	Revision
1.0	0

The Statement of the Constraint Cost Target Modelling Methodology

Effective from 01 April 2017

About this Document

This document contains one of three methodologies that National Grid Electricity Transmission plc (NGET) employs to calculate the Modelled Target Costs, against which its actual balancing costs will be compared, on a month-by-month basis, under the Balancing Services Incentive Scheme (the 'Scheme').

The remaining methodologies are as follows:

- The Statement of the Energy Balancing Cost Target Modelling Methodology 2017-18
- The Statement of the Ex-Ante or Ex-Post Treatment of Modelling Inputs Methodology 2017-18

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Chapter 1: Modelled Target Costs

1.1 The Modelled Target Cost (in £ million) is defined in Special Condition 4C as "…the target cost to the licensee of procuring and using balancing services (being the external costs of the Balancing Services Activity)..." derived in accordance with the methodologies referred to in Part Fof Special Condition 4C …"

1.2 This document sets out the constraints methodology referred to in paragraph 4C.26 of Special Condition 4C. It should be read in conjunction with the other methodologies:

- The Statement of the Energy Balancing Cost Target Modelling Methodology; and
- The Statement of the Ex-Ante or Ex-Post Treatment of Modelling Inputs Methodology.

1.3 The target constraint cost is made up of the costs associated with actions taken in the balancing mechanism to manage constraints plus the costs associated with the replacement of constrained headroom and additionally costs associated with intertrips.

$$\begin{aligned}\text{CONSTRAINT\_COST\_TARGET}_t = \\ &\text{DF x TARGET\_BM\_COSTS}_t \\ &+ \text{TARGET\_HEADROOM\_REPLACEMENT\_COST}_t \\ &+ \text{TARGET\_ROCOF\_COST}_t \\ &+ \text{INTERTRIP\_COST}_t\end{aligned}$$

Where:

DF
A discount factor of 0.~~95~~78(to promote efficient cost management)

TARGET_BM_COSTS_t
Defined in Paragraph **2.4**

$\text{TARGET\_HEADROOM\_REPLACEMENT\_COST}_t$
Defined in Paragraph **6.2** as CONS_HR

$\text{TARGET\_ROCOF\_COST}_t$
Defined in Paragraph **7.14**

INTERTRIP_COST_t
Defined in Paragraph **4.28**

1.4 The incentive on constraint management encourages NGET to develop innovative configurations for operating its substations, explore contractual or service solutions to reduce constraint costs and agree mechanisms for Users to provide post-fault actions to manage the impact of faults.

Principles

1.5 The principles applied when modelling constraints costs are as shown in Figure **1** below:

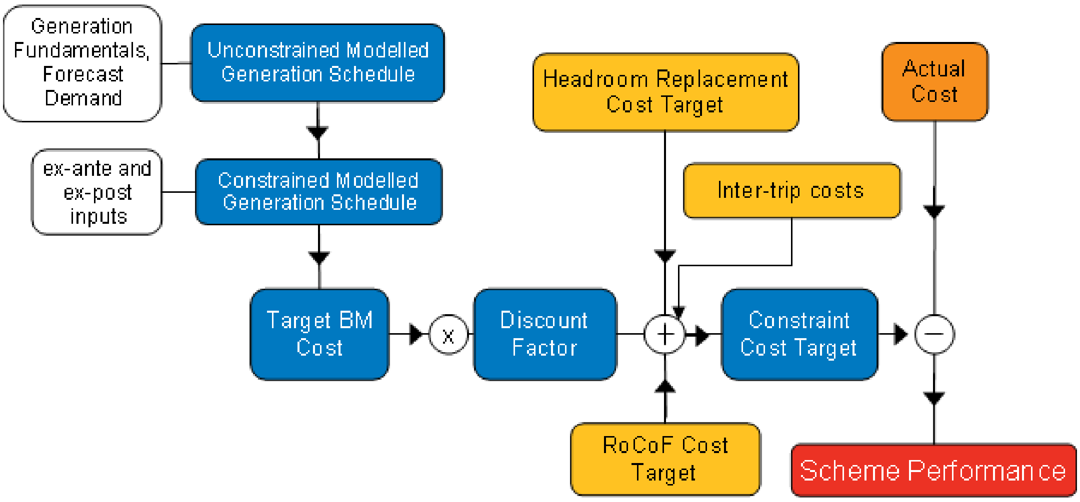

Figure 1: Overview of constraint modelling process

1.6 Plexos is power market modelling and simulation software from Energy Exemplar. This tool is used by NGET to model constraint costs.

1.7 The 'generation fundamentals' capabilities of Plexos are used to generate a schedule of plant to meet demand. The output of this schedule is 'unconstrained' – i.e. it assumes infinite transmission capacity. The model is then re-run introducing GB transmission network layout and associated boundary limits. The boundary limits are derived to represent flow limits across groups of transmission lines on an intact system as well as taking account of outages anticipated up to year ahead timescales initially, i.e. cut off for financial year 2017-18 would be 31 March 2017. The boundary limits are updated as the year progresses with boundary flow limits assessed at eight weeks ahead of real time based on the system conditions and outages planned at that time. Where a boundary limit is exceeded, the resulting constraint is resolved by Plexos through the re-scheduling of plant dispatch. This new plant dispatch solution is achieved through providing Plexos with a representation of offer and bid prices[1] submitted by participants into the balancing mechanism. This provides an overall 'constrained' schedule of plant dispatch that satisfies transmission system constraints and also meets demand.

1.8 The cost arising from moving the system from the unconstrained run to the constrained one gives a modelled target direct cost, which is then reduced by a discount factor. This is designed to recognise that resolution of constraints through the balancing mechanism is not the only or most efficient means to manage costs. It is therefore also intended to provide an incentive to derive efficiencies through the application of both existing and new balancing services and tools. The sum of this discounted modelled direct cost, plus the ROCOF Cost[2],the Headroom Replacement Cost[3] and Intertrip Costs gives the

[1] The derivation of the bid and offer price representations are described in more detail in sections 4.9 through 4.21
[2] See Chapter 7 for explanation of ROCOF costs

incentive target against which NGET's out-turn will be compared to determine its performance under the SO incentive.

1.9 In accordance with licence paragraph [4C.38] of licence Special Condition 4C, if NGET considers that an inaccuracy has occurred which prevents any model from reflecting the intent of modelling constraint costs, NGET shall notify the Authority of the model inaccuracy and its materiality together with a plan for remediation and then promptly seek approval to correct the model inaccuracy (s).

