Balancing Principles Statement

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This Balancing Principles Statement has been developed and approved by the Authority to assist market participants in understanding our actions in achieving the efficient, economic and co-ordinated operation of the transmission system and ensuring the security of the system at all times. This Balancing Principles Statement may only be modified in accordance with the processes set out in Standard Condition C16 of National Grid Electricity System Operator Transmission Licence. When reviewing this Balancing Principles Statement, we will provide the Authority with relevant information in relation to such review and with the relevant reports and statements in accordance with the relevant provisions of Standard Condition C16 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 an additional review 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 ESO Website:
https://www.nationalgrideso.com/balancing-services/c16-statements-and-consultations

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PART A: INTRODUCTION

1. Purpose of Document

This document is the Balancing Principles Statement which National Grid Electricity System Operator Limited (NGESO) is required to establish in accordance with Standard Condition C16 of 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 efficient and economic operation of the transmission system, and also to define 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 within which we will carry out balancing measures. Part G explains exceptions to the Balancing Principles Statement, where circumstances may arise which require us to operate outside the principles detailed in previous sections.

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 by NGESO and approved by the Authority, to assist market 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 Standard Condition C16 of the Electricity Transmission Licence. We will review this Balancing Principles Statement, provide the Authority with relevant information in relation to such review and provide the Authority the relevant reports and statements in accordance with the relevant provisions of Standard Condition C16 of the Electricity 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 Electricity 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 NGESO upon request. The most recent edition (and any archived editions) will be available from National Grid ESO's website

https://www.nationalgrideso.com/balancing-services/c16-statements-and-consultations

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 Electricity Transmission Licence not to discriminate in our procurement or use of Balancing Services.

NGESO 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 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) 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 Authority in accordance with the Electricity Transmission Licence.

Additionally, we shall, if directed by the 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 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 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 Balancing Mechanism Unit (BMU) data (made available on the Balancing Mechanism Reporting System (BMRS) from participants), our forecast of GB National Demand and GB Transmission System 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 ~~BC1~~BC1.4.2 (f) of the Grid Code.

4 Balancing Measures

The balancing measures available to us constitute Balancing Services. The Balancing Services are defined in Standard Condition C1 of NGESO's Transmission Licence. A detailed explanation of these Balancing Services is provided in the Procurement Guidelines.

5 Emergency Instructions

In certain circumstances it will be necessary, in order to preserve the integrity of the GB 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 BM operation in accordance with BC2.9 of the Grid Code.

General Principles for Issuing Emergency Instructions

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 BMUs that are most effective in relieving the system problem;

(b) Where BMUs 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 BMUs we will instruct on the basis of:

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

(d) where several BMUs 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 BMU, Emergency Instructions may include an instruction for the BMU 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, details will be posted on the BMRS and the Emergency Instruction Acceptance Data will be agreed post event.

Examples of such circumstances that may require the issue of Emergency Instructions include:

(a) **Events**

Events on the GB Transmission System or the System of another user that lead 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'.*

(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 the GB 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 BMUs at all times are capable of reducing output sufficient to offset the loss of the largest secured demand on the system and
- synchronised BMUs 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 (NRAPM) 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) BMUs for De-synchronising on the basis of Bid-Offer Data submitted to us.

Localised Negative Reserve Active Power Margin

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

We will select and instruct BMUs for De-synchronising on the basis of Bid-Offer Data submitted to us and their effectiveness in restoring the Localised NRAPM to the required level.

- In the event that we are unable to differentiate between BMUs according to Bid-Offer Data and/or their effectiveness in restoring any Localised NRAPM, we will, where time permits, select BMUs in accordance with the General Principles described above.

(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) **Maximum Generation Service**

The Maximum Generation Service is no longer in active procurement, however the service is optional and only carries a utilisation payment and therefore will continue to be considered as part of our balancing approach. The need to request the Maximum Generation Service would normally be in order to maintain system security in the event that all valid and feasible Bids and Offers have been accepted in the BM. Where possible, the request for Maximum Generation Service will take place prior to the instruction of any measures related to Demand Control under OC6 1.2.(c), (d) or (e) of the Grid Code. Information relating to the instruction of the Maximum Generation Service will be published on the BMRS as soon as reasonably practicable.

The Maximum Generation Service will only be instructed where a BMU has been instructed to, or is generating at, its Maximum Export Limit.

