First Hydro	×	×	×	×	×	×	×	×	×	×	×
Steve Fisher	National Grid	×	×	×	×	×	×	×	×	×	×	×
Dennis Gowland	Fairwind (Orkney) Ltd	✓	×	×	×	×	✓	✓	✓	✓	✓	✓
Jerrald Hauber	RWE Innogy	×	✓	✓	×	×	✓	✓	×	✓	×	✓
Gerry Hoggan	Scottish Power	×	×	×	×	×	×	×	×	×	×	×
Stefan Leedham	EDF Energy	×	×	×	×	×	×	×	×	×	×	×
Emma Luckhurst	EDF Energy	×	×	✓	✓	✓	×	×	×	×	×	×
Nigel Scott	Xero Energy	×	×	×	×	×	×	×	×	×	×	×
Dave Wilkerson	Centrica	×	×	×	×	×	×	×	×	×	×	×
Mike Young	Centrica	×	×	×	×	×	×	×	×	×	×	×
Louise Schmitz	British Energy	×	×	×	×	×	×	×	×	×	×	×
Tony Dicicco	RWE npower	×	×	×	×	×	×	×	×	×	×	×
David Hunt	Ofgem	×	×	×	×	×	✓	×	×	×	×	×
Chris Stewart	Centrica	×	×	×	×	×	×	×	×	×	×	×
Phil Hicken	BERR	×	×	×	×	×	×	×	×	×	×	×
Rob Rome	British Energy	×	✓	✓	×	×	×	×	×	×	✓	✓
ian lomas	BERR	×	×	×	×	×	×	×	×	×	×	×
Mark Duffield	National Grid	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Angela Quinn	National Grid	✓	×	✓	×	×	✓	✓	×	×	×	×
Elaine Calvert	National Grid	×	×	✓	×	×	×	×	×	×	×	✓
Merel Van der Neut Kolfshoten	Centrica	×	×	×	✓	×	×	×	✓	×	✓	×
David Scott	EDF Energy	×	×	×	✓	✓	×	×	×	×	×	×
Laura McVean	SSE	×	×	×	×	×	×	×	×	×	×	×
Stephen Barnett	National Grid	×	×	×	×	×	×	×	×	×	✓	✓
Micheal Dodd	ESBI	×	×	×	×	×	×	×	×	×	×	×
John Morris	British Energy	×	×	×	×	×	×	×	×	×	×	×
Robert Longden	Scottish Renewables Forum	×	×	×	×	×	×	×	×	×	×	×
Colin Mochan	SSE	×	×	×	×	×	×	×	×	×	×	×

		24	25	26	27	28	29	30
Name	Company	02/12/2008	10/12/2008	15/12/2008	09/01/2009	15/01/2009	21/01/2009	27/01/2009
Working Group Members								
Hêdd Roberts	National Grid	✓	✓	✓	✓	✓	✓	✓
Andrew Truswell	National Grid	Mark Duffield	Mark Duffield	Mark Duffield	Mark Duffield	Mark Duffield	Mark Duffield	Mark Duffield
Sarah Hall	National Grid	✓	✓	✓	✓	✓	✓	✓
James Anderson	Scottish Power	✓	✓	×	✓	✓	✓	✓
Stuart Cotten	Drax Power	✓	✓	✓	✓	✓	×	✓
Sebastian Eyre	EDF Energy	×	×	×	×	×	×	✓
Nick Frydas	Merrill Lynch	×	×	×	×	×	×	×
Garth Graham	SSE	✓	✓	✓	✓	✓	✓	✓
Paul Jones	E.ON UK	✓	✓	×	✓	✓	✓	✓
Simon Lord	First Hydro	✓	×	✓	✓	×	✓	✓
Cathy McClay	British Energy	Rob Rome	Louise Schmitz	Louise Schmitz	John Morris	John Morris	Louise Schmitz	Louise Schmitz
Fiona Navesey	Centrica	✓	✓	✓	✓	✓	Merel Kolfshoten	Merel Kolfshoten
Bill Reed	RWE npower	✓	✓	✓	✓	✓	✓	✓
Edward Reed	Cornwall Energy Associates	×	×	Bob Brown	Bob Brown	Bob Brown	×	×
Helen Snodin	Xero Energy	✓	×	✓	✓	✓	✓	
Lisa Waters	Welsh Power	×	×	×	✓	✓	✓	✓
Barbara Vest	AEP	Dennis Gowland	×	×	Dennis Gowland	Dennis Gowland	✓	×
Min Zhu	Ofgem	✓	✓	David Hunt	✓	✓	✓	✓
Mike Davies	Wind Energy	×	✓	✓	✓	×	×	✓
Alternatives and Observers								
Peter Bolitho	E.ON UK	×	×	×	×	×	×	×
Bob Brown	Cornwall Energy Associates	×	×	✓	✓	✓	×	×
Stuart Cook	Ofgem	✓	×	×	✓	✓	✓	×
Kevin Dibble	First Hydro	×	×	×	×	×	×	×
Steve Fisher	National Grid	×	×	×	×	×	×	×
Dennis Gowland	Fairwind (Orkney) Ltd	✓	×	×	✓	✓	×	×
Jerrald Hauber	RWE Innogy	×	✓	×	×	✓	✓	✓
Gerry Hoggan	Scottish Power	×	×	×	×	×	×	×
Stefan Leedham	EDF Energy	×	×	×	×	×	×	×
Emma Luckhurst	EDF Energy	×	×	×	×	×	×	×
Nigel Scott	Xero Energy	×	×	×	×	×	×	×
Dave Wilkerson	Centrica	×	×	×	×	×	×	×
Mike Young	Centrica	×	×	×	×	×	×	×
Louise Schmitz	British Energy	×	✓	✓	×	×	✓	✓
Tony Dicicco	RWE npower	×	×	×	×	×	×	×
David Hunt	Ofgem	×	×	✓	×	×	×	×
Chris Stewart	Centrica	×	×	×	×	×	×	×
Phil Hicken	BERR	×	×	×	×	×	×	×
Rob Rome	British Energy	✓	×	×	×	×	×	×
Ian Lomas	BERR	×	×	×	×	×	×	×
Mark Duffield	National Grid	✓	✓	✓	✓	✓	✓	✓
Angela Quinn	National Grid	×	×	×	×	×	×	×
Elaine Calvert	National Grid	✓	✓	✓	✓	✓	✓	✓
Merel Van der Neut Kolfshoten	Centrica	×	×	×	×	×	✓	✓
David Scott	EDF Energy	×	×	×	×	×	×	×
Laura McVean	SSE	×	×	×	×	×	×	×
Stephen Barnett	National Grid	✓	×	×	×	×	✓	×
Micheal Dodd	ESBI	×	×	✓	✓	✓	×	✓
John Morris	British Energy	×	×	×	✓	✓	×	×
Robert Longden	Scottish Renewables Forum	×	×	×	×	×	×	✓
Colin Mochan	SSE	×	×	×	×	×	×	✓

Working Group 3

Date	12-May	27-May	04-Jun	16-Jun	29-Jun	13-Jul	29-Jul	13-Aug	22-Aug	02-Sep	12-Sep	25-Sep	10-Nov
Meeting No.	1	2	3	4	5	6	7	8	9	10	11	12	13
Allan Kelly	1	1	1	1	1	1		1	1				
Anthony Mungall	1	1		1		1		1			1		1
Barbara Vest	1				1	1	1	1			1	1	
Craig Maloney	1	1	1	1	1	1	1	1	1		1	1	1
Dave Wilkerson	1	1	1	1	1	1	1				1	1	1
Dennis Timmins	1		1	1	1	1	1		1		1	1	1
Frank Prashad	1		1	1	1	1	1	1	1		1	1	
Hêdd Roberts	1	1	1	1	1	1	1	1	1		1	1	1
Louise Schmitz	1	1	1	1	1	1	1	1	1		1	1	1
Helen Snodin (N Scott)	1	1	1	1	1	1	1	1	1		1	1	1
Paul Jones	1	1	1	1	1		1	1	1		1		1
Robert Longden	1	1		1		1	1	1	1		1		1
Simon Lord	1			1	1	1	1				1	1	1
David Lewis	1												
Bee Hun Tan				1	1	1	1	1	1		1	1	
Tom Ireland	1	1	1	1	1	1	1	1	1	Cancelled	1		1
Chris Barrass	1	1		1		1	1						
Qiong Zhou (Jo)	1	1		1	1	1	1	1	1		1	1	
Brian Taylor		1											
Michael Dodd			1		1		1		1			1	
Sebastian Eyre			1			1							
Emma Luckhurst			1		1	1	1				1	1	
Andrew Rimmer			1										
Dan Jerwood			1										
Stefan Leedham				1									
Stephen Curtis				1	1		1	1			1	1	1
Garth Graham					1								
Owen Wilkes					1								
David Walker						1							
Stuart Cotten						1	1	1					
James Anderson							1					1	
Stuart Cook						1					1		
David Scott													1

ANNEX 7 – AMENDMENT PROPOSAL FORM

CUSC Amendment Proposal Form	CAP:166

Title of Amendment Proposal:

Transmission Access – Long-term Entry Capacity Auctions

Description of the Proposed Amendment *(mandatory by proposer)***:**

It is proposed that all long-term entry access rights to the GB transmission system would be allocated by auction. Available access rights would be identified on a zonal basis, and released in annual (financial year) blocks. Auctions would be held annually, and capacity allocated on a pay as bid basis to the limit of the available ("baseline") zonal capability. Successful bookings would be underpinned by User commitment in the form of a liability to pay the accepted bids and a consequential requirement for financial security to be put in place. This will be developed during the assessment of the proposed amendment, in accordance with the Best Practice Guidelines for Gas and Electricity Network Operator Credit Cover.