[3] See Chapter 6 for explanation of headroom replacement costs

Chapter 2: Plexos Model

Overview

2.1 The software application used to model constraint costs on the network is Plexos (from Energy Exemplar), as per BSIS 2011-13, BSIS 2013-15 and BSIS 2015-17. NGET has updated the model in Plexos for BSIS 2017-18. The version of the software has also been upgraded to 7.3 in line with recommendation from the vendor. The use of the Plexos software model for constraints modelling is based on the application of optimisation techniques aimed at minimising total BM costs.

2.2 The key output of the model is the anticipated total cost of constraints incurred by NGET in adjusting the self-dispatch position of generators in order to maintain a security standard on the network.

2.3 The first run of the model derives a simulation of market behaviour and applies the principal of an efficient market, self-dispatching to satisfy a forecast demand. The optimisation uses individual BMU heat rates or efficiency factors to derive a plant dispatch that minimises the short run marginal cost. The solution takes account of a number of additional plant dynamics including maximum export limit, stable export limit, minimum zero and non- zero times, etc.

2.4 The Modelled Target Cost for constraints results from the second run of the model. This looks to obtain a minimum cost to delivering a feasible plant dispatch solution for a given set of transmission system restrictions. The resultant plant dispatch solution away from the initial plant dispatch condition (as derived from the first run) is achieved through bid and offer acceptances in the balancing mechanism.

$$\text{TARGET\_BM\_COSTS}_t = Min \sum_{mt} Balancing\ \ Mechanism\ Costs_m$$

Subject to:

(i) Power flows being within limits of constrained boundary model
(ii) Supply equals demand
(iii) Generator dynamic ratings are not exceeded

Where: t is the Relevant Year within the scheme period
m is a particular month in the period under consideration.

Modelled network

2.5 The modelled network has been developed in line with the network used in operating timescales and the transmission system restrictions that are anticipated for each year within the scheme period.

2.6 The BSIS constraints model has been designed to be able to accommodate almost all potential transmission constraints which can occur on the GB system, in order to make the constraint cost forecast more accurate. These constraints can be thermal, voltage, or stability. The network model is defined at GB substation level, down to 275kV in England and Wales, and 132kV in Scotland: in other words, assets under the control of the System Operator, (SO) are explicitly modelled in the network topography. This represents the assets comprising the main interconnected system (MIS).

2.7 The modelled network is made up of nodes, lines and interfaces. Each individual substation which is part of the main interconnected system (MIS) is represented by a single node with a few exceptions as outlined in 2.8. There are also a few nodes which purely represent points where lines join together for example a T-point. The properties of a node are its load participation factor (LPF), the generation connected at that node and the lines to which it connects. The sum of the load participation factors of all the nodes must be equal to 1.

2.8 The nature of network system operation means that substation configurations are frequently switched by the SO. As practically it is only possible to manage one static network topology in the Plexos model, a snapshot of the GB system is used, showing substations, in a 'solid' electrical configuration (i.e. all points within the substation that are at the same nominal voltage are connected together) and all substations are connected with one to one representations of the real transmission circuits. The only exception to this rule is where a substation has fault infeed levels that are in excess of its switchgear ratings for a majority of the time. The number of substations affected by this is minimal.

2.9 A line is used to join nodes and although named with the actual asset code it represents a virtual connection between them (not the physical network). Therefore, the min and max flows are ±99999 MW as Plexos is not used to perform electrical load calculations, the physical characteristics of the transmission lines are not relevant (e.g. resistance and impedance values) as we are modelling transmission constraints using a boundary methodology.

2.10 The Western HVDC link between Scotland and England is due to commission in 2017-18. This is modelled as a line with a start date which will be updated ex post, after the asset is commissioned.

Interfaces and Boundaries

2.11 An interface is a collection of lines and serves as the Plexos representation of a boundary in NGET terminology, but to all intents and purposes they are the same thing. The interface is used to limit the flow across the boundary. The limit can be in a single direction across the interface or in both directions and can be time-varying. Each line that crosses an interface is a member of that interface. It is important to note that a line may be a member of more than one interface.

2.12 All substations and lines are present in the model. Any boundary which cuts any lines can be incorporated into the model. Any limitation of flow which cannot be represented by a group of lines, for example, a boundary which cuts through a split substation, can be accommodated by defining a rule from which Plexos creates a 'Constraint Object.' These can be applied to the model in the same way as interfaces.

2.13 The final property to be defined for an interface is the flow coefficient. This is a 'secondary property' as it is a property of a specific line and interface. If the reference line flow is defined in the same direction as the interface, the flow coefficient is 1. If the reference line flow is opposite to the interface, the flow coefficient is -1.

2.14 The location and number of boundaries and rules which have been selected by NGET are provisionally based on the year-ahead outage plan and the corresponding boundary limits do not reflect inter-trips. These are subsequently superseded by 8 week-ahead boundary limits, which may reflect intertrip capability, where relevant, and describe the resultant congestion on the transmission system prior to any further NGET optimisation. These are derived from historic data alongside operational experience of NGET power system engineers. Offline power systems studies are carried out where historic data is not available due to new outage combinations or changes to transmission system topology.

2.15 Some boundary limits and voltage constraints will vary as a result of the underlying generation mix. Where a boundary limit or voltage rule does vary as a function of underlying generation the most appropriate value will be applied. It is important to note that the different potential boundary limits or voltage rules will still be identified on an ex-ante basis.

2.16 Once commissioned, the Western HVDC link should relieve system congestion by increasing transfer capacity across some key boundaries in southern Scotland and northern England. This will be represented in the model by less onerous flow limits on several modelled boundaries post commissioning.

2.17 In order to commission the Western HVDC link, a series of successful commissioning tests will have to be performed and successfully completed. These tests will necessarily have to be performed over a period of time as system conditions allow. For example, in order to perform full load tests, a high generation export from Scotland to England may be required.

2.18 Boundary flow limits assessed at 8 weeks ahead of scheduled commissioned date, will have transfer capability assessed with both the Western HVDC Link available and unavailable, for the relevant boundaries affected. The ex post selection of the appropriate limit will then be built into the monthly process to best reflect system operation.

2.19 Until the Western HVDC link is fully commissioned, it is not available for operational purposes. It will be deemed commissioned in accordance with the procedure set out in STCP 19-4[4] . Upon successful commissioning, the relevant boundary limit from those described in 2.18 will be applied from the commissioning date

Demand and generation

2.20 Nodal demand has been derived based on the historical percentage of each node’s demand in relation to the total GB system demand, derived from December 2016 data.