For the avoidance of doubt, valid and feasible Bid and Offers are those Bids and Offers which facilitate the delivery of energy within the relevant Settlement Period. Under certain exceptional circumstances, it may be necessary to invoke the Maximum Generation Service before all valid and feasible Bids and Offers have been accepted. These circumstances may include:

(i) where the call off of available Offers would lead to an erosion of the system reserve for response below the required level;

(ii) where the acceptance of relevant Offers would lead to the depletion of reactive reserves below the required levels; and

(iii) where no other plant with suitable dynamics is available

For the avoidance of doubt, the decision to instruct the Maximum Generation Service will be taken based upon the prevailing system conditions on the transmission system. The price of other available actions offered through the BM will have no bearing upon the decision to instruct Maximum Generation Service.

(f) **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.

(g) **Communication Failure**

Where unplanned outages of the electronic data communication facilities or NGET associated computing facilities has occurred preventing normal BM operation.

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 BM Bid-Offers have been accepted. Relevant BM Bid-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 calloff, 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 BMUs 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 BMUs) we will instruct those that will lead to the greatest reduction in transmission losses; and

(d) where several Network Operators (or BMUs) have been instructed in response to an incident we will instruct the restoration of demand (or BMUs), 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 'GB National Demand' and 'GB Transmission System 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 6.1 of the Balancing and Settlement Code.

2 Having regard to information provided to us by market participants (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 BMUs to provide a security margin sufficient to maintain an acceptable level of short term supply security) with forecast demand after taking into account:

(i) BMUs 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;
(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 BM);
(ii) call off of Ancillary Service contracts;
(iii) call off of other services which serve to assist us in operating the transmission system;

(iv) call off of emergency assistance/instructions associated with external System Operators; and

(v) instruction of Emergency Instructions and other Involuntary Reductions.

(vi) trades to reduce or increase flows across Interconnectors.

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 BMUs that could be operationally unacceptable to NGESO, 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 BMUs Disconnected by Transmission System Faults

Rarely, following transmission system faults, BMUs may become instantaneously disconnected from the transmission system. Under such circumstances following the fault and prior to reconnection we would only issue a BOA to the affected BMUs if the trade provides immediate assistance to us in controlling the transmission system.

Following a transmission system fault which has caused disconnection, a BMU 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 BOA may be issued to the BMU 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 BMU submits a PN to connect to the transmission system, NGESO issue a BOA (or Emergency Instruction) within BM timescales if it wishes to change the proposed time of connection of the BMU.

7 Arbitrage Trades

Opportunities for arbitrage trades may occur when the bid and offer prices of different units overlap. By taking a bid and offer simultaneously there is an economic benefit with no associated change in the overall energy position (e.g. turning down a unit and being paid £46/MWh whilst simultaneously turning up another unit paying only £44/MWh).

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 BM.

8 Beyond the Wall Actions

On occasion, NGESO will issue BOAs that extend to the end of the current BM window (‘the wall’). On these occasions, NGESO 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.

NGESO continually assesses the various factors that affect system conditions. This may lead to a requirement for a continuing increase or decrease in BMU output, from its PN level, sometime in the future that extends beyond the end of the current BM window ('beyond the wall'). In order to reflect the relevant BMU dynamics, NGESO 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 PNs
- 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 Control Point in cases where a current BOA has been issued that extends up to the end of the current BM 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.

9 BOAs returning BMUs to PN (for BMUs that have been BOAd up to the wall)

Where appropriate, BMUs that have been BOAd up to the wall will be returned to PN, when the BM window has been extended by the subsequent issue of BOAs in line with submitted dynamics, provided parameters and prices have not changed as described in Section 8.

10 Net Transfer Capacity (NTC)

The principles of use of the non-frequency balancing service, Net Transfer Capacity ("NTC") are set out within the GB Commercial Compensation Methodology with the intent (and in line with the C28 derogation granted to allow procurement of NTC via non-market-based mechanisms) that NTC will not be used where feasible economic alternative actions are available to resolve the system issue.

