**Appendix F**

# Balancing Principles Statement

**Effective from: 1 May 2002**

## Version Control

| Date | Version No. | Notes |
|---|---|---|
| 20.3.01 | 1.0 | Initial version |
| 1.5.02 | 2.0 | Revised to incorporate changes following March / April 2002 consultation. |

This Balancing Principles Statement has been developed and approved by the Authority/Director to assist BSC participants in understanding our actions in achieving the efficient, economic and co-ordinated operation of the transmission system. This Balancing Principles Statement may only be modified in accordance with the processes set out in Special Condition AA4 . We will review this Balancing Principles Statement, provide the Authority/Director with relevant information in relation to such review and provide the Authority/Director with the relevant reports and statements in accordance with the relevant provisions of Special Condition AA4 of the Transmission Licence.

In the event that it is necessary to modify this Balancing Principles Statement in advance of us issuing the annual updated version of the document, then this will be done by issuing a supplement to the Balancing Principles Statement.

The latest version of this document is available, together with the relevant change marked version (if any), electronically from the National Grid Website;
http://www.nationalgridinfo.co.uk/balancing/mn_transmission.html
Alternatively a copy may be requested from the Strategy and Development Manager, Operations and Trading, The National Grid Company plc, Kirby Corner Road, Coventry, CV4 8JY.

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# PART A: INTRODUCTION

## 1. Purpose of Document

This document is the Balancing Principles Statement, which The National Grid Company plc is required to establish in accordance with Special Condition AA4of the Transmission Licence. The purpose of this Balancing Principles Statement is to define the broad principles and criteria (the Balancing Principles) by which we will determine, at different times and in different circumstances, which Balancing Services we will use to assist in the operation of the transmission system (and/or to assist in doing so efficiently and economically), and when we would resort to measures not involving the use of Balancing Services.

This Balancing Principles Statement is designed to indicate the broad framework against which we will make balancing action decisions.

Part B sets out a number of general principles relating to the development and application of this Balancing Principles Statement and Part C describes the broad principles by which we will utilise balancing measures. Part D describes the broad principles by which we undertake both the management of transmission constraints and response/reserve services and Part E sets out the processes that we will normally undertake at the day ahead and on the day to achieve system balance. Part F summarises our operational security standards that effectively define the requirements for balancing measures. In Part H we have catalogued the number of occurrences of Emergency Actions, Involuntary Reductions and other significant events over recent years.

In the event that it is necessary to modify this Balancing Principles Statement in advance of us issuing the annual updated version of the document, then this will be done by issuing a supplement to the Balancing Principles Statement.

This Balancing Principles Statement has been developed and approved by the Authority/Director to assist BSC participants in understanding our actions in achieving the efficient, economic and co-ordinated operation of the transmission system. This Balancing Principles Statement may only be modified in accordance with the processes set out in Special Condition AA4. We will review this Balancing Principles Statement, provide the Authority/Director with relevant information in relation to such review and provide the Authority/Director the relevant reports and statements in accordance with the relevant provisions of Special Condition AA4 of the Transmission Licence.

This Balancing Principles Statement makes reference to a number of provisions contained in the Grid Code and Balancing and Settlement Code. In the event that any of the relevant provisions in the Grid Code or Balancing and Settlement Code are amended it may become necessary for us to seek to modify the Balancing Principles Statement in order that it remains consistent with the Grid Code and/or Balancing and Settlement Code.

In any event where our statutory obligations or the provisions of the Grid Code are considered inconsistent with any part of this Balancing Principles Statement, then the relevant statutory obligation and/or Grid Code provisions will take precedence.

Unless defined in this Balancing Principles Statement, terms used herein shall have the same meanings given to them in the Transmission Licence, the Grid Code and/or the Balancing and Settlement Code as the case may be.

Copies of this Balancing Principles Statement are available from The National Grid Company plc upon request. The most recent edition (and any archived editions) will be available from NGC's website http://www.nationalgridinfo.co.uk/balancing/mn_transmission.html.

# PART B: GENERAL PRINCIPLES

## 1 Licence Duties

This Balancing Principles Statement is written to be consistent with and to satisfy our licence obligation to "operate the Licensee's Transmission System in an efficient, economic and co-ordinated manner" and our duty under the Transmission Licence not to discriminate in our procurement or use of Balancing Services.

NGC will normally operate in accordance with the Balancing Principles Statement and compliance will be measured by two processes:

(i) Providing an annual report to the Director/Authority on the manner in which and the extent to which we have complied with the Balancing Principles Statement and whether any modifications should be made to the Balancing Principles Statement to reflect more closely our practice.

(ii) In addition we will be subject to an external audit to determine the extent to which we have, in using Balancing Services, complied with the Balancing Principles Statement. The audit statement will be made available to the Director/Authority in accordance with the Transmission Licence.

Additionally we shall, if directed by the Director/Authority, and in any event at least once a year, review the Balancing Principles Statement in consultation with BSC Parties and other interested parties likely to be affected by the Balancing Principles Statement.

## 2 Other Compliance Reporting

In addition to our licence duties we shall also provide a report to the Director/Authority, either when requested, or where we become aware of any circumstances of significant non-compliance, in our use of Balancing Services.

The report will summarise the incident together with an explanation of the circumstances leading to the deviation from this Balancing Principles Statement. We shall endeavour to provide such reports to the Director/Authority within 28 days of the request being made. Furthermore such reports shall be made available to the industry (via the Ofgem website).