2.21 Load Participation Factors are derived from data taken from a period where there was low PV and embedded wind output.

2.22 Transmission connected generation is connected to the GSP in the model to reflect its actual connection in reality. Embedded generation is connected to

[4] System Operator Transmission Owner Code http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/System-Operator-Transmission-Owner-Code/. STCP 19.4 covers procedure for commissioning and decommissioning assets on NETS

the most appropriate node which has been defined by the physical location of plant on the system.

2.23 The diagram below represents how Plexos 'sees' the GB electricity network with nodes being connected by lines across interfaces

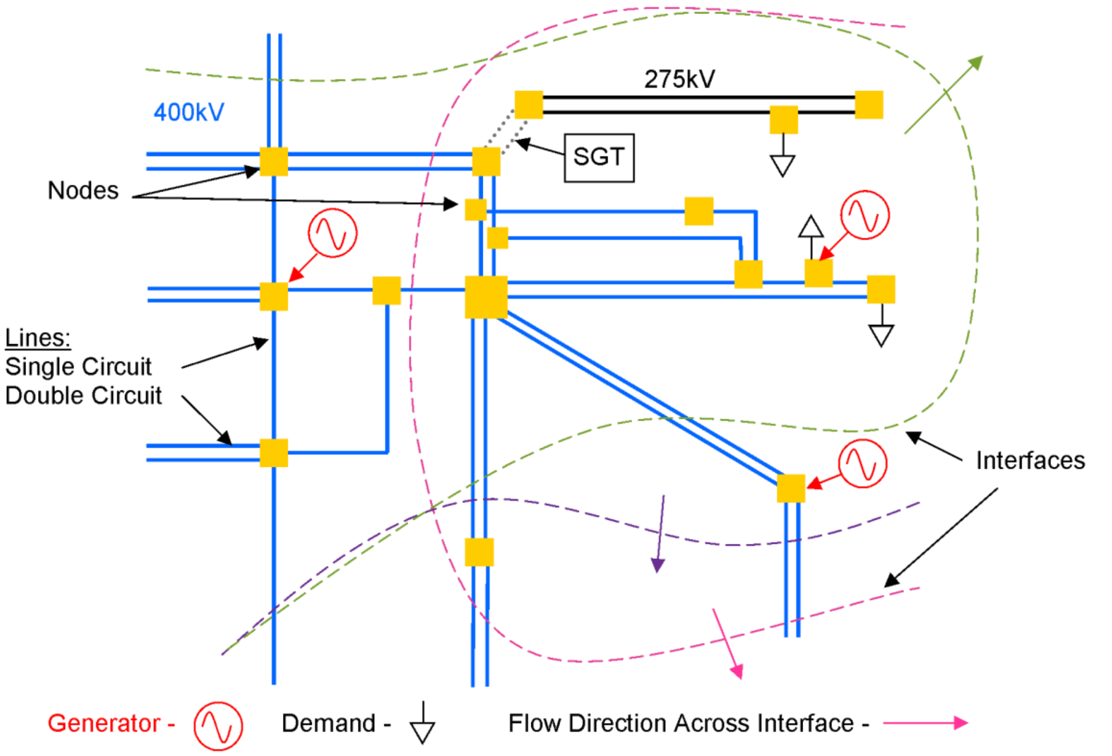

Figure 2 showing extract of E+W electricity network

2.24 Transformers on the GB system are represented by a line connecting two nodes at the same location but at different voltages (shown by grey dotted lines SGT).

2.25 In order for Plexos to distinguish between lines, NGET nomenclature codes are used (unique code given to each transmission asset on the GB system) preceded by one of the following:

Letter	Meaning
A	400kV line
B	275kV line
C	132kV line
F / S / T	Transformer

Table 1 showing Plexos line references

Boundary limits during outage conditions

2.26 Ex ante boundary limits restrictions for 2017-18 are initially determined in line with the year-ahead outage plan. For each boundary, a subset of the outages planned to take place throughout the outage year are selected. The selection process is based on historic data and the operational experience of power system engineers, and represents the most significant outages in relation to their impact on boundary transfer capabilities. Technical assessment of boundary limits and other restrictions are then carried out at 8 weeks ahead of real time as part of the standard process to support ENCC operations. For every week, from eight weeks following BSIS commencement, there will be a reassessed set of boundaries and flow limits produced by the standard technical process which will replace those formulated on the year-ahead plan, for that week. This closer to real time view of system boundary flow limits will assist the target model to better align with real system restrictions.

2.27 In the 8 week-ahead process the offline power system studies are used to calculate an appropriate power flow that can be accommodated across a particular boundary, using the appropriate short term rating. For each boundary, multiple contingencies (circuit trips) are run to establish the most onerous fault conditions. For the most onerous fault conditions, the maximum appropriate power flow that can be achieved across the boundary is calculated according to NETS SQSS requirements.

2.28 In the case of a thermal constraint, the year-ahead boundary limits have been calculated using the 20 minute short term rating of the worst overloaded circuits. This means that the maximum power flow across a boundary will be calculated to ensure that the power flows on these overloaded circuits can be reduced to their post fault continuous rating within 20 minutes. It's important to realise that this limit is achieved by selecting the most effective generation available in reducing those overloaded circuits. The post fault generator effectiveness is considered in a similar way for other types of constraint that can occur. The 8 week-ahead limits should be assessed using the most credible choice of short term rating for the scenario studied. A move away from 20 minute short term ratings may be possible if there is a greater degree of certainty on how the restriction can be managed in the event of an overload. This may result in less onerous flow restrictions in 8 week- ahead timescales.

2.29 In addition, NGET will apply logical rules to generators to model constraints which are not able to be modelled via boundaries. For example, if a specific number of generators are required for voltage support, then the model will ensure that they are running. If there is an outage at a substation that is local to a generator, then this can be modelled by a logical rule which restricts the output of the generator accordingly. These rules will be updated in 8 week-ahead timescales where required.

2.30 Limits are also a function of generation and demand backgrounds and can for example change between night and day or weekday and weekend.

2.31 The boundary limits are applied to the interfaces between the interconnected nodes.

2.32 In accordance with licence paragraph [4C.38] of licence Special Condition 4C, if NGET considers that a model inaccuracy(s) has occurred in the Constraint model in relation to the calculation of boundary flows; NGET shall notify the Authority of the inaccuracy(s) and its materiality, together with a plan for remediation and then promptly seek approval to correct the inaccuracy(s).

Model Settings and Erroneous data management

2.33 The optimising software is a commercially available tool. There are multiple settings within the software and there may be occasions where these need to be changed.