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 BMU 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~~ enter into 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 cannot 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

In the Year Ahead timescale, transmission constraints are minimised through careful planning of transmission outages. Within the current year, transmission constraints are calculated and optimised as necessary from 9 weeks ahead, down to day ahead timescales 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, NGESO, 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 NGESO estimated generation merit order, NGESO builds its transmission outage plan for the following plan year. In building the plan, the following principles are applied:

(i) The necessary NGET 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 9 Weeks Ahead down to Day Ahead

The following process is undertaken across 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, BMU availability/running, BMU 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 cannot 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, the BM Start-up service 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 BM Start-up service or day ahead trades. Additionally, units may be armed to intertripping schemes as an alternative to redespatching units to manage constraints.

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 BMU bidding, all transmission constraints will be continually reviewed and optimised to seek to ensure balancing costs are minimised.

2.5 New localised constraint management services – Regional Development Program

As part of the Regional Development Programme, two new services are scheduled to go live in 2023: Generation Export Management (GEMS) for SW Scotland and MW-Dispatch for Southern England (initially SW England). These represent innovative ways of operating the network and managing transmission constraints in a coordinated whole system manner, with DNOs. These ESO services will integrate with DNO automatic network (constraint) management systems with further enhanced coordination of DNO & ESO planning and real-time operational activities. All new connecting parties in these otherwise congested areas, are obligated to participate in the relevant commercial curtailment scheme. Already connected parties may choose to participate in the scheme if they are in the impacted network area. Non-BMUs will be able to submit a curtailment price £/MWh that will apply per unit for each operational day.

The MW Dispatch service will be utilised whenever there is congestion in the transmission system in SW England. DER (Distributed Energy Resources) third party providers connected to the DNO network and generating, which may be causing network issues or impacting transmission constraints in this area (SW England), will be considered alongside existing BM participants for system curtailment purposes. The assessment will be based upon both system needs and economic efficiency.

The GEMS automatic constraint management service will be utilised whenever there are active constraints in SW Scotland. A new automatic system will monitor network boundaries and curtail in merit order from the list of participating, MW-exporting parties impacting that boundary. The initial service will be limited to transmission connected parties. This will be extended in the coming years to include distribution connected parties.

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, demand forecast error and secured generation or demand loss do not cause unacceptable frequency conditions or minimise the need to invoke involuntary demand disconnection. In so doing we shall endeavour to adopt a response/reserve holding strategy that maintains the prevailing level of short-term supply security.

Initially we will use the prevailing supply security standards as a benchmark for our reserve and response policies. However, we recognise that our policies may develop and change in the light of market circumstances and operational 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 (Primary Response, Secondary Response and High Frequency Response) that we will contract for through the mandatory frequency market; these are defined in the Grid Code. Other frequency response services will be procured through commercial routes such as the Firm Frequency Response (FFR) tender as and when they are required for operability reasons. These services will be procured through competitive markets unless there is a specific technical or commercial reason why this is not possible. More detail on the specific categories of response that we intend to procure over the coming year can be found within the Procurement Guidelines.

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. Non-dynamic response is delivered only when the system frequency reaches a set trigger point.

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.

A new suite of frequency response services have been implemented that is better suited both to the current and future operability challenges, and also the technical abilities of modern assets. This programme will deliver frequency response services that will be procured in line with this statement.

Dynamic Regulation (DR) is the new pre fault frequency service designed to slowly correct and deliver between +/- 0.015 and +/-0.2 frequency deviation. Dynamic Moderation (DM) is a pre fault frequency service designed to rapidly deliver between +/-0.1 and +/-0.2 frequency deviation.

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 six categories for system reserve which are detailed below:

(a) Contingency Reserve
This will be delivered primarily through the BM Start-up service 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. day ahead to pre Gate Closure timescales) 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 BMU offers.

(b) Regulating Reserve

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

It is envisaged that initially this service will be provided by BMUs that are voluntarily submitting suitable Bids-Offers to the BM 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.

Regulating reserve can be procured within the Balancing Reserve Market, o~~f~~n which more information can be found within the Procurement Guidelines.

(c) Short Term Operating Reserve (STOR)

STOR is provided by generation increase or demand reduction that can deliver reserve in short timescales. As with regulating reserve, it is required to cover for post Gate Closure plant loss and demand forecasting errors. STOR may be procured across differing timescales on an efficient basis in conjunction with consideration of wider obligations under the Electricity Transmission Licence.