## 3 Information Sources

We will determine what balancing measures will be employed by taking account of BM Unit data (made available on the Balancing Mechanism Reporting System (BMRS)) from participants, our forecast of 'NGC Demand' (BC1 of the Grid Code details the release of this information on the BMRS), the Transmission Outage Plan (our co-ordinated schedule of transmission plant outages, details of which are made available to relevant generators and Network Operators under OC2 of the Grid Code), actual system conditions (including weather conditions) and any other relevant data as defined in BC 1.4.2 (F) of the Grid Code).

## 4 Balancing Measures

The balancing measures available to us constitute both Balancing Services and other actions defined in the Grid Code (e.g. bid-offer

acceptances as per BC 2.7 and emergency instructions as detailed in section 4 below) required for the maintenance of system security.

The Transmission Licence defines Balancing Services as:

"(i) Ancillary Services

(ii) offers and bids made in the Balancing Mechanism; and

(iii) other services[1] available to the Licensee which serve to assist the Licensee in operating the Licensee's Transmission System in accordance with the Act or the Conditions and/or in doing so efficiently and economically".

## 5 Emergency Instructions

In certain circumstances it will be necessary, in order to preserve the integrity of our transmission system and any synchronously connected external system, for us to issue 'Emergency Instructions'. In such circumstances it may be necessary to depart from normal Balancing Mechanism (BM) operation in accordance with BC2.9 of the Grid Code. Examples of such circumstances that may require the issue of Emergency Instructions include:

### (a) Events

Events on our transmission system or the system of another user that leads or could potentially lead to insecure system operation and for which insufficient relevant bid-offers are available to restore system security. The Grid Code defines an 'Event' as:

> *'An unscheduled or unplanned (although it may be anticipated) occurrence on, or relating to, a **System** (including **Embedded Power Stations)** including, without limiting that general description, faults, incidents and breakdowns and adverse weather conditions being experienced'.*

[1] As defined in the Procurement Guidelines Part B Section 1

(b) **Demand Control** (detailed in OC6.5 to OC6.8)

Operating Code No. 6 (OC6) of the Grid Code is concerned with the provisions to be made by Network Operators, and in relation to Non-Embedded Customers by us, to permit the reduction of demand in the event of insufficient active power generation being available to meet demand, or in the event of breakdown or operating problems (such as in respect of system frequency, system voltage levels or system thermal overloads) on any part of our transmission system.

(c) **System and Localised Negative Reserve Active Power Margin** (detailed in BC2.9.4 of the Grid Code).

BC2.9.4 details the actions that we can undertake in ensuring that:

- the sum of synchronised gensets at all times are capable of reducing output sufficient to offset the loss of the largest secured demand on the system and
- synchronised gensets at all times are capable of reducing output to allow transfers to and from system constraint groups to be contained within the required limits.

In both cases this action must be sustainable.

**System Negative Reserve Active Power Margin**

It should be noted that if the System Negative Reserve Active Power Margin is not met then the resulting high frequency following the loss of the largest secured demand would not be abated.

Where we are unable to satisfy the required System NRAPM we will select (and instruct) Gensets for De-synchronising on the basis of Bid-Offer Data submitted to us.

**Localised Negative Reserve Active Power Margin**

If Localised Negative Reserve Active Power Margins are not maintained then it may not be possible to alleviate incidences of thermal overloading, system instability and voltage problems following transmission system faults.

In the case of Localised NRAPM we will select and instruct Gensets for De-synchronising on the basis of Bid-Offer Data submitted to us and their effectiveness in restoring the Localised Negative Reserve Active Power Margin to the required level.

In the event that we are unable to differentiate between Gensets according to Bid-Offer Data and/or their effectiveness in **restoring** any Localised Negative Reserve Active Power Margin, we will, where time permits, select gensets taking into account their:

- effect on power flows (resulting in the minimisation of transmission losses) – Gensets that would lead to the greatest reduction in transmission losses being selected first.
- Reserve/Response capability - Gensets with a lower response/reserve capability being selected in preference to Gensets with a higher capability (if instructing off);
- Reactive Power contribution - Gensets with a lower reactive power capability being selected in preference to Gensets with a higher capability;
- Dynamic Parameters – Gensets with more flexible dynamic parameters being selected in preference to those with less flexible parameters;

(d) **Black Start** (Detailed in OC9 of the Grid Code)

The need to invoke the Black Start process or the Re-Synchronisation of De-Synchronised Island process in accordance with OC9.

(e) **Frequency Sensitivity** (Detailed in BC2.9.5 of the Grid Code)

The need to maintain adequate frequency sensitive Generating Units in accordance with BC2.9.5.

(f) **Communication Failure**

Where unplanned outages of the electronic data communication facilities or NGC's associated computing facilities has occurred preventing normal Balancing Mechanism operation.

Where we identify the requirement to issue Emergency Instructions, and time permits, we will do so with due regard to the following principles:

(a) we will instruct those BM Units that are most effective in relieving the system problem;

(b) where BM Units have a similar level of effectiveness in relieving the system problem we will select on the basis of submitted Bid-Offer Data;

(c) where it is not possible to differentiate between the effectiveness or cost of BM Units we will instruct on the basis of:

- effect on power flows (resulting in the minimisation of transmission losses) – BM Units that would lead to the greatest reduction in transmission losses being instructed first.