2.34 NGET will analyse model optimisation to ensure the unconstrained / constrained model settings are appropriate. In accordance with licence paragraph 4C.38 of Special Condition 4C, where NGET finds an inaccuracy(s) in model settings which prevents the model from appropriately reflecting this methodology statement, NGET shall notify the Authority of the inaccuracy(s) and its materiality, together with a plan for remediation and then promptly seek approval to correct the model inaccuracy(s).

2.35 If NGET detects data that it believes is erroneous (i.e. bad data), NGET will verify with the generator in question that the BM data was submitted in error.

2.36 In accordance with licence paragraph [4C.38] of Special Condition 4C, if NGET considers that an input error(s) has occurred as a result of information submitted by a third party, NGET shall notify the Authority of the inaccuracy(s) and its materiality and promptly seek approval to correct the model inaccuracy(s).

Out of scope

2.37 Transmission system losses and net imbalance volume (NIV) are ignored in order to ensure that total demand equals total supply.

Chapter 3: Unconstrained model

Overview

3.1 The objective function of the unconstrained model is to minimise the sum of the short run marginal cost of generation dispatch when no boundary limits are present.

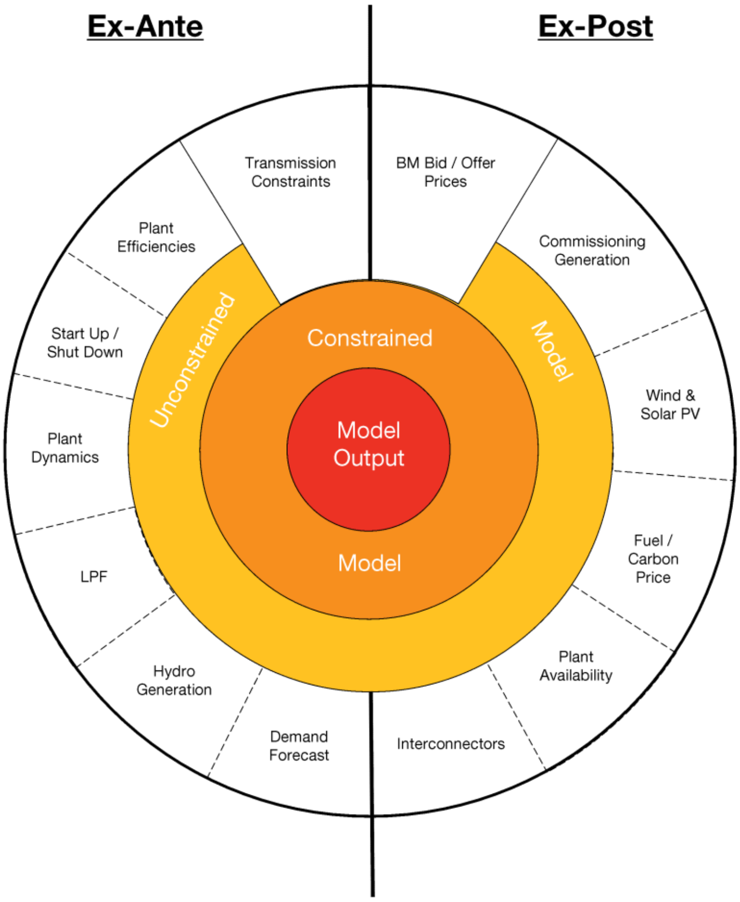

Figure 3: Output Model

3.2 The diagram above illustrates the full run of the model; starting with the inputs around the outer circle, going through the unconstrained model, where the output is joined by Transmission Constraints and BM bid / offer prices before the constrained model is run giving the final output at the centre circle. The diagram shows which inputs are ex-ante and which are ex-post, this is explained in further detail below.

Generation dispatch

3.3 Using demand forecast, known historic running patterns, fuel and carbon prices, plant efficiencies, start-up costs, generator availability, wind and hydro generation data and interconnector flows, a generator running schedule is derived that minimises the short run marginal cost of generation. This is done without regard to the transmission system as the market dispatch under BETTA disregards location.

Inputs for deriving target cost

3.4 The first crucial data required is the demand forecast which is to be met by generation in the model. Demand forecast, an ex-ante input, is obtained through the well-established processes within NGET. Demand is forecast at a

GB level and apportioned to grid supply points based on observed and understood relationships.

3.5 The demand forecast is a seven day ahead ex ante forecast based on forecast weather and uses recent observations of demand against forecast and understanding of the output of embedded wind and solar PV generation against forecast to give a refined half hourly demand profile forecast plus embedded wind and solar PV generation. The model will use the 7 day-ahead demand forecast for each period. For example, period 35 on 1st June 2017 will use the last available 7 day-ahead demand forecast produced for that period.. For the remaining periods of the year for which a 7-day ahead demand forecast has not yet been produced, we will revert to the full year ahead forecast. This will subsequently be superseded by the relevant 7- day ahead demand forecast.

3.6 To achieve the initial run (the unconstrained dispatch), a number of inputs are provided for each generation unit, including:

- Fuel price
- Carbon prices
- Plant efficiencies
- Start-up / Shut-down costs
- Plant dynamic parameters
- Availability
- Commissioning generation output (if applicable)
- Must run parameters based on historic generation

3.7 In addition to these inputs and demand as previously detailed, interconnector flows, solar PV output and wind generation output files are also fed in to the unconstrained run of the model to enable a dispatch of unconstrained generation to be produced.

Fuel and carbon prices

3.8 In order to input large amounts of time varying data, input data files are used. The fuel prices are measured in £/GJ, and the carbon price is measured in £/kg. Emissions costs are included in dispatch decisions. For the unconstrained model, they are as follows:

Data file name	Description	Source[5]
Gas Price	Daily gas price in £/GJ	Bloomberg- Day Ahead Spot price at NBP
Coal price	Daily coal price in £/GJ	Bloomberg – Generic CIF ARA Steam Coal forward price
Carbon price	Annual carbon price in £/kg plus any relevant Government imposed additional Carbon Support Price (details see **3.9**)	Bloomberg – European Futures Contract for Carbon
Oil	Monthly price in £/GJ	Bloomberg – Crude Oil, Brent Futures Price

Table 2 describing the input data files

Carbon Support Price

3.9 The carbon support price is a charge levied on generators of electricity using fossil fuels. This impacts the overall costs of generating electricity and consequently the merit order which the model uses to determine the order of dispatch.