Outside of a specified period, incremental capacity would be released by the System Operator where any unfulfilled bids in excess of the zonal reserve price were of a level sufficient to pass a regulatory test, which would be defined under a separate Incremental Entry Capacity Release (IECR) methodology.

The above arrangements would provide access to the wider transmission system. Separate arrangements would be put in place for infrastructure comprising generators' local connections to the wider system, such that potential new generators could first apply for a local connection, and then have their offer held open until the next auction for wider system capacity had concluded. It is envisaged that generators' bids for long-term entry access rights would be constrained to the sum of their prevailing contracted or offered local capacity limits in each zone. Separate arrangements for charging and security would apply for local infrastructure, and for the residual element of the entry Transmission Network Use of System (TNUoS) capacity charge, which it is proposed would be levied on a commoditised basis.

Description of Issue or Defect that Proposed Amendment seeks to Address *(mandatory by proposer)***:**

The current entry access arrangements give existing generators a rolling option to renew their rights to access the transmission system on an annual basis. The allocation of these rights is through incumbency, so that, in the constrained period (before incremental capacity can be provided), new Users have no ability to gain from the System Operator long-term access rights even if they would value them more highly than incumbents. The fact that the true value of transmission access rights cannot be discovered from the market compromises transmission licensees' ability to develop an optimally economical system of electricity transmission, as well as creating a barrier to entry. Entry could be facilitated by improving liquidity in the trading of access rights (and separate amendments are being proposed to do so), but in order for Users that are able to trade capacity to do so at value they first should have had to pay value for those rights.

The proposed amendment also seeks to address the issue that the current arrangements, whereby generators have a rolling option, do not provide any certainty to National Grid and Transmission Owners. This uncertainty can lead to inefficient investment signals, in that the planning of incremental capacity currently can take little, if any, account of the potential future release of existing capacity currently held by incumbents. Additionally, existing generators are not required to put in place any financial security, even for the one year's worth of charges they currently incur a liability for.

National Grid believes that both of the above issues would be addressed through the introduction of auctions for long-term entry capacity rights. The allocation of such rights through auctions would ensure that rights were released at value, thereby facilitating the economical development of the transmission system, and reducing barriers to entry by allowing the release of capacity to those that value it most highly. The long-term booking of capacity, with associated User commitment, would also provide more efficient investment signals, thereby reducing the risk of stranding, and would facilitate the release of existing capacity to new entrants.

Impact on the CUSC *(this should be given where possible)*:

The impact on the CUSC would include, but may not be limited to, changes to Sections 2 (Connection), 3 (Use of System), 6 (General Provisions) and 9 (Interconnectors). There would also be consequential changes required to Sections 11 (Interpretation and Definitions), and potentially to the CUSC Schedules and Exhibits.

Impact on Core Industry Documentation *(this should be given where possible)*:

No impact on Core Industry Documentation has been identified, but it is suggested that this would be reviewed during the assessment of the proposed amendment.

Impact on Computer Systems and Processes used by CUSC Parties *(this should be given where possible)*:

New processes, and potentially computer systems, would be required to participate in the auction process.

CUSC Parties' models of the financial viability of new and existing power stations and interconnectors would need to take into account the revised arrangements.

Details of any Related Modifications to Other Industry Codes *(where known)*:

Related modifications to the Use of System Charging Methodology would be proposed to set zonal reserve prices for the capacity auctions. It is envisaged that these would be based on the wider locational element of the current entry (generation) TNUoS charge.

Additional modifications to the Use of System Charging Methodology would be proposed to cost reflectively charge local infrastructure (and to therefore separate this from the auctions process for recovering wider locational costs); to remove the residual element of the entry (generation) TNUoS capacity charge (and instead recover this through a commodity charge based on £/kWh); and to revise the zoning criteria, which would now apply to the zonal auction reserve prices. It is proposed that such zones would be set by reference to a zonal definition methodology which would be described in a separate statement.

Further, a mechanism would need to be implemented in the Use of System Charging Methodology to resolve any under- or over-recoveries of auction revenues. It is anticipated that this would be through the commoditised residual charge, although further mechanisms may be required to accommodate potential extreme scenarios.

Changes to National Grid's Transmission Licence would be required to give effect to the IECR, the zonal definition methodology, and to define zonal baseline capacities. Additionally, alterations to the Transmission Owner revenue restriction, potentially in the form of additional incentive schemes, might be implemented. Changes to the licences of the other Transmission Licensees may also be required to define zonal baseline capacities and introduce additional incentive schemes.

Amendments to the System Operator – Transmission Owner Code (STC) might be required to ensure that the release of incremental capacity in Scotland was in line with the IECR. Additional STC changes may be required to "back-off" any other changes to National Grid's User facing obligations.

Changes to the GB Security and Quality of Supply Standards (SQSS) are likely to be required, due to the definition of access rights on a fungible zonal basis, and to accommodate the release of incremental capacity under the IECR.

Justification for Proposed Amendment with Reference to Applicable CUSC Objectives** *(mandatory by proposer)*:

The proposed amendment would better facilitate the achievement of Applicable CUSC Objective (a), the efficient discharge by the licensee of the obligations imposed upon it under the Act and by the licence, in that the release of capacity at value, together with the improved investment signals that would result from temporally defined bookings of long-term capacity, would better allow National Grid as the licensee to discharge its obligation under the Act to develop and maintain an efficient, co-ordinated and economical system of electricity transmission.

The proposed amendment would also better facilitate the achievement of Applicable CUSC Objective (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, as:

- Existing and new generators would be able to bid for existing transmission access rights on an equal basis, and such rights would be allocated to those that valued them most highly

- Existing capacity could be reallocated with certainty to new entrants as a result of the firm bookings of capacity made through the auctions process by existing generators; and

- The enhanced transparency in the commercial frameworks of required User commitments and increased certainty would address the perceived barriers to entry, thereby providing more confidence in the firmness of capacity applications, and increasing competition.

Details of Proposer: Organisation's Name:	National Grid Electricity Transmission plc
Capacity in which the Amendment is being proposed: (i.e. CUSC Party, BSC Party or "energywatch")	CUSC Party
Details of Proposer's Representative: Name: Organisation: Telephone Number: Email Address:	Andrew Truswell National Grid 01926 656369 andrew.truswell@uk.ngrid.com
Details of Representative's Alternate: Name: Organisation: Telephone Number: Email Address:	Duncan Burt National Grid 01926 656703 duncan.burt@uk.ngrid.com
Attachments (Yes/No): No **If Yes, Title and No. of pages of each Attachment:**	

Notes:

1. Those wishing to propose an Amendment to the CUSC should do so by filling in this "Amendment Proposal Form" that is based on the provisions contained in Section 8.15 of the CUSC. The form seeks to ascertain details about the Amendment Proposal so that the Amendments Panel can determine more clearly whether the proposal should be considered by a Working Group or go straight to wider National Grid Consultation.

2. The Panel Secretary will check that the form has been completed, in accordance with the requirements of the CUSC, prior to submitting it to the Panel. If the Panel Secretary accepts the Amendment Proposal form as complete, then he will write back to the Proposer informing him of the reference number for the Amendment Proposal and the date on which the Proposal will be considered by the Panel. If, in the opinion of the Panel Secretary, the form fails to provide the information required in the CUSC, then he may reject the Proposal. The Panel Secretary will inform the Proposer of the rejection and report the matter to the Panel at their next meeting. The Panel can reverse the Panel Secretary's decision and if this happens the Panel Secretary will inform the Proposer.

   The completed form should be returned to:

   Beverley Viney
   Panel Secretary
   Commercial Frameworks
   National Grid
   National Grid House
   Warwick Technology Park
   Gallows Hill
   Warwick
   CV34 6DA

   Or via e-mail to: Beverley.Viney@uk.ngrid.com

   (Participants submitting this form by email will need to send a statement to the effect that the proposer acknowledges that on acceptance of the proposal for consideration by the Amendments Panel, a proposer which is not a CUSC Party shall grant a licence in accordance with Paragraph 8.15.7 of the CUSC. A Proposer that is a CUSC Party shall be deemed to have granted this Licence).

3. Applicable CUSC Objectives** - These are defined within the National Grid Electricity Transmission plc Licence under Section C7F, paragraph 15. Reference should be made to this section when considering a proposed amendment.

ANNEX 8 – DRAFT SO LONG TERM RELEASE METHODOLOGY STATEMENT

The following draft documents were released by National Grid to Working Group 2 as part of its consideration of the auction methodology. The first version of the statement was prepared as part of the consideration of a Price based auction. The second version of the statement was prepared as part of the consideration of a capacity and duration based auction.

Methodology based on price auction

SO Long Term Release Methodology Statement

Purpose of this document

This document provides a description of the mechanism by which The Company will offer Transmission Entry Capacity (TEC) for sale via the Long Term auction process.