- Reserve/Response capability – BM Units with a lower response/reserve capability being instructed in preference to Gensets with a higher capability;
- Reactive Power contribution – BM Units with a lower reactive power capability being instructed in preference to BM Units with a higher capability.

(d) where several BM Units have been instructed in response to an incident we will restore those units, where dynamic parameters and system conditions allow, in the reverse order of their instruction.

In the case of a BM Unit, Emergency Instructions may include an instruction for the BM Unit to operate in a way that is not consistent with the dynamic parameters, QPNs and/or export and import limits. In all cases (with the exception of the need to invoke the Black Start process or the Re-Synchronisation of De-Synchronised Island process in accordance with OC9 of the Grid Code) where we have issued an Emergency Instruction to a BM Participant and a valid and relevant bid or offer has been submitted, then we shall log a Bid-Offer Acceptance.

## 6 Involuntary Reductions

Under certain, mainly exceptional, circumstances we may need to take actions that will involve the involuntary reduction of generation or demand before all valid and **relevant** Balancing Mechanism offers have been accepted. Relevant Balancing Mechanism offers are defined as those being located in the correct geographic location and/or having the required dynamic parameters to resolve the system problem in question. Reasons for such actions include:

(i) where the call off of available offers would lead to an erosion of the system response holding below the required level. (It should

be noted that an instantaneous generation loss occurring at a time of depleted response holding could lead to a frequency deviation outside of statutory limits. In the extreme case the system frequency could fall below the trigger point for automatic low frequency demand disconnection – a minimum level of 6% of total system demand)

(ii) where automatic curtailment measures have been initiated in response to an incident

(iii) where the acceptance of relevant offers would lead to the depletion of reactive reserves below the required levels

(iv) where communication problems preclude the instruction of relevant bid/offers

Involuntary Reductions can arise either through our instruction (either manually or automatically) or following a system fault. Where we identify the requirement to call involuntary reductions, and time permits, we will do so with due regard to the following principles:

(a) we will instruct Network Operators whose demand is most effective in relieving the system problem;

(b) we will instruct those BM Units that are most effective in relieving the system problem;

(c) where it is not possible to differentiate between the effectiveness of Network Operators' demand (or BM Units) we will instruct those that will lead to the greatest reduction in transmission losses; and

(d) where several Network Operators (or BM Units) have been instructed in response to an incident we will instruct the

restoration of demand (or BM Units), where dynamic parameters and system conditions allow, in the reverse order of their instruction.

## PART C: PRINCIPLES UNDERLYING BALANCING MEASURES

1 We shall be responsible for making a forecast of 'National Demand' and 'NGC Demand' (as defined in the Grid Code) and the periodic release of these forecasts to the Balancing Mechanism Reporting Agent (BMRA) in accordance with the timetable specified in the BC1, Appendix 2 of the Grid Code. This data is published by the BMRA in accordance with section Q, Sub Section 6 of the Balancing and Settlement Code.

2 Having regard to information provided to us by BSC Parties (including their forecast levels of electricity demand) and to the requirements of the licensed transmission system security standards, we shall undertake operational planning for the timescales year ahead to day ahead:-

(a) for the matching of generation output (including, if achievable, a reserve of BM Units to provide a security margin sufficient to maintain an acceptable level of short term supply security) with forecast demand after taking into account:

(i) BM Unit availability, flexibility, prices and submitted dynamics;
(ii) transmission system capability;
(iii) electricity delivered to the transmission system from generation which is not required to submit Physical Notification (PN) data; and
(iv) any other relevant information.

(b) to enable maintenance on parts of the transmission system.

3 We will seek to comply with the above principles in deploying all available balancing measures in order to maintain system security at all times.

4 We will achieve balancing measures through the:

(i) acceptance of bids and offers submitted by generation and demand to the Balancing Mechanism;
(ii) call off of ancillary service contracts;
(iii) call off of other services which serve to assist us in operating the transmission system (including, for the avoidance of doubt, services from external system operators); and
(iv) instruction of Emergency Actions and other Involuntary Reductions.

In specific circumstances we will provide services to external system operators via System-to-System Services. On these occasions it is expected that we will procure Balancing Services to effect this service provision.

5 We shall call off balancing measures defined in 4(i), 4(ii) and 4(iii) in a cost order to maintain system balance. Under certain circumstances however this may not be possible. These circumstances include:

(i) urgent contingency action to restore operational standards on the transmission system;
(ii) technical constraints on the transmission system;
(iii) the observed and declared dynamic operating characteristics of available generation and demand Balancing Services;
(iv) other matters (such as those detailed in BC2.9) provided for in the Grid Code;
(v) failure of communication links; and
(vi) Services provided on Interconnector BM Units that could be operationally unacceptable to NGC, or commercially /

operationally to the External Interconnected System Operator (EISO).

Once the problem in (i) to (vi) above has been contained, steps shall be taken to progressively return to a normal cost order.

6 Treatment of BM Units Disconnected by Transmission System Faults

Rarely, following transmission system faults (see Part H), BM Units may become instantaneously disconnected from the transmission system. Under such circumstances following the fault and prior to reconnection we would only issue a bid/offer acceptance to the affected BM Unit if the trade provides immediate assistance to us in controlling the transmission system.