3.10 The current CSP rates are as follows: (Source: https://www.gov.uk/climate-change-levy-application-rates-and-exemptions#carbon-price-support-rates)

Fuel	Rates 1 April 2017 to 31 March 2018
Gas (£ per kilowatt hour)	0.00331
LPG (£ per kilogram)	0.05280
Coal and other solid fossil fuels (£ per gigajoule on gross calorific value)	1.54790

Table 3 Carbon Support Rates

Plant dynamic parameters, efficiencies and start-up costs

3.11 Plant dynamic parameters are detailed below.

[5] The Bloomberg indices used as source data are NBPGDAHD, API21MON, ICEDEUA and EUCRBRDT. The Bloomberg exchange rates used to convert the prices into GBP are GBPUSDGN and GBPEURGN with the addition of an appropriate unit conversion formula. If any of these sources become discontinued or unavailable, a decision will be sought from Ofgem regarding a suitable alternative and whether it should be applied retrospectively.

3.12 Data sources used by generation plants are given in the table below:

Input	Source
BMU Heat rates	Ex-ante, based on historic generation.
VO&M cost	Ex-ante, based on market intelligence.
Start Up & Shut Down cost	Ex-ante, based on market intelligence/ analysis.
Technical plant parameters	Ex-ante, based on market intelligence.

Table 4 describing data sources for generation plants

3.13 BMU heat rates are the energy input required for 1MWh of output.

Heat rate = Potential Energy [GJ]/Electrical Energy output [MWh]

Efficiency = Electrical Energy Output [GJ]/Potential Energy Input [GJ]

Since, 1MWh = 3.6 GJ,

BMU heat rates= 3.6/Efficiency

3.14 VO&M (Variable Operation and Maintenance) charge is a component of the incremental cost of generation per megawatt hour. It is used to recover maintenance costs which are a direct function of generation such as wear and tear and other servicing costs. It is factored into units' short-run marginal costs.

3.15 Start up / shut down costs for existing units are estimated in a similar way as that of efficiencies, i.e. through simulating historic market conditions and adjusting the costs until a reasonable match is reached. A full recalibration of the unconstrained dispatch against historic running patterns was undertaken. As it is not possible to verify individual start-up / shut down costs we use these parameters to improve the calibration only.

3.16 Selected generators will be treated as "must run". These generators support industrial processes. As such they will always run when available to do so.

3.17 Some other generators will be treated as a "must run at SEL, (stable export limit) or above" with the model free to dispatch the economically optimal level at or above SEL for each of these units.

3.18 Generation availability is treated as an ex-post input to the unconstrained run of the model where outturn MEL / SEL data, at 6 hours ahead, is employed as the source data. This will be taken for each BM unit for each settlement period and input to the model on a monthly basis in line with other ex-post inputs.

3.19 In some instances, it is necessary to put commercial contractual arrangements in place to secure a specific availability on a generator in order to manage a constraint. Typically, these arrangements are put in place with BMUs that require significant advanced notice of the need to adjust their output, for example on nuclear generation.

3.20 Under REMIT[6], generators are obliged to submit their best view of BMU availability and this will be reflected in their MEL submissions. In order to recognise the forward actions taken by NGET in the model, it is necessary to substitute the actual MEL submissions for the period(s) pertaining to the commercial agreement.

3.21 Where commercial contractual arrangements have been made to secure availability of a generator to manage constraints (to either higher or lower levels than is customary[7] for a generator) then MEL 6 hour ahead submissions will be replaced by 99th percentile MEL value from historic submissions over the previous year. The contracted generators' modelled output will then be reflective of their availability prior to the contract engagement. The SEL of the BMU will also be realigned if necessary to ensure consistency.

3.22 In order to maintain transparency, NGET will make available to the Authority, details of any contracts entered into on this basis.

3.23 The source of the MEL data will be the National Grid Economic Data warehouse (NED), a system that stores and aggregates operational and half-hourly settlement data. On the rare occasions when this data is not available but the generator is available, one of the following alternatives will be used (in order of preference)

(i) MEL / SEL at gate closure (1 hour ahead)
(ii) MEL / SEL at real time
(iii) The last submitted value by that unit
(iv) An average of submitted values from other units of the same type at the same power station.

3.24 Commissioning generation is treated as an ex-post input to the model for the first 6 months of operation. Its output will be modelled in the same way as all other generation thereafter. Generation which undergoes conversion to a new fuel type will be treated as a newly commissioning generator.

3.25 Cross-border interconnector flows (HVDC) will be modelled at the intraday gate closure position i.e. will be input to the model on an ex-post basis. This input data will be derived using Elexon settlement final physical notification (FPN) for interconnector BMUs, excluding system/error admin accounts, minus trade volumes classified for 'System' needs from NGET's Energy Trade Management System (ETMS). Any further interconnectors would be added to the model at the point of commissioning and handled in the same way as existing interconnection.

3.26 In addition to the above, further inputs are required to fully represent generation levels on the system. These are described in further detail in **Chapter 5: Generation**:

- Hydro generation running assumptions, see **5.12** - **5.18**

[6] REMIT – Regulation on Energy Market Integrity and Transparency
[7] 'customary' defined as the expected economic output level or that level evidenced by previous running pattern established in prior 3 months

- Interconnector assumptions, see **5.19** - **5.20**

Outputs

3.27 The unconstrained model delivers a number of outputs which are written to a file as shown in the table below. These are then used as inputs for the constrained model.

Data file name	Description
FPN	Generation, used as Base Generation profile input
MEL	Available capacity
FPN to SEL	The difference in volume between generation and generator's stable export limit. This is calculated as Min (0, SEL-FPN)
SRMC	Short run marginal cost
Pump Load	Pumping, used as Base pumping profile input
IsOperating	Will have a value of True if the unit is generating and False at all other times (only applies to generation side)

Table 5 showing unconstrained model outputs

Chapter 4: Constrained Model

Overview

4.1 The forecast of constraint costs is done by running a simulation of the system unconstrained followed by a run with boundary limits included, using the result from the first run as the starting position of the generating units. Each unit is assigned a set of prices as part of the balancing mechanism explained below and the optimisation engine identifies the minimum cost to move the system from the original position to a feasible position, given the transmission constraints. The diagram below illustrates the second run of the model which will determine the generation output of the constrained system. The inputs are BM bid/offer prices as well as transmission constraint boundary limits (explained in paragraph **4.23**).