It also describes the methodology that The Company will use to determine whether to release TEC to Users primarily in the unconstrained period i.e. beyond investment lead times and details the circumstances when The Company will accept applications for incremental TEC from Users, including the level of financial commitment required from Users to underpin such an application.

Contents

General Information

Background

1. The working assumption is that this document will be incorporated into the CUSC and governed by the processes of the CUSC.

2. Definitions used within this document will be as per the CUSC.

The Company's Obligations

3. This section to be completed once the obligations are fully understood and funding arrangements are established such that if The Company takes on increased obligations to release capacity there is appropriate extra funding.

Chapter 1 - Principles

Purpose of the Methodology Statement

4. The purpose of this document is to provide a description of the mechanism by which The Company will offer Transmission Entry Capacity (TEC) for sale via the Long Term Auction Process.

5. It also describes the methodology that The Company will use to determine whether to release TEC to Users primarily in the unconstrained period i.e. beyond investment lead times and details the circumstances when The Company will accept applications for incremental TEC from Users, including the level of financial commitment required from Users to enable such an application to be successful.

Summary of the methodology underlying the Auction Process

6. The following provides a brief overview of the tasks which will take place as part of the auction process:

   - Establish the physical boundary limits based on SQSS security criteria;
   - Establish demand in each [Charging Zone];
   - Establish the maximum baseline and incremental capacity that is available for each boundary for each year;
   - Establish for each boundary which zones participate in the flows across them;
   - For boundaries that have a demand of more than 1500 MW behind then set the participation factor to 83%. Additional changes to participation factors may be needed to deal with specific local conditions at some boundaries;
   - Enhance the England-Scotland boundary to include the BETTA transition arrangements;
   - Publish market information covering baseline capacity at boundaries / zones and incremental capacity for each year;
   - Invite bids for capacity at each of the Nodes for each of the years;
   - Run the boundary flow auction to maximise bid income whilst ensuring that the flows across each boundary is not exceeded;
   - [Set the cleared price to the lowest price that has been accepted behind the boundary];
   - Publish the results of each auction round promptly to the market and allow for revision (between rounds) of bid price and volume with a reduction in volume being only reversible if another party subsequently reduces volume behind the same boundary;
   - Revision of bids and volume is allowed until no further movement takes place.

Chapter 2 – Auction Process

Introduction and the product being offered for sale

7. This document considers the allocation of TEC at a particular Node in any Financial Year.

8. A User shall apply for TEC at a Node as part of the Long Term auction process, but the rationale surrounding the release of TEC will be made by reference to the availability of Boundary Capability at the various Boundaries on the System in accordance with the methodology outlined within Chapter [3] of this document.

9. By submitting a bid as part of the Long Term auction process for TEC at a Node for a particular Financial Year, a User agrees to pay by way of [TEC Charges] the resultant [cleared price/bid price] for the TEC allocated in accordance with this Chapter for the relevant Financial Year.

10. In respect of a Boundary and in relation to each day of a particular Financial Year:

    (a) Baseline Annual Boundary Capability is the amount of Boundary Capability which The Company is required to make available to Users pursuant to [either the Licence or the CUSC];

    (b) Incremental Annual Boundary Capability is the amount of Boundary Capability (if any) in excess of the Unsold Annual Boundary Capability which The Company may (but shall not be required to) invite applications for as part of the TEC invitation; and

    (c) Unsold Annual Boundary Capability is the amount of Boundary Capability that The Company still has an obligation to make available as at the time of issuing the TEC invitation. *[Note that this could be remaining unsold baseline or unsold incremental from previous auction release]*

Annual Invitation Process

11. Between 1 September and 30 October during each Financial Year, The Company will invite, and Users may make, applications for TEC in respect of each Node (the TEC invitation dates).

12. The Company will invite applications for TEC for each of the Financial Years for Financial Year + 1 to Financial Year + 40 for such aggregate amounts of TEC as is specified in the TEC invitation.

13. By no later than 2 months before the first TEC invitation date in any Financial Year, The Company will notify Users of the [applicable reserve prices] [or any other prices] to apply in respect of each [Boundary/Charging Zone] for the purpose of the initial TEC invitation. In addition, The Company will issue the initial Auction Model to Users.

14. The Company's initial TEC invitation will specify:

(a) The dates on which applications pursuant to the TEC invitation may be made, which will be a period of [nn] [consecutive] Business Days (the TEC invitation period); *[this may not be consecutive days if Users want to have time between rounds to fully understand the implications of the previous round's bids]*

(b) For each Boundary and in respect of each of Financial Year +1 to Financial Year + 40, the Available Annual Boundary Capability; *[this will consist of the baseline capacity and show how the incremental capacity can ramp up over time as and when extra capacity can be offered for sale].*

(c) [and the applicable reserve price function which exists for each [Boundary/Charging Zone] [as set out within the Statement of Use of System Charges]];

(d) The manner in which each of the Nodes relate to the various Boundaries [and/or Charging Zones] on the System; and *[in the form of a Matrix of mappings so that Users may determine how TEC at a particular Node relates to Boundary Capability].*

(e) The details of the LCN Register and the Wider Access Register.

15. By no later than 15 August immediately before the first TEC invitation date in any Financial Year, The Company will issue Users with the final TEC invitation and the final version of the Auction Model.

16. The Company's final TEC invitation will specify:

(a) The dates on which applications pursuant to the TEC invitation may be made, which will be a period of [nn] [consecutive] Business Days (the TEC invitation period); *[this may not be consecutive days if Users want to have time between rounds to fully understand the implications of the previous round's bids]*

(b) For each Boundary and in respect of each of Financial Year +1 to Financial Year + 40, the Available Annual Boundary Capability; *[this will consist of the baseline capacity and show how the incremental capacity can ramp up over time as and when extra capacity can be offered for sale].*

(c) [and the applicable reserve price curve which exists for each [Boundary/Charging Zone] [as set out within the Statement of Use of System Charges]];

(d) The manner in which each of the Nodes relate to the various Boundaries [and/or Charging Zones] on the System; and *[in the form of a Matrix of mappings so that Users may determine how TEC at a particular Node relates to Boundary Capability].*

(e) The LCN Register and the Wider Access Register.

[the rationale behind an initial invitation and a final invitation is to take account of any referred offers for LCN]

17. The Available Annual Boundary Capability for a Boundary is, in respect of a Financial Year during Financial Year +1 to Financial Year + 40 (inclusive), not less than the sum of:

(a) Unsold Annual Boundary Capability (if any); and
(b) Incremental Annual Boundary Capability (if any)

18. A User may not apply for or be registered as holding TEC at a Node in an amount less than [1 MW] (the minimum eligible amount).

19. Users may not apply for TEC in any Financial Year unless they have a valid LCN offer applying for that particular Financial Year (or part thereof) in place by one Business Day prior to 15 August immediately before the TEC invitation period.

Annual Auction Application Process

20. Users may apply for TEC for each of Financial Year + 1 to Financial Year + 40 (inclusive) in respect of a Node on each day of the TEC invitation period.

21. Each application for TEC in respect of Financial Year +1 to Financial Year + 40 (inclusive) will specify:

(a) The identity of the User;
(b) The Node at which capacity is required;
(c) The Financial Year(s) being applied for;
(d) The amount [(not less than the minimum eligible amount)] of TEC applied for (in MW) during the Financial Year(s);
(e) The minimum amount of TEC which they would be willing to be allocated; *[this is to allow Users the ability to signal that were bids to be pro-rated, there is a minimum amount of TEC which they would wish to be allocated and if the allocation was below this, then the assumption is that the bid would be rejected and not allocated]* and
(f) The price (being [either an applicable [Boundary/Charging Zone] reserve price applicable to the particular Node or a price higher than the applicable reserve price]) in respect of which the User is applying for the amount of TEC (in £/MW to 2 decimal places (i.e to the nearest penny)).

22. A bid for TEC may be submitted, withdrawn or amended between 08:00 hours until 17:00 hours on each day of the TEC invitation period unless the auction has reached Stability (in which case the auction has closed).

23. On any day of the TEC invitation period, a User may be registered as holding a maximum of 5 bids for TEC per BMU per Node per Financial Year.*[Bids are additive not mutually exclusive, hence assumption is that this allows the User flexibility to put in a series of bids at different prices]*

24. The Company will reject a bid for TEC submitted on a TEC invitation date if it does not comply with the requirements of this Chapter. *[this includes having a valid LCN]*

25. There will be a validation process included as part of the User posting bids to both allow them to confirm that they wish to proceed with the bids and to ensure that they know that a particular bid has been received.

26. *[There will need to be a link back to any limitations under the CUSC around bids being placed which exceed any Credit limits? Suggest there would be a number of days when Users will need to post credit, i.e. within [5] business days, else bids are rejected – still needs to be discussed]*

Stability of Annual Auction Application Process

27. The Long Term Auction will close early if Stability is reached, but will not close before the [6th] day of the TEC invitation period. *[i.e. auction open for a minimum of [5] days]*

28. Stability is reached if in respect of any TEC invitation date, the cleared price after 17:00 for a particular [Boundary/Charging Zone and Financial Year combination] on that TEC invitation date does not change by more than £0.05/MW compared to the corresponding prevailing cleared price in respect of bids submitted by Users by 17:00 hours on the two immediately preceding TEC invitation date in all but 2 or fewer [Boundary/Charging Zone(s) and Financial Year combinations].