Following a transmission system fault which has caused disconnection, a BM Unit can only assist us in balancing the transmission system when:

- it is available to reconnect and return to its expected operating position in accordance with its submitted (or resubmitted) dynamics; and
- it can be reconnected to any part of the synchronised transmission system.

Under such circumstances a bid/offer acceptance may be issued to the BM Unit to delay the return to its expected operating position if the trade assists us in system balancing.

For the avoidance of doubt, in circumstances other than those described above, where a BM Unit submits a Physical Notification to connect to the transmission system, NGC will issue a Bid-Offer Acceptance (or Emergency Instruction) within Balancing Mechanism timescales if it wishes to change the proposed time of connection of the BM Unit.

7 Arbitrage Trades

Only if such opportunities arise in relation to performing our balancing obligations and where an economic advantage would be gained with

no detrimental impact on system security would we undertake direct arbitrage trades within the Balancing Mechanism.

## 8 Beyond the Wall Actions

On occasion, National Grid will issue BOAs that extend to the end of the current BM window ('the wall'). On these occasions, National Grid will issue BOAs to return the BMU to its PN level in line with submitted dynamics (subject to no change in the prevailing BMU data). Further details of these circumstances are provided below.

National Grid continually assess the various factors that affect system conditions. This may lead to a requirement for a continuing increase or decrease in BMU output, from it's PN level, some time in the future that extends beyond the end of the current Balancing Mechanism window ('beyond the wall'). In order to reflect the relevant BMU dynamics, National Grid may be required to issue a further BOA "beyond the wall". System Conditions and special circumstances will also be taken account of in these situations.

Beyond the wall actions will be taken on a BMU specific basis, subject to the following information:

- indicative Physical Notifications
- dynamic data
- indicative Bid/Offer prices
- export and import limits
- location of BMU
- reactive capability
- frequency response performance
- system conditions
- predicted weather conditions
- ancillary service contracts

The intention to issue a further BOA “beyond the wall” will be communicated to the relevant BMU Transaction Point in cases where a current BOA has been issued that extends up to the end of the current Balancing Mechanism window (‘the wall’).

The intention to issue a BOA “beyond the wall” will be based on the submitted dynamic and price data for all anticipated BOA timescales. It is assumed that all dynamics and prices remain as submitted for all anticipated BOA timescales. For the avoidance of doubt, if the intention is to extend a BOA beyond the wall, indicative prices, dynamics and PN for periods beyond the wall must not change from those that were used in assessing the requirement for the BOA.

This intention to issue a BOA “beyond the wall” will be translated into an actual BOA after the start of each applicable gate closure period. Prior to the BOA being issued, all BMU data will be checked against that used during the initial assessment. Any material changes made from the data used during the initial assessment will lead to a review of the requirement.

**Cancelling of BOAs that extend beyond the wall**

The unwinding of BOAs that are issued beyond the wall will be in line with that of standard Bid/Offer acceptances.

BOAs that are issued beyond the wall will be cancelled by returning the BMU to its PN in line with submitted dynamics taking into consideration any applicable price changes.

## 9 Pre Gate Closure BMU Transactions

This section explains the criteria used to select a BM Unit for a Pre Gate Closure Transaction. The reasons for requiring such a transaction are covered in the Procurement Guidelines Part B: Paragraph 4.

We, in the maintenance of efficient, economic and secure system operation, continually assess our requirements for within gate Balancing Services against our forecasts and participants' latest notified PNs.

These assessments may lead to a requirement for us to enter into an agreement to procure balancing services ahead of the Balancing Window. Such pre gate requirements are referred to as Pre Gate Closure BMU Transactions (PGB Transactions).

PGB Transactions will be taken on a BMU specific basis and the following criteria will be used in the selection of BMUs that are potentially best able to meet the requirements:

- indicative Physical Notifications
- relevant BMU dynamics
- specialised BMU information e.g. dynamic parameters that differ from those submitted
- transmission constraints imposed on the system
- location of BMU
- reactive capability
- frequency response performance
- previous PGB Transaction performance (this will only be a factor where reliability is of significant importance and when a decision has to be made close to gate closure)

- associated ancillary service contracts

Using the above information, the most suitable BMUs that fit the requirements will be selected and contacted by telephone. An outline of the profile required will be communicated over the telephone to the selected BMUs. We will invite offers from the selected BMUs detailing the profile and price.

If system circumstances limit the timescales required for identifying and agreeing a PGB Transaction then it may be necessary to restrict the number of BMUs that we contact (for example a PGB Transaction required close to Gate Closure). In this case, the BMUs will be prioritised based on National Grid's assessment of the BMUs that are likely to meet the criteria with due regard to the requirements in line with the Transmission License obligations not to discriminate. This assessment may include anticipated prices (informed by historic Bid/Offer and PGB Transaction prices) as a prioritisation factor.

Once all offers have been received, they will be assessed against the following criteria:

- Cost ; and
- Which offer best meets the requirements based on the criteria set out above and the requirements described in the Procurement Guidelines (Part B, Section 4).

The successful BMU(s) will be contacted by telephone and the transaction formally agreed. We will expect to receive a modified PN in line with the transaction details within 15 minutes of the transaction.

We currently envisage that in the future requirements will be posted onto a screen based exchange system thereby allowing market

participants to offer the service in an open and transparent manner and have access to relevant information.

We believe that detailed market design will take place when we have some operational experience of operating within one hour gate closure. We have therefore initiated discussions with current power exchange providers and will be discussing potential market designs with market participants.