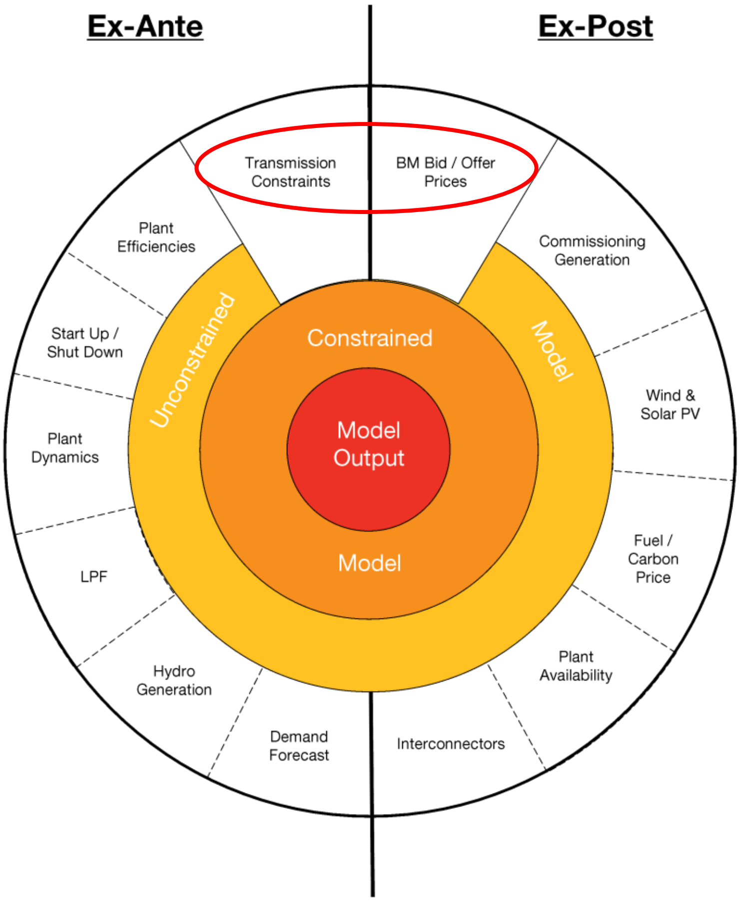

Figure 4 Output Model

4.2 This second run of the model factors in the limitations of the transmission network. The difference between the constrained and unconstrained runs represents the model's assessment of the required volume and associated cost of constraint management activities. The generation output levels from the unconstrained model are used as inputs to the constrained model where Plexos re-dispatches generation to meet demand, whilst considerations to the boundary constraints and the submitted prices for re-scheduling plant are applied.

4.3 Where a boundary's capability is exceeded, the resulting constraint is resolved through re-scheduling plant. This is achieved using a representation of offer and bid prices submitted into the balancing mechanism as described in **4.9** through **4.21**. This provides a 'constrained' schedule of plant that satisfies transmission system constraints whilst meeting demand.

4.4 The sum of accepted bid and offer costs will be processed as required in Appendix A, then multiplied by the discount factor to determine the modelled target costs, and will be used to determine NGET's performance under the incentive.

4.5 The following section describes the way in which the model is constructed, including simulation of the balancing mechanism.

Balancing Mechanism

4.6 The objective function used for the constrained model is to minimise total amount of money spent on the balancing mechanism subject to the boundary limits (and other constraints) set in the model above.

4.7 The balancing mechanism is exclusively used in the constrained model. It is simulated through four bid/offer price-quantity pairs, as described in **4.11**, and using the unconstrained dispatch model as an initial condition.

4.8 The unconstrained dispatch shall be changed to respect interface limits, and where arbitrage opportunities exist between generators, they shall be taken.

Generation

4.9 Offer Base is the unconstrained generation (FPN). This is the generator self-dispatch level and therefore the base level for each generator in the balancing mechanism.

4.10 Offer Prices are read in three bands and are conditional on whether the generator is operating. When generating, the three bands are to move between FPN and off (De-sync Bid), FPN and SEL (Energy Bid) and FPN and Max availability (Energy Offer). When not generating, the first two bands are zero, and the third band is to take the generator up to SEL (Sync Offer).

4.11 Four prices are used because there are broadly four categories of actions in the BM that have different price drivers; they, and their drivers, are as follows:

- De-sync Bids - the submitted bids on a unit to reduce its output from SEL to zero. One would expect the price to reflect the value of the fuel saved and/or subsidy forgone, and also the cost of increased maintenance due to the extra synchronisation that will occur at a future time.
- Energy Bids - the submitted bids on a unit to reduce its output from FPN towards SEL. One would expect the price to reflect the value of the fuel saved and/or subsidy forgone.
- Energy Offers - the offers on a synchronised unit above SEL. One would expect the price to reflect the cost of fuel used plus an opportunity element.
- Sync Offers - the submitted offers on a unit to switch the unit on and increase its output to SEL. One would expect the price to reflect the cost of fuel used, and the maintenance cost due to the synchronisation event.

4.12 To derive the prices for the four operating modes described above, the volume weighted average offer and bid prices are calculated on a half hourly basis for each BMU, using an ex-post input of actual submitted prices. These are calculated from the capped physical notification (CPN) which is defined as the minimum value of the final physical notification and the maximum export level. Using the CPN, the offer prices can be calculated for their corresponding offer quantities. From these, the weighted average per half hour per BMU for each operating mode can be found. These are the prices used in the constrained model.

4.13 The tables below give the relationship between the three Plexos bands and the corresponding offer prices and quantities.

	Model Price	
Band	When Operating	When Off
1	De-sync Bid	0
2	Energy Bid	0
3	Energy Offer	Sync Offer

Table 6 showing offer price bands

	Model Quantity	
Band	When Operating	When Off
1	-99999MW	0
2	Min(0, SEL – FPN)	0
3	99999MW	99999MW

Table 7 showing offer quantity bands

4.14 Offer and bid quantities are calculated based on an unconstrained dispatch. Negative quantities are used for bands 1 and 2 to denote bids for reducing output below FPN. Note that although bands 1 and 3 are set values, Plexos caps the value based on the generator parameters. The three offer quantity bands for an operating generator are illustrated in **Figure 5**.

Pumping Load

4.15 For pump storage units, prices and volumes for actions affecting the amount of pumping are required.

4.16 Pumping Bid Base is the unconstrained pumping (FPN). This is the generator self-dispatch level and therefore the base level for each generator in the balancing mechanism

4.17 Pumping Bid prices are read in two bands; to move between a negative FPN and zero (Pump Offer), or max availability between zero and MIL (Pump Bid).