29. In the event that the auction has closed following Stability being reached:

(a) The Company will not later than 20:00 on that day of the TEC invitation period notify Users that the TEC invitation period has ended; and
(b) Users shall not be allowed to submit and The Company will not accept any further TEC bids in respect of the TEC invitation.

Annual Auction Allocation Process

30. [Only bids at or above the applicable [Boundary/Charging Zone] reserve price function will be considered when allocating TEC and therefore all bids below this reserve price function will be disregarded.]

31. For each Financial Year, valid bids [at or above the applicable reserve price function] for TEC will be allocated according to price applicable for each [Boundary/Charging Zone].

32. If in any Financial Year, the sum of all the bids placed relating to a particular [Boundary/Charging Zone] is equal to or below the Actual Available Annual Boundary Capability applicable to that [Boundary/Charging Zone] then TEC will be allocated in the amount of TEC applied for.

33. If in any Financial Year, the sum of all the bids placed relating to a particular [Boundary/Charging Zone] is above the Actual Available Annual Boundary Capability applicable to that [Boundary/Charging Zone] then the bids will be ranked in order of price, with the highest price being the first considered.

34. In that Financial Year, TEC will then be allocated in the amount of TEC applied for to the highest priced bids first, then the next highest such that the TEC will be allocated up to the Actual Available Boundary Capability where possible.

35. If in any Financial Year there are equally priced bids, then TEC will be allocated pro rata to the amount of TEC applied for provided that the amount to be allocated is above that User's minimum amount as specified as part of that User's bid. If any initial allocation would be below that User's minimum amount, then that User's bid will be disregarded and the allocation will be made between the valid bids which remain. However, in the event that more than one User has specified a minimum amount and the initial allocated amount would be below the minimum amount, then bids will be disregarded in order of value such that the User's bids which provide the least value (in terms of revenue less cost) will be the first bid to be disregarded (and so on) such that the bids can be allocated provided that the amount is above any User's minimum amount.

36. [In any Financial Year and for each [Boundary/Charging Zone], the price paid (in £/MW) of the last valid bid to which TEC was allocated sets the applicable cleared price.]

37. Once the Actual Available Boundary Capability in any Financial Year has been allocated any remaining bids relating to that particular Financial Year will remain unsatisfied.

38. The price paid (in £/MW) by each User in relation to the amount of TEC which it is registered as holding in a particular Financial Year shall be the [applicable Boundary/Charging Zone cleared price/bid price] which has been determined with reference to the Actual Available Annual Boundary Capability for that particular Financial Year. *[Note that allocation takes place on the actual bid amounts, but Users pay either the bid price or the cleared price]*

39. The process described in Paragraphs [30] to [38] will be repeated for each of Financial Year + 1 to Financial Year + 40 (inclusive).

40. The Actual Available Annual Boundary Capability for each Boundary which is available to be allocated is, in respect of a Financial Year during Financial Year +1 to Financial Year + 40 (inclusive), not less than the sum of:

    (a) Unsold Annual Boundary Capability (as is determined prior to the TEC invitation);
    (b) Any Incremental Annual Boundary Capability (which will not exceed the Available Annual Boundary Capability in that Financial Year as published in the TEC invitation) which The Company is required to make available pursuant to the Incremental Release Methodology as described within [Chapter 3] of this document; and
    (c) [Any additional Annual Boundary Capability which The Company in its sole discretion determines to make available to Users.]

Annual Auction Information Process

41. By 20:00 on each day in the TEC invitation period, The Company will calculate and notify Users of:

    (a) The bid amount (MW) and [cleared] price (£/MW) for each Financial Year during Financial Year + 1 to Financial Year + 40 of the prevailing bids and the relevant Node which would be allocated were the auction to close after that particular day in the TEC invitation period; *[Note that working assumption is for all information to be available to all Users]*
    (b) The Actual Available Annual Boundary Capability for each Boundary which is available to be allocated in respect of a Financial Year during Financial Year +1 to Financial Year + 40 were the auction to close after that particular day in the TEC invitation period [and an indication of the amount of Incremental Annual Boundary Capability which would be released];and
    (c) An indication of the level of changes between the previous two rounds of the auction such that it would enable Users to gauge the likelihood of stability being reached.

42. Once the auction has closed, The Company will, not later than [some time – depends on funding debate re provision of incremental – it is two months in the Gas regime] following the last TEC invitation date, inform each User of those bids which have been accepted and the amount of TEC which it is registered as holding for each Financial Year in respect of a Node. *[the timing of being able to confirm allocation amounts to Users depends on any limitations/restrictions in the licence]*

43. Within one Business Day after any notification under Paragraph [42] above, The Company will notify all Users of:

(a) The bid amount (MW) and [cleared] price (£/MW) for each Financial Year during Financial Year + 1 to Financial Year + 40 of the bids and the relevant Node which were allocated;
(b) The Actual Available Annual Boundary Capability for each Boundary which was available to be allocated in respect of a Financial Year during Financial Year +1 to Financial Year + 40 [and an indication of the amount of Incremental Annual Boundary Capability which would be released];
(c) [The number of Users who submitted successful bids and the number of Users who submitted unsuccessful bids]; and
(d) The weighted average price of the allocated capacity bids.

44. Following allocation, but before the following 1 April, the successful bids will be recorded in the Users' bilateral agreements and published in the Wider Access Register.

45. [Updated Annual Boundary Capabilities following the auction would need to be recorded somewhere and published.]

Chapter 3 – Incremental release methodology

Decision making applied

46. The information for considering whether or not to release incremental TEC in any Financial Year up to the level of Available TEC as published within the TEC invitation will be based on indications of Users' demand for TEC as revealed by the application process described in Chapter 2 above.

47. The Boundary Constraint Model has been developed such that the sum of the revenue derived from accepted bids (being [either the cleared price or the bid price]) for TEC less any reinforcement costs is maximised over the entire system subject to a number of linear constraints which ensure that net generation behind each boundary is less than or equal to that particular Boundary's capability as determined after the release of incremental boundary capability, i.e. the Actual Available Annual Boundary Capability.

Procedure for Allocating Incremental TEC

48. The following section outlines the methodology which is to be applied to determine whether any Incremental Annual Boundary Capability has been triggered in any Financial Year (and subsequent Financial Years). If the test is passed, then there is a presumption that incremental TEC is released at the relevant Node(s) from the relevant Financial Year.

49. For each Boundary, simultaneously across all Boundaries, consider the first year for which Users signal (by placing valid bids) a requirement for TEC above the prevailing Actual Available Annual Boundary Capability.

50. In order to establish if there is a sufficient amount of Long Term User Commitment to underpin the release of incremental TEC, the valid bids in that Financial Year plus the subsequent 7 Financial Years will be considered. *[i.e. only look over 8 years of bids for a signal for incremental]*

51. If there is:

    (a) Demand for that particular level of incremental TEC in the subsequent 7 years (i.e. 8 years worth in total); and/or
    (b) The net present value of the additional bid revenue which would be generated across the Financial Years for which that particular level of incremental TEC has been signalled is greater than or equal to 50% of [that required by reference to the reserve price function]

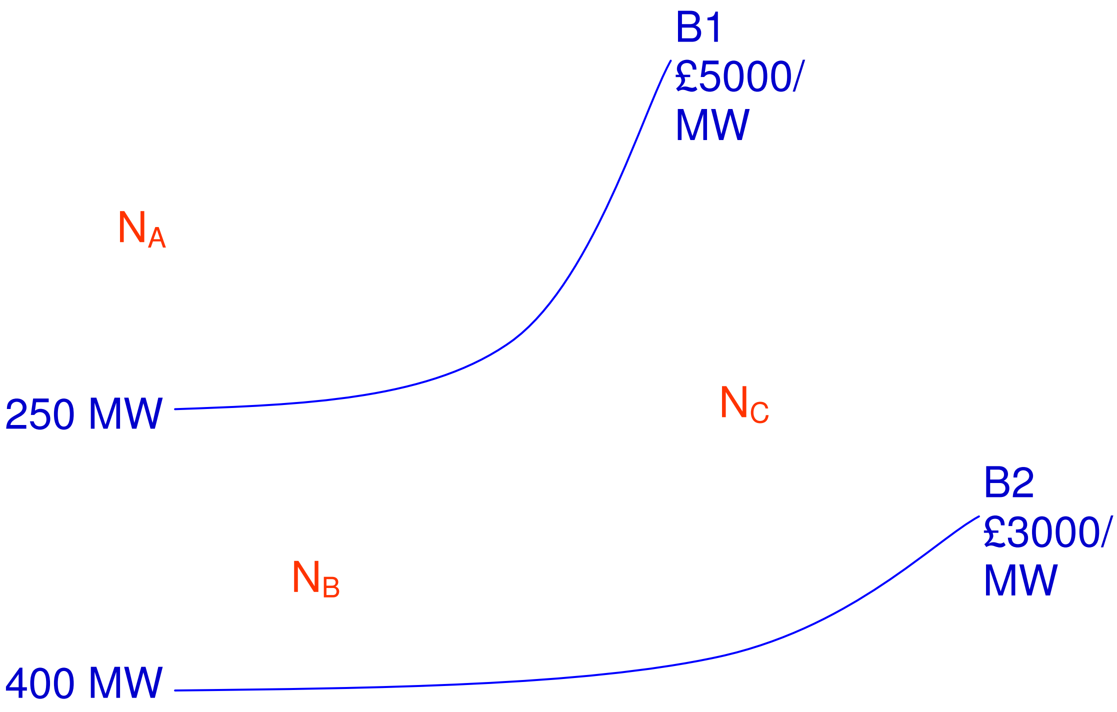
    then this means that the test for the release of such incremental TEC has been passed and this will be released to Users as part of the Actual Available Annual Boundary Capability and allocated to Users in accordance with the relevant procedure.