In taking forward this market design the key issues we will seek to address are as follows:

- To provide an improved mechanism (to that already in place) for indicating to the market, National Grid's requirements for these services;
- To provide a more timely indication of all offers made available to National Grid whether accepted or not; and
- To take into account experience of operating the market and if appropriate increase the flexibility of the contract forms.

# PART D: TRANSMISSION CONSTRAINT MANAGEMENT AND RESPONSE/RESERVE PRINCIPLES

The broad principles that we will normally employ for the management of transmission constraints and response/reserve holdings are detailed below. It should be noted that transmission constraint management involves an iterative process over all planning timescales with, where possible, continued optimisation of the system as updates to relevant information are received.

It should be further noted that an indication of the extent to which the transmission system is constrained can be gained from the margin information that we are required to release under OC2 and BC1 of the Grid Code.

## 1 Transmission Constraint Management Principles

- Outage planning for the period year ahead to day ahead will be undertaken. In developing the outage plan for the transmission system co-ordination is required with other Network Operators (where Network Operators is as defined in the Grid Code).

- We will endeavour to place outages coincident with relevant generation outages in order to minimise constraint costs.

- Security analysis studies are undertaken as appropriate to confirm system security of the total transmission system and identify constraints.

- Forecasts of constraint costs are made and the outage plan re-optimised to minimise these where possible.

- Significant changes to forecast availability of BM Units and/or the transmission system may trigger a reassessment of the outage plan and where possible the outage plan will be re-optimised.

- We may negotiate Balancing Services contracts to manage the financial risks associated with potential high cost outages.

- In calculating constraints we will take account of any pre and post fault actions available in order to minimise restrictions of generation capacity.

- In resolving constraints we will call off Balancing Services on a cost basis (with due regard to the criteria set out in Part C, paragraph 5). Where services can not be differentiated on cost or flexibility the service that delivers the greatest reduction in transmission losses will be called.

- During periods of system difficulties (for example severe weather conditions) we may modify constraint limits in accordance with level of system risk. In so doing consideration of the following criteria will be given:

    (i) the likely duration of the system difficulties;
    (ii) the likely increase in probability of system faults arising from the system difficulties; and
    (iii) the impact on system security of faults deemed likely to arise as a result of the system difficulties.

## 2 Constraint Management Processes

Transmission constraints are calculated and optimised in the following timescales: year ahead, 13 week ahead, 2 week ahead, day ahead and in the pre Gate Closure control phase. Furthermore constraints are continually monitored and optimised in real time.

## 2.1 Year Ahead

Throughout the year ahead planning process, NGC, generators, and other Network Operators exchange data relating to transmission system and generation outages for the following year. The content and timing of these data flows are currently specified under the OC 2 of the Grid Code.

Using a combination of this data and the NGC estimated generation merit order, NGC builds its transmission outage plan for the following plan year. In building the plan, the following principles are applied:

(i) The necessary NGC maintenance and construction programme must be accommodated.
(ii) System security must be achievable at all times.
(iii) Transmission constraints must be minimised.

Achieving these principles requires extensive security and economic studies of the planned transmission system.

Where this analysis identifies that some of the above principles cannot be met due to conflicting outage requirements, discussions take place between the parties involved to resolve the issues. The method of resolving conflicting requirements is set out in OC2 of the Grid Code.

Progress towards achievement of a final transmission operating plan is formally communicated at regular intervals throughout the planning year to generators and other Network Operators. These updates are specified under OC2 of the Grid Code.

## 2.2 13 Week Ahead / 2 Week Ahead / Day Ahead

The following process is undertaken in each of the above timescales the objective being to ensure system security is achieved at minimum cost whilst meeting our system maintenance and construction requirements:

Step 1- Using our forecast of demand, BM Unit availability/running, BM Unit prices and the transmission outage plan, security analysis studies are undertaken. These studies involve the running of system analysis models that can determine system voltage, thermal and stability conditions.

Step 2 - From the output of these studies system security is assessed. If security can not be achieved then the outage plan will be reviewed and revised accordingly.

Step 3 - Transmission constraint boundaries will be identified and further studies will be undertaken to calculate the limiting power flows across these boundaries.

Step 4 - At the day ahead stage, following receipt of PN data warming contracts may be called where appropriate to maintain system security of the transmission system.

Step 5 - The forecast costs of these constraints are then calculated and where necessary and possible the transmission outage plan will be revised.

## 2.3 Control Phase – Pre Gate Closure

In light of actual system conditions and revisions to our day-ahead forecasts, further security analysis studies will be undertaken to assess our transmission constraint requirements. Our plant requirements will also be re-assessed and suitable units requested to synchronise or de-synchronise depending on the outcome of this assessment. This will usually take the form of a warming contract or in certain circumstances, as set out in the Procurement Guidelines, a PGB Transaction (see Part C Paragraph 9).

## 2.4 Control Phase – Real Time

System security will be continually monitored in real time through the use of 'on-line' security analysis studies based on actual system conditions. In light of these studies and actual BM Unit bidding, all transmission constraints will be continually reviewed and optimised to seek to ensure balancing costs are minimised.

# 3 Response/Reserve Holding Principles

The objectives of our response/reserve holding policy shall be to provide assurance, in so far as we are able, that reasonably foreseeable levels of generation failure, shortfall and demand forecast error do not cause us to invoke involuntary demand disconnection. In so doing we shall endeavour to adopt a response/reserve holding strategy that maintains the pre NETA level of short-term supply security.