4.18 Two prices are used because there are two categories of actions in the BM that have different price drivers; they, and their drivers, are as follows:

- Pump Bids - the submitted bids on a unit to increase its pumping load. One would expect the price to broadly reflect the cost of energy used.
- Pump Offers - the offers on a unit to reduce its load from a negative FPN towards zero. One would expect the price to broadly reflect the value of energy saved.

4.19 To derive the prices for the two Plexos bands described above, the volume weighted average of the submitted offer price for each BMU, is calculated for each half-hour period. These are calculated from the capped physical notification (CPN) which is defined as the minimum value of the final physical notification and the maximum export level. Using the CPN, the bid prices can be calculated for their corresponding bid quantities. From these, the weighted average per half hour per BMU for each band can be found. These are the prices used in the constrained model.

4.20 The tables below give the relationship between the two Plexos bands and the corresponding bid prices and quantities.

Pumping Bid Price	
Band	**Pumping**
1	Pump Offer
2	Pump Bid

Table 8 showing pumping bid price bands

Pumping Bid Quantity	
Band	**Pumping**
1	-99999MW
2	99999MW

Table 9 showing pumping bid quantity bands

4.21 Offer and bid quantities are calculated based on unconstrained dispatch. Negative quantities are used for band 1 to denote offers for reducing load below FPN. Note that although bands 1 and 2 are set values, Plexos caps the value based on the pumped storage generator parameters. The two pumping bid quantity bands for an operating generator are illustrated in **Figure 5**.

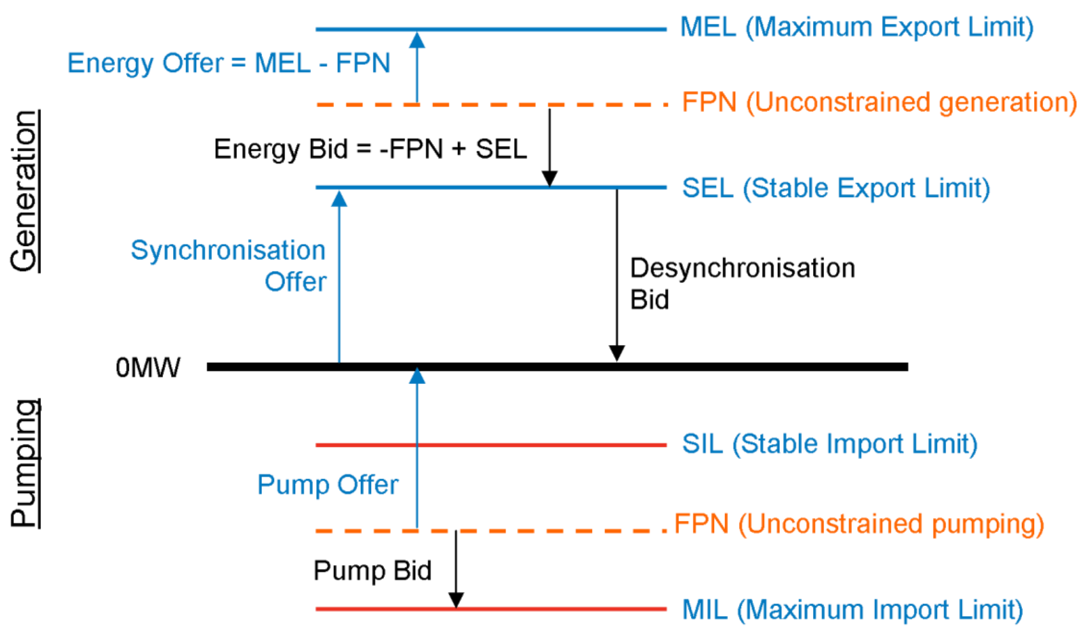

Figure 5 showing the balancing mechanism price-quantity relationships

4.22 The model will take any number of the above actions in whatever combination is most economic on a particular unit, given its dynamic parameters.

Data Inputs

4.23 In addition to the inputs to the unconstrained model, the constrained model has additional data file inputs for the balancing mechanism and the boundary limits. These are as follows:

Input name	Description	Source
Generation		
FPN	Used as Offer Base input for generation; Half-hourly generation level of each asset.	Unconstrained model
MEL	Energy offer volume, also used for the Synch Offer volume	Unconstrained model
FPN to SEL	Energy Bid volume, only applied when unit is generating	Unconstrained model
IsOperating	Flag to indicate what state the generator was in when unconstrained.	Unconstrained model
De-sync Bid	Bid price to turn off	Volume weighted average of bid prices submitted in the BM between SEL and 0, subject to the condition FPN > 0
Sync Offer	Offer price to turn on. Only used when plant is off in the unconstrained solution	Volume weighted average of offer prices submitted in the BM between 0 and SEL, subject to the condition FPN = 0
Energy Bid	Price to turn down from present level to SEL (minimum stable level)	Volume weighted average of bid prices submitted in the BM between FPN and SEL, subject to the condition FPN > SEL
Energy Offer	Price to turn up from present level to max capacity.	Volume weighted average of offer prices submitted in the BM between FPN and MEL, subject to the condition SEL ≤ FPN < MEL
Pumping		
-FPN	Used as Pumping Bid Base input for pumping; Half-hourly generation level of each asset.	Unconstrained model
Pump Offer	Price to reduce pumping from present level towards 0	Volume weighted average of bid prices submitted in the BM between FPN and 0, subject to the condition FPN < 0
Pump Bid	Price to increase pumping from present level towards MIL	Volume weighted average of bid prices submitted in the BM between FPN and MIL, subject to the condition 0 > FPN > MIL

Input name	Description	Source
Transmission Constraints		
Import Limit	Limit on flow across an interface in the direction away from a central system reference point,	Determined by NGET (explained in chapter 2)
Export Limit	Limit on flow across an interface in the direction towards a central system reference point,	Determined by NGET (explained in chapter 2)

Table 10 showing input sources for the constrained model

4.24 On the rare occasion that the relevant prices are not available, then a number of options exist. These are listed below in order of preference and, subject to data availability, capped (or collared) to avoid the possibility for self-arbitrage[8]:

(i) The last relevant price can be used
(ii) Else, the average of all units of the same fuel type at the node can be used
(iii) If none of the above is possible, then the average of the same fuel type at neighbouring Plexos nodes.
(iv) Alternatively, the average price of the same fuel type within the country can be used.
(v) Finally, the average price of the same fuel type within GB can be used.

Intertrips

4.25 Intertrips are not modelled explicitly. Intertrip arming can support a higher boundary flow capability. If an intertrip has existed for four years or more and where it is, in real time, operationally and commercially viable, then any resultant additional capability will be applied to the 8 week ahead boundary limit. This removes from the constraint target any benefit produced by the arming of these intertrips.