Simple example of Allocating Incremental TEC – single year example

52. The following simplified example illustrates how the process will work where only two Boundaries are considered and there are applicable reserve prices.

53. Consider two adjacent Boundaries on the system, B1 and B2. Assuming that prior to the auction taking place, the Actual Available Boundary Capability in the first Financial Year for B1 was 250 MW and for B2 400 MW.

54. Assume that there is only one Node, N_A, behind Boundary B1 and that there are two Nodes, N_B and N_C, behind Boundary B2 and that the applicable reserve prices commensurate with the Actual Available Boundary Capability are £5000/MW for B1 and £3000/MW for B2. Node N_A will therefore need to bid at least £5000/MW for its bids to be considered (for B1, but effectively £8000/MW for its bids to be considered at B2) and Nodes N_B and N_C will need to bid at least £3000/MW.



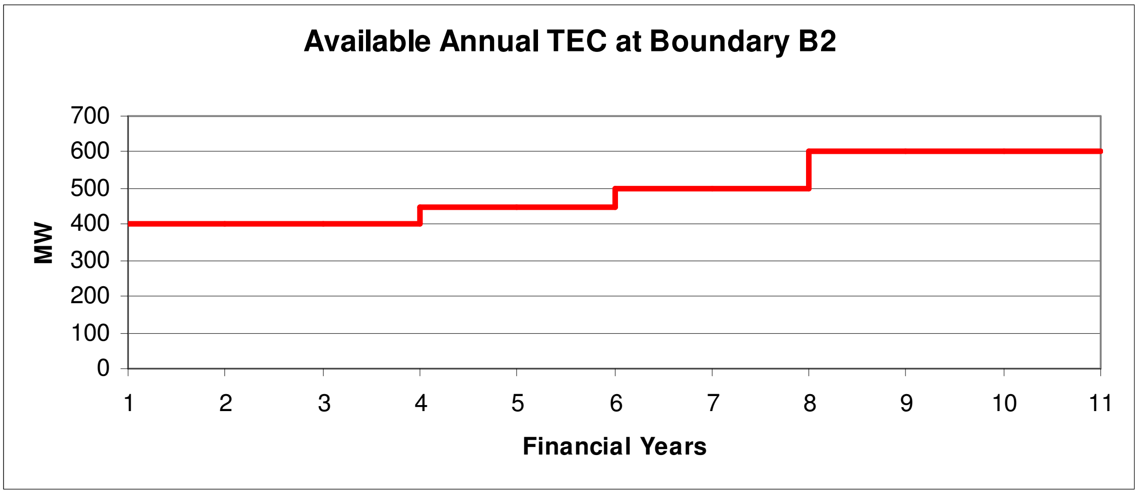
55. If Node N_A requires 200 MW, Node N_B requires 100 MW and Node N_C requires 150 MW and Node N_A bids £8000/MW, Node N_B bids £5000/MW and Node N_C bids £3000/MW, then the bids bid will be allocated as follows.

56. As there is no competition at the B1 Boundary, Node N_A will be allocated its 200 MW at that Boundary in full. There is however competition at the B2 Boundary as the total of the bids at B2 is in excess of the Actual Available Boundary Capability of 400 MW.

57. By considering only this one Financial Year in isolation, Node N_A will be allocated its 200 MW in full (and will pay its bid price of £8000/MW), Node N_B will be allocated its 100 MW in full (and will pay [either its bid price of £5000/MW or the cleared price of £3000/MW]) and Node N_C will only receive 100 MW (and will pay [£3000/MW which is both its bid price and the cleared price for the Charging Zone], but will not be allocated in full leaving 50 MW of its demand unsatisfied) as the bids are allocated to the highest priced bids first up to the Actual Available Boundary Capability.

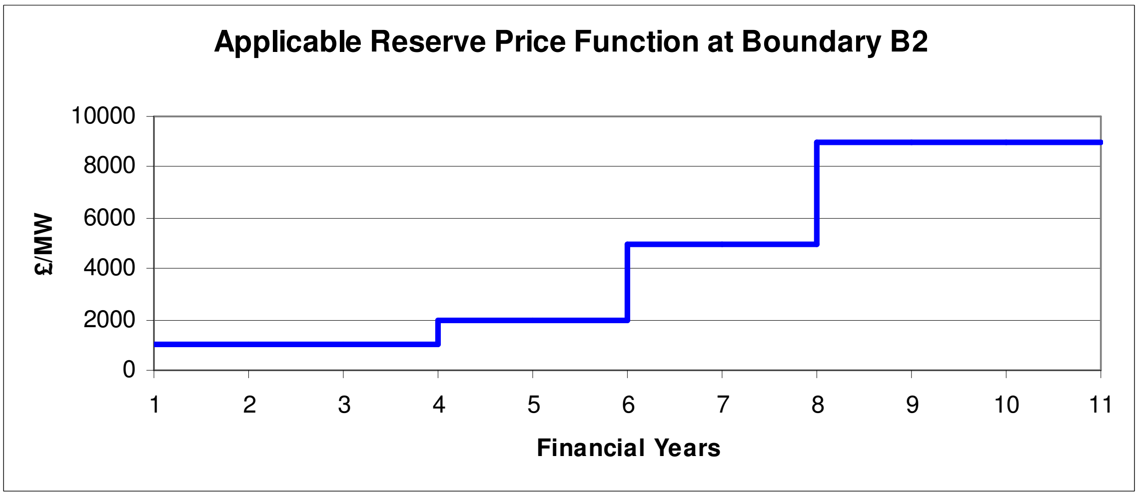
Simple example of Allocating Incremental TEC in a Pay-as bid auction with reserve prices – multi-year example

58. Taking the above example, further assume that as part of the TEC invitation, The Company indicated that it could provide an increasing level of Available Boundary Capability at Boundary B2 over a number of years as per the following profile:



59. This means that The Company is indicating that it could provide increased capacity at Boundary B2 from Financial Year 4 onwards.

60. Also assume that the reserve price function associated with this increase in Available Annual TEC at Boundary B2 was non-linear, such that the provision of the 400 MW had a reserve price set at £1000/MW, 450 MW a reserve price of £2000/MW, 500 MW a reserve price of £5000/MW and 600 MW a reserve price of £9000/MW, as shown by the following:



61. If the pattern of bids seen in the single year were to be repeated in the following 7 subsequent Financial Years, then as there would be 8 years in total of bids at or above the applicable reserve price, there would be enough Long Term User Commitment to justify the release of the extra 50 MW at Boundary B2. In that case from Financial Year 4 onwards the Available Actual Annual Boundary Capability at Boundary B2 would be increased to 450 MW from the previous value of 400 MW and all the bids would be allocated in full from that point onwards (and would pay [the cleared price/their bid prices]).

The following text shows how a version of the bidding process and allocation parts of the above statement could be changed to cater for a Capacity and Duration based auction.

Annual Invitation Process

1. Between 1 September and 30 October during each Financial Year, The Company will invite, and Users may make, applications for TEC in respect of each Node (the TEC invitation dates).

2. The Company will invite applications for TEC for each of the Financial Years for Financial Year + 1 to Financial Year + 40 for such aggregate amounts of TEC as is specified in the TEC invitation.

3. By no later than 2 months before the first TEC invitation date in any Financial Year, The Company will notify Users of the [applicable [long-run] prices relating to the Available Annual Boundary Capability] [or any other prices] to apply in respect of each [Boundary/Charging Zone] for the purpose of the initial TEC invitation. In addition, The Company will issue the initial Auction Model to Users.

4. The Company's initial TEC invitation will specify:

    (a) The dates on which applications pursuant to the TEC invitation may be made, which will be a period of [nn] [consecutive] Business Days (the TEC invitation period); *[this may not be consecutive days if Users want to have time between rounds to fully understand the implications of the previous round's bids]*
    (b) For each Boundary and in respect of each of Financial Year +1 to Financial Year + 40, the Available Annual Boundary Capability; *[this will consist of the baseline capacity and show how the incremental capacity can ramp up over time as and when extra capacity can be offered for sale]*.
    (c) [and the applicable [long-run] price function which exists for each [Boundary/Charging Zone] [as set out within the Statement of Use of System Charges]];
    (d) The manner in which each of the Nodes relate to the various Boundaries [and/or Charging Zones] on the System; and *[in the form of a Matrix of mappings so that Users may determine how TEC at a particular Node relates to Boundary Capability]*.
    (e) The details of the LCN Register and the Wider Access Register.