Initially we will use pre-NETA supply security standards as a benchmark for our reserve and response policies. However we recognise that these policies may develop in the light of market circumstances and experience.

## 3.1 Response

Response is provided by sources that automatically react to frequency deviations and is required to manage instantaneous imbalances between generation and demand. There are three categories of response that we will contract for and these are detailed below:

(a) Primary Response

This is the automatic response to a decrease in system frequency which is increasingly effective with time over the period 0 to 10 seconds from the time of the frequency change (and fully available by the latter) and which must be sustainable for at least a further 20 seconds. In the event of a system infeed loss, primary response acts to contain the falling frequency.

(b) Secondary Response

This is the automatic response to a decrease in system frequency which is fully available 30 seconds from the time of the frequency change and sustainable for at least 30 minutes. In the event of a system infeed loss secondary response acts to restore the system frequency to operational limits.

(c) High Frequency Response

This is the automatic response (of reducing output from generation) to an increase in system frequency which is increasingly effective with time over the period 0 to 10 seconds from the time of the frequency change (and fully available by the latter) and which must be maintained (at no lesser reduction) thereafter.

The magnitude of the largest infeed set against the contribution of system inertia and reaction of demand to falling frequency will

determine the primary and secondary response requirement. Generally speaking, as more generation is synchronised to meet increased demand the system has more stored energy in rotating machines meaning less response is required to contain the same generation loss. Similarly, as demand increases, the absolute reduction in demand in response to falling frequency increases.

Similarly the high frequency response requirement will be determined by the magnitude of the largest secured demand and the level of system inertia.

Response can be delivered by both dynamic (or continuous) and non-dynamic (or occasional) sources. Dynamic response is delivered continuously as system frequency deviates from target and is provided by part loaded generation. Non-dynamic response is delivered only when the system frequency reaches a set trigger point and is predominantly provided by contracted demand armed with low frequency relays.

In order that frequency can be contained within operational limits, and thereby minimise the risk of frequency falling outside of statutory limits, a minimum dynamic response requirement exists. The actual level of this minimum dynamic requirement is determined by our operational requirement to maintain the standard deviation of 5 minute spot frequency to 0.07Hz.

## 3.2 Reserve

Reserve is used to cover longer term imbalance between supply and demand caused by demand forecast error, plant failure, and the uncertainty associated with periods of rapid demand change. Reserve is also used to restore system frequency and response capability following a short-term loss. We have four categories for system reserve which are detailed below:

(a) Contingency Reserve

This will be delivered primarily through 'warming contracts' to ensure sufficient generation is available at gate-closure to meet system demand, system security and our response and reserve holding requirements. It effectively covers for longer-term (i.e. pre gate closure) plant losses and demand forecasting errors.

The initial assessment for contingency requirements will be made at the day ahead and revised throughout the control phase as certainty in both demand forecasting and generation availability increases.

The requirements for contingency reserve will be based on longer-term plant loss statistics, demand forecast error and demand BM Unit offers.

(b) Regulating Reserve

Regulating reserve is required to cover for short-term (i.e. post gate closure) generation losses and demand forecasting error and will be carried on part loaded synchronised generation or demand BM units.

It is envisaged that initially this service will be provided by BM Units that are voluntarily submitting suitable bids/offers to the Balancing Mechanism although, if insufficient volumes of regulating reserve can be obtained in this way or it is economic to do so, ancillary service contracts may be put in place for the provision of this reserve service.

(c) Standing Reserve

Standing reserve is carried by contracted short notice generation (with a delivery time of less than 20 minutes) and contracted demand that can be shut down within 20 minutes.

As with regulating reserve, it is required to cover for post gate closure plant loss and demand forecasting errors.

Regulating and Standing reserves make up the total requirement dictated by post gate closure plant loss statistics and demand forecasting errors. The actual split between standing and regulating reserves will be dictated by the economics of the provision of these services from the available sources.

(d) Fast Reserves

Fast reserve is a subset of regulating/standing reserve and is required for the maintenance of system frequency within operational limits. It is provided primarily by contracted generation that is capable of significantly increasing output within 2 to 5 minutes notice.

The volumes of fast reserves are determined by our operational standard to limit the number of frequency excursions outside operational limits (lasting greater than 10 seconds) below 1500 per annum.

## 3.3 Principles Relating to Response and Reserve Holding.

- We will calculate response and reserve holding levels based on the following criteria:
  (i) BM Unit loss statistics
  (ii) the largest generation infeed being covered
  (iii) the largest secured system demand
  (iv) demand forecast statistics
  (v) system characteristics such as inertia and load response
  (vi) judgement of levels of demand volatility/uncertainty
  (vii) judgement of levels of generation uncertainty

- We will allocate response and reserve holding with due regard to:
  (i) cost
  (ii) dynamics of delivery (as detailed in 3.1 and 3.2 above)
  (iii) transmission constraints

- We will not allocate response/reserve to constrained BM Units if the delivery of that response/reserve would result in violation of the constraint.

- During system difficulties (caused for example by severe weather conditions) we may strategically allocate response/reserve on a geographic basis to manage system risk. In so doing consideration will be given to the following criteria:
  (i) the likely duration of the system difficulties
  (ii) the parts of the system affected by the system difficulties
  (iii) the likely increase in probability of response/reserve holding being affected by the system difficulties

- At all times we will endeavour to maintain sufficient levels of response on the system in order that the loss of the largest generation infeed would not result in a violation of the security standards.