Regulating reserve and STOR make up the total requirement dictated by Final Planning stage statistics and demand forecasting errors. The actual split between STOR and regulating reserve will be dictated by the economics of the provision of these services from the available sources across the relevant timescales.

(d) Fast Reserve

Fast reserve is a subset of regulating reserve and STOR, and is required for the maintenance of system frequency within operational limits. It is provided primarily by 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) BMU 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 BMUs 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 STOR or other reserves such that responsive BMUs 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 PN and other data from all BMUs 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 BMU requirement (i.e. that required to meet system demand and system response/reserve levels) is calculated from the sum of forecast demand, scheduled reserve[1], contingency reserve and STOR (less that provided by contracted non BMU sources).

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

Step 6 - The system plant margin for each half-hour period is then calculated by subtracting the identified BMU requirement from $\sum$ MEL (after accounting for BMUs 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 BMUs) – BM Unit Requirement

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

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 BMUs.

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 BMU) 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 BMUs required to maintain system security are available for selection in the BM.

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

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 BMU 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 BMUs wishing to actively participate in the BM.

Step 6 - In the BM, 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 BM window;

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

(vii) Services provided on Interconnector BMUs that could be operationally unacceptable to NGET, 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 5 and 6.

Part F: Summary of Operation of the GB transmission system from the National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS)

1. Overview

(a) We shall seek to operate the GB transmission system in accordance with the National Electricity Transmission System Security and Quality of Supply Standard as summarised so that for the secured event (as defined in the NETS SQSS) of a fault outage of any of the following:

- a single transmission circuit, a reactive compensator or other reactive power provider; or
- the most onerous loss of power infeed; or
- the most onerous loss of power outfeed; or
- where the system is designed to be secure against a fault outage of a section of busbar or mesh corner under planned outage conditions, a section of busbar or mesh corner,

there shall not be any of the following:

- a loss of supply capacity except as specified in the GBSQSS;
- unacceptable frequency conditions;
- unacceptable overloading of any primary transmission equipment;
- unacceptable voltage conditions; or
- system instability.

(b) and for the secured event of a fault outage of:

- a double circuit overhead line; or
- a section of busbar or mesh corner,

there shall not be any of the following:

- a loss of supply capacity greater than 1500 MW;
- unacceptable frequency conditions; or
- unacceptable voltage conditions affecting one or more Grid Supply Points for which the total group demand is greater than 1500 MW; or

- system instability of one or more generating units connected to the supergrid.

(c) and for the secured event on the supergrid of a fault outage of:

- a double circuit overhead line where any part of either circuit is in the England and Wales area; or
- a section of busbar or mesh corner in the England and Wales area,

there shall not be:

- unacceptable overloading of primary transmission equipment in the England and Wales area;
- unacceptable voltage conditions in the England and Wales area.

2. Conditional Further Operational Criteria

If conditions are adverse such that the likelihood of a double circuit overhead line fault is significantly higher than normal; or there is no significant economic justification for failing to secure the transmission system to this criterion and the probability of loss of supply capacity is not increased by following this criterion, the GB Transmission System shall be operated under prevailing system conditions so that for the secured event of:

- a fault outage on the supergrid of a double circuit overhead line

there shall not be:

- where possible and there is no significant economic penalty, any loss of supply capacity greater than 300 MW;
- unacceptable overloading of any primary transmission equipment;
- unacceptable voltage conditions;
- system instability.

1.1 Exceptions

Exceptions to the criteria may be required where variations to the standard connection designs have been agreed.

3. Frequency Control

There should not be “Unacceptable High or Low Frequency Conditions” under the conditions laid down in the Security and Quality of Supply Standard.

These are conditions where:

i) the steady state frequency falls outside the statutory limits of 49.5Hz to 50.5Hz; or

ii) a transient frequency deviation on the MITS persists outside the above statutory limits and does not recover to within 49.5Hz to 50.5Hz within 60 seconds.

Transient frequency deviations outside the limits of 49.5Hz and 50.5Hz shall only occur at intervals which ought to be reasonably considered as infrequent. It is not possible to be prescriptive with regard to the type of secured event which could lead to transient deviations since this will depend on the exact frequency response characteristics of the system which NGET shall adjust from time to time to meet the security and quality requirements of this Standard.

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 specified in OC6 of the Grid Code.

4~~3~~ Voltage Control

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 a voltage fall of 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 Grid Supply Points (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.