5. By no later than 15 August immediately before the first TEC invitation date in any Financial Year, The Company will issue Users with the final TEC invitation and the final version of the Auction Model.

6. The Company's final TEC invitation will specify:

    (a) The dates on which applications pursuant to the TEC invitation may be made, which will be a period of [nn] [consecutive] Business Days (the TEC invitation period); *[this may not be consecutive days if Users want to have time between rounds to fully understand the implications of the previous round's bids]*

(b) For each Boundary and in respect of each of Financial Year +1 to Financial Year + 40, the Available Annual Boundary Capability; *[this will consist of the baseline capacity and show how the incremental capacity can ramp up over time as and when extra capacity can be offered for sale].*

(c) [and the applicable [long-run] price curve which exists for each [Boundary/Charging Zone] [as set out within the Statement of Use of System Charges]];

(d) The manner in which each of the Nodes relate to the various Boundaries [and/or Charging Zones] on the System; and *[in the form of a Matrix of mappings so that Users may determine how TEC at a particular Node relates to Boundary Capability].*

(e) The LCN Register and the Wider Access Register.

[the rationale behind an initial invitation and a final invitation is to take account of any referred offers for LCN]

7. The Available Annual Boundary Capability for a Boundary is, in respect of a Financial Year during Financial Year +1 to Financial Year + 40 (inclusive), not less than the sum of:

   (a) Unsold Annual Boundary Capability (if any); and
   (b) Incremental Annual Boundary Capability (if any)

8. A User may not apply for or be registered as holding TEC at a Node in an amount less than [1 MW] (the minimum eligible amount).

9. Users may not apply for TEC in any Financial Year unless they have a valid LCN offer applying for that particular Financial Year (or part thereof) in place by one Business Day prior to 15 August immediately before the TEC invitation period.

Annual Auction Application Process

10. Users may apply for TEC for each of Financial Year + 1 to Financial Year + 40 (inclusive) in respect of a Node on each day of the TEC invitation period.

11. Each application for TEC in respect of Financial Year +1 to Financial Year + 40 (inclusive) will specify:

    (a) The identity of the User;
    (b) The Node at which capacity is required;
    (c) The Financial Year(s) being applied for;
    (d) The amount [(not less than the minimum eligible amount)] of TEC applied for (in MW) during the Financial Year(s);
    (e) The applicable Load Duration function for the Node (to be expressed as a % requirement for each of the [four] percentage of use categories of 100%, 75%, 50% and 25%) which will apply at that Node and
    (f) The buy-back price which is the price that the User is willing to accept in respect of that TEC were there to be a constraint associated with that amount of TEC being allocated (in £/MWh to 2 decimal places (i.e to the nearest penny)).

12. A bid for TEC may be submitted, withdrawn or amended between 08:00 hours until 17:00 hours on each day of the TEC invitation period unless the auction has reached Stability (in which case the auction has closed).

13. The Company will reject a bid for TEC submitted on a TEC invitation date if it does not comply with the requirements of this Chapter. *[this includes having a valid LCN]*

14. There will be a validation process included as part of the User posting bids to both allow them to confirm that they wish to proceed with the bids and to ensure that they know that a particular bid has been received.

15. *[There will need to be a link back to any limitations under the CUSC around bids being placed which exceed any Credit limits? Suggest there would be a number of days when Users will need to post credit, i.e. within [5] business days, else bids are rejected – still needs to be discussed]*

Stability of Annual Auction Application Process

16. The Long Term Auction will close early if Stability is reached, but will not close before the [6th] day of the TEC invitation period. *[i.e. auction open for a minimum of [5] days]*

17. [Stability is reached if in respect of any TEC invitation date, the [average price per MW over all allocated TEC, i.e. both Long-run and Short-run priced TEC] after 17:00 [over the entire system and Financial Year combination] [for a particular [Boundary/Charging Zone and Financial Year combination] on that TEC invitation date does not change by more than [£x/MW] compared to the corresponding prevailing [average price] in respect of bids submitted by Users by 17:00 hours on the two immediately preceding TEC invitation dates [in all but 2 or fewer [Boundary/Charging Zone(s) and Financial Year combinations]].

18. In the event that the auction has closed following Stability being reached:

    (a) The Company will not later than 20:00 on that day of the TEC invitation period notify Users that the TEC invitation period has ended; and
    (b) Users shall not be allowed to submit and The Company will not accept any further TEC bids in respect of the TEC invitation.

Annual Auction Allocation Process

19. In any Financial Year, the amount of TEC allocated to a User will be the amount applied for in MW. *[Note that all Users get what they bid for – the allocation process is all about setting the price that each User would pay for the different amounts of capacity they have been allocated.]*

20. If in any Financial Year, the sum of all the bids placed relating to a particular [Boundary/Charging Zone] is equal to or below the Actual Available Annual Boundary Capability applicable to that [Boundary/Charging Zone] then TEC will be allocated as [L-T] in the amount of TEC applied for.

21. If in any Financial Year, the sum of all the bids placed relating to a particular [Boundary/Charging Zone] is above the Actual Available Annual Boundary Capability applicable to that [Boundary/Charging Zone] then the bids will be allocated as [Long-run priced] pro rata to the amount of TEC applied for using the [agreed algorithm – to be described when developed].

22. If in any Financial Year the sum of all the bids placed relating to a particular [Boundary/Charging Zone] is above the Actual Available Annual Boundary Capability applicable to that [Boundary/Charging Zone], then following the application of the pro-ration rules described in paragraph [21], the remaining amount of TEC applied for by Users above the amount allocated as [Long-run priced] will be allocated to Users as [Short-run priced] [This could be explicit or implicit].

23. The price paid (in £/MW) by each User in relation to the amount of TEC which it is registered as holding in a particular Financial Year shall be the [weighted average price applicable to the [Long-run priced] and [Short-run priced] TEC allocated applicable at that Boundary/Charging Zone] which has been determined with reference to the Actual Available Annual Boundary Capability for that particular Financial Year.

24. The process described in Paragraphs [19] to [23] will be repeated for each of Financial Year + 1 to Financial Year + 40 (inclusive).

25. The Actual Available Annual Boundary Capability for each Boundary which is available to be allocated is, in respect of a Financial Year during Financial Year +1 to Financial Year + 40 (inclusive), not less than the sum of:

    (a) Unsold Annual Boundary Capability (as is determined prior to the TEC invitation);
    (b) Any Incremental Annual Boundary Capability (which will not exceed the Available Annual Boundary Capability in that Financial Year as published in the TEC invitation) which The Company is required to make available pursuant to the Incremental Release Methodology as described within [Chapter 3] of this document; and
    (c) [Any additional Annual Boundary Capability which The Company in its sole discretion determines to make available to Users.]

26. *[Allocation rules and pricing information to be worked up further once they've been finalised. Pricing could be on a £/MW for Long-run priced and £/MWh basis for Short-run or a weighted average capacity price as suggested above?]*

Annual Auction Information Process

27. By 20:00 on each day in the TEC invitation period, The Company will calculate and notify Users of:

    (a) The bid amount (MW) [subject to the weighted average price (£/MW)] [or subject to the [Long-run]] price (£/MW) and the amount (MW) subject to the (£/MWh) (short-run cost related price)] [or just an average £/MW] for each Financial Year during Financial Year + 1 to Financial Year + 40 of the prevailing bids and the relevant Node which would be allocated were the auction to close after that particular day in the TEC invitation period; *[Note that working assumption is for all information to be available to all Users]*
    (b) The Actual Available Annual Boundary Capability for each Boundary which is available to be allocated in respect of a Financial Year during Financial Year +1 to Financial Year + 40 were the auction to close after that particular day in the TEC invitation period [and an indication of the amount of Incremental Annual Boundary Capability which would be released];and

(c) An indication of the level of changes between the previous two rounds of the auction such that it would enable Users to gauge the likelihood of stability being reached.

Methodology based on a Capacity / Duration auction

SO Long Term Release Methodology Statement

Purpose of this document

This document provides a description of the mechanism by which The Company will offer Transmission Entry Capacity (TEC) for sale via the Long Term auction process.

It also describes the methodology that The Company will use to determine whether to release TEC to Users primarily in the unconstrained period i.e. beyond investment lead times and details the circumstances when The Company will accept applications for incremental TEC from Users, including the level of financial commitment required from Users to underpin such an application.

Contents

General Information

Background

1. The working assumption is that this document will be incorporated into the CUSC and governed by the processes of the CUSC.

2. Definitions used within this document will be as per the CUSC.

The Company's Obligations

3. This section to be completed once the obligations are fully understood and funding arrangements are established such that if The Company takes on increased obligations to release capacity there is appropriate extra funding.

Chapter 1 - Principles

Purpose of the Methodology Statement

4. The purpose of this document is to provide a description of the mechanism by which The Company will offer Transmission Entry Capacity (TEC) for sale via the Long Term Auction Process.

5. It also describes the methodology that The Company will use to determine whether to release TEC to Users primarily in the unconstrained period i.e. beyond investment lead times and details the circumstances when The Company will accept applications for incremental TEC from Users, including the level of financial commitment required from Users to enable such an application to be successful.