- Following an event that leads to the delivery of response we will, as soon as is practical, take action to regain the level of response holding on the system such that system security standards would not be violated following a further generation infeed loss. Such action includes the instructing of standing reserve such that responsive BM Units can be brought back to their respective response holding levels.

- We will seek to hold sufficient high frequency response on the system to ensure that security standards are not compromised should the largest secured demand on the system trip.

- In achieving the above we will seek to ensure that there is a suitable level of generation capable of reducing output on the system at all times.

# PART E: DAY AHEAD AND WITHIN DAY BALANCING

## 1. Day Ahead Balancing Process – Scheduling Phase

Step 1 - By 09:00 hours each day we will publish our day ahead demand forecast covering the period 05:00 hours day ahead to 05:00 hours day ahead + 1.

Step 2 - By 11:00 hours we will receive Physical Notification (PN) and other data from all BM Units covering the period 05:00 hours day ahead to 05:00 hours day ahead + 1 and default such data as is necessary.

Step 3 - Using the submitted PN data, demand forecast and planned transmission outage information we will undertake security analysis studies to verify system security (Part F refers).

Step 4 - For each half hour period from 05:00 hours day ahead to 05:00 hours day ahead + 1 the system BM Unit requirement (i.e. that required to meet system demand and system response/reserve levels) is calculated from the sum of forecast demand, scheduled reserve[2], contingency reserve and standing reserve (less that provided by contracted non BM Unit sources).

Step 5 - For each half hour period from 05:00 hours day ahead to 05:00 hours day ahead + 1 the sum of BM Units maximum export limits (MEL) is calculated based on the 11:00 hours PN submission.

[2] Scheduled reserve is the total amount of headroom required to meet the level of regulating reserve and frequency response allocated to synchronised BM Units.

Step 6 - The system plant margin for each half-hour period is then calculated by subtracting the identified BM Unit requirement from $\sum$ MEL (after accounting for BM Units likely to be restricted by constraints).

Step 7 - The system plant margin for each half-hour is therefore derived from:

($\sum$ MEL - $\sum$ Constrained Off BM Units) – BM Unit Requirement

Step 8 - If the system plant margin is negative then we will revisit the transmission outage plan and where possible make revisions in order to reduce the level of constrained off BM Units.

Step 9 - If the system plant margin remains negative we shall, dependant on the level and duration of the shortfall and the time period to the shortfall, issue the appropriate system warning to the market.

Step 10 - By 12:00 hours each day we will issue the total system plant margin data to the market for the period 05:00 hours day ahead to 05:00 hours day ahead + 1.

Step 11 - We will forecast constraint costs based on the submitted indicative PN (and other BM Unit) data and our estimation of Final Physical Notification (FPN) levels and bid-offer prices and volumes. Depending on the forecast levels of these costs we will give consideration to the cancellation/deferral of transmission system outages.

Step 12 - Where judged necessary we will seek to call off Balancing Services contracts (on a cost basis with due regard to the criteria set out in Part C, paragraph 5) to ensure, inter alia, that

BM Units required to maintain system security are available for selection in the Balancing Mechanism.

Step 13 - Following 11:00 hours we will continue to receive updated PNs from BM Units.

Step 14 - Using this updated data we will revise the national plant margin data and publish this together with zonal margin data by 16:00 hours.

## 2. Within Day Balancing Process – Control Phase

Step 1 - At defined times we will revise and release to the BMRA in accordance with 6.1.7 of Section Q of the Balancing and Settlement Code half-hourly averaged demand forecasts.

Step 2 - As participants become aware of changes to their physical position they will be expected to advise us of those changes.

Step 3 - At defined times, using the latest demand forecast, PN and other BM Unit data, the zonal and national margins will be reassessed and released to the BMRA in accordance with 6.1.7 of Section Q of the Balancing and Settlement Code.

Step 4 - Using the revised data we will undertake security analysis studies and reassess the requirements for the call off of Balancing Services contracts or Other Services such as PGB Transactions.

Step 5 - At gate closure the PN data will become FPN data and we will have received Bid/Offer prices and volumes for those BM Units wishing to actively participate in the Balancing Mechanism.

Step 6 - In the Balancing Mechanism, using the revised demand forecast and validated FPN and Bid/Offer data, we will seek to balance the system (on a minute by minute basis) through the purchase of Balancing Services on an economic basis taking into account:

(i) urgent contingency action to restore operational standards on the transmission system;

(ii) technical constraints imposed on the system from time to time;

(iii) the dynamic operating characteristics of available generation and demand balancing services;

(iv) where BOAs are expected to be issued for periods beyond the wall, those Bid/Offer prices associated with all BOA timescales, PNs and dynamics for the BMU;

(v) uncertainty in demand at timescales within the Balancing Mechanism window;

(vi) other matters provided for in the Grid Code; and

(vii) Services provided on Interconnector BM Units that could be operationally unacceptable to NGC, or commercially / operationally to the External Interconnected System Operator (EISO).

In extreme situations this may require the instruction of Emergency Instructions and/or Involuntary Reductions as defined in Part B Sections 3 and 4.