Summary of the methodology underlying the Auction Process

6. The following provides a brief overview of the tasks which will take place as part of the auction process:

   - Establish the physical boundary limits based on [SQSS security criteria];
   - Establish demand in each [Charging Zone];
   - Establish the maximum baseline and incremental capacity that is available for each boundary for each year;
   - Establish for each boundary which zones participate in the flows across them;
   - [For boundaries that have a demand of more than 1500 MW behind then set the participation factor to 83%. Additional changes to participation factors may be needed to deal with specific local conditions at some boundaries;]
   - Set the baseline capacity at the England-Scotland boundary to physical capability, i.e. do **not** include the BETTA transition arrangements *[Assumption is that any allocation above physical capability will be as Short-run priced TEC]*;
   - Publish market information covering baseline capacity at boundaries / zones and incremental capacity for each year;
   - Invite bids for capacity at each of the Nodes for each of the years;
   - Run the allocation to allow Users' bids to be satisfied in full;
   - If there is demand for capacity above Available capability then Users' bids will be satisfied as a combination of [Long-run priced] TEC and [Short-run priced] TEC. If not, then Users will only receive an offer for [Long-run priced] TEC;
   - Publish the results of each auction round promptly to the market and allow for revision (between rounds) of bid price and volume;
   - Revision of bids and volume is allowed until no further movement takes place;
   - Following the application of the Validation process, a User's allocation of TEC may be amended. If this happens, then any impacted Users may have their combination of [Long-run priced] TEC and [Short-run priced] TEC revised.

Chapter 2 – Auction Process

Introduction and the product being offered for sale

7. This document considers the allocation of TEC at a particular Node in any Financial Year.

8. A User shall apply for TEC at a Node as part of the Long Term auction process, but the rationale surrounding the release of TEC will be made by reference to the availability of Boundary Capability at the various Boundaries on the System in accordance with the methodology outlined within Chapter [3] of this document.

9. By submitting a bid as part of the Long Term auction process for TEC at a Node for a particular Financial Year, a User agrees to pay by way of [TEC Charges] the resultant [bid price(s)] for the TEC allocated in accordance with this Chapter for the relevant Financial Year.

10. In respect of a Boundary and in relation to each day of a particular Financial Year:

    (a) Baseline Annual Boundary Capability is the amount of Boundary Capability which The Company is required to make available to Users pursuant to [either the Licence or the CUSC];

    (b) Incremental Annual Boundary Capability is the amount of Boundary Capability (if any) in excess of the Unsold Annual Boundary Capability which The Company may (but shall not be required to) invite applications for as part of the TEC invitation; and

    (c) Unsold Annual Boundary Capability is the amount of Boundary Capability that The Company still has an obligation to make available as at the time of issuing the TEC invitation. *[Note that this could be remaining unsold baseline or unsold incremental from previous auction release]*

Annual Invitation Process

11. Between 1 September and 30 October during each Financial Year, The Company will invite, and Users may make, applications for TEC in respect of each Node (the TEC invitation dates).

12. The Company will invite applications for TEC for each of the Financial Years for Financial Year + 1 to Financial Year + 40 for such aggregate amounts of TEC as is specified in the TEC invitation.

13. By no later than 2 months before the first TEC invitation date in any Financial Year, The Company will notify Users of the [applicable [Long-run] prices] relating to the Available Annual Boundary Capability] [or any other prices] to apply in respect of each [Boundary/Charging Zone] for the purpose of the initial TEC invitation. In addition, The Company will issue the initial Auction Model to Users.

14. The Company's initial TEC invitation will specify:

    (f) The dates on which applications pursuant to the TEC invitation may be made, which will be a period of [nn] [consecutive] Business Days (the

TEC invitation period); *[this may not be consecutive days if Users want to have time between rounds to fully understand the implications of the previous round's bids]*

(g) For each Boundary and in respect of each of Financial Year +1 to Financial Year + 40, the Available Annual Boundary Capability; *[this will consist of the baseline capacity and show how the incremental capacity can ramp up over time as and when extra capacity can be offered for sale].*

(h) [and the applicable [Long-run] price which exists for each [Boundary/Charging Zone] [as set out within the Statement of Use of System Charges]];

(i) The manner in which each of the Nodes relate to the various Boundaries [and/or Charging Zones] on the System; and *[in the form of a Matrix of mappings so that Users may determine how TEC at a particular Node relates to Boundary Capability].*

(j) The details of the LCN Register and the Wider Access Register.

15. By no later than 15 August immediately before the first TEC invitation date in any Financial Year, The Company will issue Users with the final TEC invitation and the final version of the Auction Model.

16. The Company's final TEC invitation will specify:

(k) The dates on which applications pursuant to the TEC invitation may be made, which will be a period of [nn] [consecutive] Business Days (the TEC invitation period); *[this may not be consecutive days if Users want to have time between rounds to fully understand the implications of the previous round's bids]*

(l) For each Boundary and in respect of each of Financial Year +1 to Financial Year + 40, the Available Annual Boundary Capability; *[this will consist of the baseline capacity and show how the incremental capacity can ramp up over time as and when extra capacity can be offered for sale].*

(m) [and the applicable [Long-run] price which exists for each [Boundary/Charging Zone] [as set out within the Statement of Use of System Charges]];

(n) The manner in which each of the Nodes relate to the various Boundaries [and/or Charging Zones] on the System; and *[in the form of a Matrix of mappings so that Users may determine how TEC at a particular Node relates to Boundary Capability].*

(o) The LCN Register and the Wider Access Register.

[the rationale behind an initial invitation and a final invitation is to take account of any referred offers for LCN]

17. The Available Annual Boundary Capability for a Boundary is, in respect of a Financial Year during Financial Year +1 to Financial Year + 40 (inclusive), not less than the sum of:

(p) Unsold Annual Boundary Capability (if any); and
(q) Incremental Annual Boundary Capability (if any)

18. A User may not apply for or be registered as holding TEC at a Node in an amount less than [1 MW] (the minimum eligible amount).

19. Users may not apply for TEC in any Financial Year unless they have a valid LCN offer applying for that particular Financial Year (or part thereof) in place by one Business Day prior to 15 August immediately before the TEC invitation period.

Annual Auction Application Process

20. Users may apply for TEC for each of Financial Year + 1 to Financial Year + 40 (inclusive) in respect of a Node on each day of the TEC invitation period.

21. Each application for TEC in respect of Financial Year +1 to Financial Year + 40 (inclusive) will specify:

    (r) The identity of the User;
    (s) The Node at which capacity is required;
    (t) The Financial Year(s) being applied for; and
    (u) The amount [(not less than the minimum eligible amount)] of TEC applied for (in MW) during the Financial Year(s).

22. A bid for TEC may be submitted, withdrawn or amended between 08:00 hours until 17:00 hours on each day of the TEC invitation period unless the auction has reached Stability (in which case the auction has closed).

23. The Company will reject a bid for TEC submitted on a TEC invitation date if it does not comply with the requirements of this Chapter. *[this includes having a valid LCN]*

24. [A User will not be able to place a bid during the TEC invitation period for a higher amount of TEC in any Financial Year and Node combination than that which the User placed in that Financial Year at that particular Node during the first day of the TEC invitation period.] *[The rationale here was that if there was no restriction on Users being able to change volumes up or down, then in order to provide information to the market, all Users would need to submit their maximum requirements on day 1 of the auction]*

25. There will be a validation process included as part of the User posting bids to both allow them to confirm that they wish to proceed with the bids and to ensure that they know that a particular bid has been received.

26. *[There will need to be a link back to any limitations under the CUSC around bids being placed which exceed any Credit limits? Suggest there would be a number of days when users will need to post credit, i.e. within [5] business days, else bids are rejected – still needs to be discussed]*

Stability of Annual Auction Application Process

27. The Long Term Auction will close early if Stability is reached, but will not close before the [6th] day of the TEC invitation period. *[i.e. auction open for a minimum of [5] days]*

28. [Stability is reached if in respect of any TEC invitation date, the [average price per MW over all allocated TEC, i.e both the Long-run and Short-run priced TEC] after 17:00 [over the entire system and Financial Year combination] [for a particular [Boundary/Charging Zone and Financial Year combination]] on that TEC invitation date does not change by more than £x/MW compared to the corresponding prevailing [average price] in respect of bids submitted by Users by 17:00 hours on the two immediately preceding

TEC invitation date [in all but 2 or fewer [Boundary/Charging Zone(s) and Financial Year combinations]].

29. In the event that the auction has closed following Stability being reached:

(v) The Company will not later than 20:00 on that day of the TEC invitation period notify Users that the TEC invitation period has ended; and
(w) Users shall not be allowed to submit and The Company will not accept any further TEC bids in respect of the TEC invitation.

Annual Auction Allocation Process

30. In any Financial Year, the amount of TEC allocated to a User will be the amount applied for in MW. TEC will be allocated as a combination of [Long-run priced] TEC and [Short-run priced] TEC. *[Note that all Users get what they bid for – the allocation process is all about setting the price that each User would pay for the different amounts of capacity they have been allocated.]*

31. If in any Financial Year, the sum of all the bids placed relating to a particular [Boundary/Charging Zone] is equal to or below the Actual Available Annual Boundary Capability applicable to that [Boundary/Charging Zone] then TEC will be allocated as [Long-run priced] TEC in the amount of TEC applied for.

32. If in any Financial Year, the sum of all the bids placed relating to a particular [Boundary/Charging Zone] is above the Actual Available Annual Boundary Capability applicable to that [Boundary/Charging Zone] then the bids will be allocated as a combination of [Long-run priced] TEC and [Short-run priced] TEC in the following manner:

7 the allocation of [Long-run priced] TEC will be made pro-rata to the amount of TEC applied for by all Users at the relevant [Boundary/Charging Zone] using the [agreed algorithm – to be described when developed]; and
8 the remaining amount of TEC applied for by Users above the amount allocated as [Long-run priced] TEC will be allocated to Users as [Short-run priced] TEC. *[Note that this could be explicit or implicit depending on how the charging is developed]]*

33. The price paid by each User in relation to the amount of [Long-run priced] TEC which it is registered as holding in a particular Financial Year shall be the applicable [Long-run price] (in £/MW) which has been determined with reference to the Actual Available Annual Boundary Capability for that particular Financial Year.

34. The price paid by each User in relation to the amount of [Short-run priced] TEC which it is registered as holding in a particular Financial Year shall be the [Short-run price] (in £/MWh) which is applicable at the time that the particular User is using that [Short-run priced] TEC [and there is a constraint on that part of the Transmission System]. *[Assumption here is that there is a charge per MWh for Short-run (and would only apply if constraint active) and a charge per MW for Long-run would be as set out in the Charging Statement. However, final charging arrangements would need to be decided via a Pricing consultation]*

35. The process described in Paragraphs [30] to [34] will be repeated for each of Financial Year + 1 to Financial Year + 40 (inclusive).

36. The Actual Available Annual Boundary Capability for each Boundary which is available to be allocated is, in respect of a Financial Year during Financial Year +1 to Financial Year + 40 (inclusive), not less than the sum of:

    (a) Unsold Annual Boundary Capability (as is determined prior to the TEC invitation);
    (b) Any Incremental Annual Boundary Capability (which will not exceed the Available Annual Boundary Capability in that Financial Year as published in the TEC invitation) which The Company is required to make available pursuant to the Incremental Release Methodology as described within [Chapter 3] of this document; and
    (c) [Any additional Annual Boundary Capability which The Company in its sole discretion determines to make available to Users.]

Annual Auction Information Process

37. By 20:00 on each day in the TEC invitation period, The Company will calculate and notify Users of:

    (d) The bid amount (MW) [subject to the [Long-run price] (in £/MW)] and the bid amount (MW) [subject to the [Short-run price] (in £/MWh)] for each Financial Year during Financial Year + 1 to Financial Year + 40 of the prevailing bids and the relevant Node which would be allocated were the auction to close after that particular day in the TEC invitation period; *[Note that working assumption is for all information to be available to all Users]*
    (e) The Actual Available Annual Boundary Capability for each Boundary which is available to be allocated in respect of a Financial Year during Financial Year +1 to Financial Year + 40 were the auction to close after that particular day in the TEC invitation period [and an indication of the amount of Incremental Annual Boundary Capability which would be released];and
    (f) An indication of the level of changes between the previous two rounds of the auction such that it would enable users to gauge the likelihood of stability being reached.

38. Once the auction has closed, The Company will, not later than [some time – depends on funding debate re provision of incremental – it is two months in the Gas regime] following the last TEC invitation date, inform each User of those bids which have been accepted and the amount of TEC which it is registered as holding for each Financial Year in respect of a Node. *[the timing of being able to confirm allocation amounts to Users depends on any limitations/restrictions in the licence]*

39. Within one Business Day after any notification under Paragraph [38] above, The Company will notify all Users of:

    (g) The bid amount (MW) [subject to the [Long-run price] (in £/MW)] and the bid amount (MW) [subject to the [Short-run price] (in £/MWh)] for each Financial Year during Financial Year + 1 to Financial Year + 40 of the bids and the relevant Node which were allocated;
    (h) The Actual Available Annual Boundary Capability for each Boundary which was available to be allocated in respect of a Financial Year during Financial Year +1 to Financial Year + 40 [and an indication of the amount of Incremental Annual Boundary Capability which would be released];

(i) [The number of Users who submitted successful bids and the number of Users who submitted unsuccessful bids]; and
(j) The weighted average price of the allocated capacity bids.

40. Following allocation, but before the following 1 April, the successful bids will be recorded in the Users' bilateral agreements and published in the Wider Access Register.

41. [Updated Annual Boundary Capabilities following the auction would need to be recorded somewhere and published.]

Validation Process

42. Where a User has been allocated an amount of [Long-run priced] TEC and [Short-run priced] TEC and the User fails to adequately validate that it can export onto the GB Transmission System up to the level of TEC allocated to it, The Company may subsequently reduce a User's allocation of TEC (both [Long-run priced] and [Short-run priced]).

43. Following the reduction of a particular User's TEC as a consequence of the Validation process, The Company will re-run the allocation process outlined in Paragraphs [30] to [36] above. This would not only result in an amendment to the proportion of [Long-run priced] and [Short-run priced] TEC which that User would now be registered as holding, but would also affect any other Users who were subject to the original pro-ration process. It is anticipated, in these circumstances, that where there has been a reduction of a particular User's TEC, that those other affected Users should see an increase to the proportion of [Long-run priced] and a reduction to the [Short-run priced] TEC which those other affected Users have as their revised holding.

44. Within one Business Day after the re-application of the allocation process outlined in Paragraph [43] above, The Company will inform each affected User of its revised bid amounts which have now been accepted and the amount of TEC (both [Long-run priced] and [Short-run priced]) which it is registered as holding for each Financial Year in respect of a Node.

45. Within one further Business Day after any notification under Paragraph [44] above, The Company will notify all Users of:

(k) The revised bid amount (MW) [subject to the [Long-run price] (in £/MW)] and the bid amount (MW) [subject to the [Short-run price] (in £/MWh)] for each Financial Year during Financial Year + 1 to Financial Year + 40 of the bids and the relevant Node which were allocated;
(l) The Actual Available Annual Boundary Capability for each Boundary which was available to be allocated in respect of a Financial Year during Financial Year +1 to Financial Year + 40 [and an indication of the amount of Incremental Annual Boundary Capability which would be released];
(m) [The number of Users who submitted successful bids and the number of Users who submitted unsuccessful bids]; and
(n) The weighted average price of the allocated capacity bids.

46. Following any revised allocation process, the revised successful bids will be recorded in the Users' bilateral agreements and published in the Wider Access Register.

Chapter 3 – Incremental release methodology

Decision making applied

47. The information for considering whether or not to release Incremental TEC in any Financial Year up to the level of Available TEC as inferred by the Available Annual Boundary Capability figures published within the TEC invitation will be based on indications of Users' demand for TEC as revealed by the application process described in Chapter 2 above.

Procedure for Allocating Incremental TEC

48. The following section outlines the methodology which is to be applied to determine whether any Incremental Annual Boundary Capability has been triggered in any Financial Year (and subsequent Financial Years). If the test is passed, then there is a presumption that Incremental TEC is released at the relevant Node(s) from the relevant Financial Year.

49. For each Boundary, simultaneously across all Boundaries, consider the first year for which Users signal (by placing valid bids) a requirement for TEC above the prevailing Actual Available Annual Boundary Capability.

50. In order to establish if there is a sufficient amount of Long Term User Commitment to underpin the release of incremental TEC, the valid bids in that Financial Year plus the subsequent 7 Financial Years will be considered. *[i.e. only look over 8 years of bids for a signal for incremental]*

51. If there is demand for that particular level of Incremental TEC in the subsequent 7 years (i.e. 8 years' worth in total) then this means that the test for the release of such Incremental TEC has been passed and this will be released to Users as part of the Actual Available Annual Boundary Capability and allocated to Users in accordance with the relevant procedure. *[Note that as there is no price signal from Users in this form of the auction, only 8 years' worth of bids considered to trigger the release of incremental capacity which will be priced as Long-run priced TEC]*

ANNEX 9 – RESULT OF WORKING GROUP VOTE

The Working Group voted on whether they believed the original or the Working Group alternatives are **better than the current baseline**. The result of the vote is described in the following table:

Proposal	Better	Not better	Abstained
Original	0	13	0
WGAA1	0	13	0
WGAA2	2	11	0
WGAA3	2	11	0

The Working Group voted on whether they believed the Working Group alternatives are **better than the original proposal.** The result of the vote is described in the following table:

Proposal	Better	Not better	Abstained
Original	-	-	-
WGAA1	1	8	4
WGAA2	3	6	4
WGAA3	4	8	1

The majority of the Working Group believed WGAA1 and WGAA2 were not better than the original or the baseline. The Chair of the Working Group with support of some members of the Working Group took forward WGAA1 and WGAA2. It was noted that if the group received an extension it was important to keep these alternatives under consideration in case further analysis of WGAA3 influences the assessment of these alternatives.

The Working Group voted on which of the proposals they believe best facilitates the applicable CUSC Objectives. The result of this vote is described in the following table:

Proposal	Best
Original	**0**
WGAA1	**0**
WGAA2	**0**
WGAA3	**3**
Abstained	**10**

ANNEX 10 – LEGAL TEXT TO GIVE EFFECT TO THE AMENDMENT AND WORKING GROUP ALTERNATIVE AMENDMENTS

ANNEX 11 – PRESENTATIONS MADE TO THE WORKING GROUP