# PART F: SUMMARY OF OPERATIONAL SECURITY STANDARDS

## 1 Overview

We shall seek to economically maintain security on the transmission system such that for normal and outage conditions, for a **secured event** there shall not be:-

- a loss of supply,
- a violation of the **system frequency control standard**,
- a violation of the **system voltage control standard**,
- system instability,
- unacceptable overloading of apparatus.

Excluding the exceptions below a **secured event** is defined as the fault outage of:-

- a single circuit overhead line,
- a double circuit overhead line,
- a designated pair of single circuit overhead lines concurrently during the defined winter season,
- a single circuit cable,
- a section of busbars or mesh corner,
- a supergrid transformer,
- a reactive compensator,
- the most onerous single system infeed.

For demand groups with a net import of up to 1500MW a **secured event** is defined as the fault outage of:-

- a single circuit overhead line,
- a single circuit cable,
- a supergrid or grid transformer or reactor,

- the most onerous single system infeed.

### 1.1 Exceptions

The standards may be relaxed for connections for which a derogation (approved by the Director/Authority) from Condition 12 of the Transmission Licence is in force.

For demand groups with a net import of less than 300MW and under outage conditions then for a **secured event** a loss of supply is acceptable.

Loss of supply for a **secured event** is also acceptable under planned outage conditions subject to a restoration strategy agreed between the SO and the relevant party.

## 2 System Frequency Control Standard

We shall seek to economically purchase and schedule sufficient real energy reserve and response such that:

For a **significant event i.e.** any **secured event** which could result in sudden change between total mechanical power input and actual system demand which is in the range 300MW to 1000MW the system frequency shall not deviate by more than 0.5Hz and that for;
An **abnormal event i.e.** any **secured event** which could result in a sudden change between total mechanical power input and actual system demand which is in the range 1000MW to 1320MW the system frequency should not deviate by more than 0.8Hz.

***For either significant or abnormal events any frequency deviation below 49.5Hz should not persist for more than 60 seconds, and system frequency should return to between operational limits within 10 minutes. If necessary we shall achieve, in exceptional***

***circumstances, frequency control by demand control – as required by the British Grid Systems Agreement (BGSC 12) and as specified in OC6 of the Grid Code.***

## 3 Voltage Control Standard

Under normal system conditions we shall seek to purchase and economically schedule sufficient Mvar reserves in order to maintain steady state voltage levels such that:-

On the 400kV system each user connection site will normally remain within +/- 5% of the nominal value with a minimum/maximum range of +/-10% however voltages between +5% and +10% should not last longer than 15 minutes.

On the 275kV and 132kV system each user connection site will normally remain within +/- 10%.

Below 132kV the limits are +/- 6%.

In addition for any **secured event** we shall purchase and economically schedule sufficient Mvar reserves in order to limit voltage step change to:-

+/-6% **at the user connection site** after a **secured event**, relaxed to +/-12% for loss of a double circuit, busbar or mesh corner. This voltage step change relates to a period about 5 seconds after fault clearance. It must be possible for us to restore voltage at GSPs to 95% following automatic and manual action within 20 minutes.

+/- 3% **at the user connection site** for planned switch operations.

## PART G: EXCEPTIONS TO THE BALANCING PRINCIPLES STATEMENT

Infrequently circumstances may arise which require us to operate outside the principles detailed in this statement. Such circumstances are listed below:

(i) Black Start events (as detailed in OC9 of the Grid Code);

(ii) where parts of the transmission system have become islanded (as detailed in OC 9 of the Grid Code);

(iii) when emergency evacuation procedures have been invoked at our control centres or wide spread communication problems are experienced;

(iv) where circumstances exist where not to do so would prejudice the safe and secure operation of the transmission system or would be in breach of statutory obligations;

(v) where operational information indicates insufficient time is available to employ particular measures in accordance with the Statement if balancing is to be achieved; and

(vi) where the Statement has been shown to be inappropriate and the Balancing Principles Statement modification procedures have been implemented but not completed.

For parts (i) to (iii) above we would issue the appropriate system warning in accordance with the Grid Code and occurrences of any of the circumstances above would be reported in our annual statement of performance against the Balancing Principles.

# PART H: INCIDENCES OF EMERGENCY INSTRUCTIONS, INVOLUNTARY REDUCTIONS AND OTHER SIGNIFICANT EVENTS

| Event | 1997/1998 | 1998/1999 | 1999/2000 | 2000/2001 |
|---|---|---|---|---|
| Emergency Instructions note 1 | 0 | 0 | 0 | 0 |
| Involuntary Reductions note 2 | 0 | 0 | 0 | 0 |
| Generator Disconnection following a system fault | 5 | 0 | 0 | 2 |
| Black Starts | 0 | 0 | 0 | 0 |

Notes:

## 1 Emergency Instructions

The Grid Code has in place warning procedures, NGC System Warnings, which enable potential and actual system conditions or events to be communicated and assist the management of the system. Although these warnings have been used to notify of plant shortfalls no actual **Demand Reduction** has actually been instructed.

NGC has also issued NRAPMs to generators at periods of low demand to encourage redeclarations of inflexibility. This mechanism has led to redeclarations from generators, which has meant NGC has not needed to take emergency action and instruct inflexible generation to desynchronise.

## 2 Involuntary Reductions

Includes instructing of Customer Demand Reduction and automatic Low Frequency Demand Disconnection under OC6 of the Grid Code.