4.26 It should be noted, that a majority of inter-trips have an associated cost when they are armed. These costs will be added to the constraint model target on an ex-post basis if and when they are armed. For the avoidance of doubt, these will be added to the target after the application of the discount factor.

4.27 In the unlikely event of a transmission fault occurring when an intertrip is armed, thus causing the intertrip to operate, any costs payable to the generator due to the intertrip operation will be added as a pass-through cost to the constraint model target on an ex-post basis. For the avoidance of doubt, these will be added to the target after the application of the discount factor.

4.28 $INTERTRIP\_COST_t$= (Sum of all costs associated with Intertrips[9])

Ensuring a Credible Target

4.29 The constraint boundaries and voltage rules that are applied to the model are derived at 8 weeks ahead. This process is intended to set a baseline for all

[8] Self-arbitrage is accepting bids and offers at the same unit to generate a net income to the SO. The BSC requires that the prices submitted to the BM do not allow for self arbitrage.
[9] Only Intertrips with commercial agreements in place 4 years or longer

boundaries on the system, reflecting the expected conditions on the NETS on a holistic basis.

4.30 In a limited number of circumstances, the process could produce lower boundary conditions or tighter voltage rules, which could result in the modelled target cost being too high and not reflecting the observed operational conditions. If the monthly target exceeds 2 standard deviations of historic outturn, National Grid must provide evidence as to why the target is justified.

4.31 If National Grid do not consider or cannot convince the Authority that a constraint limit is credible, and the Authority has reason to believe, based on historical comparison, that a constraint limit is not credible, National Grid will seek to improve the modelled target by submitting an alternative boundary limit for approval to the Authority, together with a justification. The proposed boundary limit will be less restrictive than the 8 week ahead boundary limit, or in the case of a voltage rules revision, a lower requirement than that set at 8 week ahead. The intent of any such proposal will be to produce a lower modelled target cost than that derived by application of the 8 week ahead limit

4.32 For the avoidance of doubt, if an operational boundary limit improves as a result of a change to the standard running arrangement, or as a result of a clear set of actions or strategy employed by the System Operator, the 8 week ahead boundary will stand. Furthermore, if the operational limit improves as a result of a change to the underlying plant despatch in operational timescales the boundary will stand. This is because the potential impact that these actions or strategies might have is accounted for in the discount factor.

Outputs

4.33 The outputs from the constrained model are the actions taken and the extent of congestion, giving the constraint volumes (cleared offer quantities) in total and per generator along with the cleared constraint costs. The sum of all the units cleared offer costs and cleared pump bid costs makes the total BM cost of resolving the constraints. This is to be used to produce the target for the incentive scheme.

4.34 Processing of Plexos output data (cleared offer costs and volumes) from the constrained run may be required to create the Constraint Cost Modelled Target where there exists ‘High cost-low volume actions’ as defined in **5.26** and Appendix A.

4.35 In accordance with licence paragraph [4C.38] of Special Condition 4C, if NGET become aware of significant issues which indicate the existence of a model inaccuracy in the Constraint model related to target costs, NGET shall notify the Authority of the inaccuracy(s) and its materiality and promptly seek approval to correct the model inaccuracy(s).

4.36 In past schemes, we have received erroneous data from third parties, for example an incorrect MEL or price submission that may have occurred for just one settlement period. Such data can potentially affect the model target.

4.37 In the event a third party data error occurs that could potentially affect the model cost target, NGET will seek to confirm the error with the third party and correct the error. Details of the correction, along with third party confirmation will be provided to the Authority. For the avoidance of doubt this approach will only be taken for third party errors. Any other model inaccuracies or error will be corrected in accordance with the process described in 4.30

Chapter 5: Generation

Overview

5.1 This section describes how non-conventional forms of generation are treated within the model.

Transmission Connected Wind Generators

5.2 Wind is an intermittent generator which currently has little capability to respond to price signals or instruction from National Grid (it can turn down/off, but cannot turn up).

5.3 Settlement meter data will be used as an ex-post model input for wind where available. Settlement meter data is the half-hourly time series of power output for each wind generator in MW. Where this data is not available we will use the MERRA (https://gmao.gsfc.nasa.gov/merra/) dataset in the same manner as set out for the treatment of embedded wind generation.

5.4 Wind is modelled using the percentage of available capacity and ex-post wind output data. This will be half hourly metered wind output data.

Input	Description	Source
Variable wind	Ex-post half hourly wind generation	Settlement metering, adjusted for any BM actions and/or trades taken on the unit

Table 11 showing the wind data input to the model

Embedded Wind and Non Settlement Metered Wind Generators

5.5 Embedded wind is modelled on a regional basis: that is to say the network model is divided into approximately ninety regions for the purpose of forecasting wind generation.

5.6 Hourly historical weather data will be extracted from the MERRA dataset for each of the ninety regions, and used to generate hourly load factors. Each embedded wind generator which is included in the constraints model is assigned to one of the ninety regions and allocated the respective hourly load factor. Each of the embedded wind generators is electrically connected to the transmission network model at the relevant Grid Supply Point (GSP) / TO substation, or where that information is not available, to the closest appropriate TO substation.

5.7 Embedded wind is assigned a default high price to reflect their non-participation in the BM and therefore inability to control their output. Plexos then deems actions at these units uneconomic. Any action taken at these units is re-priced according to Appendix A.

Monitoring of New Wind Farm Connections

5.8 It is important to ensure that as new wind farms are connected to the electricity network, the model is kept up to date to ensure that the metered output of the wind farms ex-post can be input and their contribution to meeting demand more accurately modelled. Hence, a list of all wind farms along with the nodes at which they are connected, their connection dates and capacity will be maintained on a monthly basis. This will replicate NGETs Energy

Forecasting System (EFS). Updates to new generation connections for which Elexon data is unavailable, such as for embedded wind farms, will be made using an appropriate auditable source (currently Ofgem's data record).

Solar PV

5.9 Solar PV is handled in much the same way as embedded wind generation. Utilising actual outturn weather data from the Met Office, an estimate of Solar PV generation is calculated at a number of regions across the country based on the generation capacity within each region. This aligns with National Grid's current solar PV forecasting capability.

5.10 Solar PV regions may be updated on a monthly basis throughout the scheme, reflecting changes to number of regions, their definition, generation capacity and other related properties.

5.11 Solar PV units are set as 'must run' and will therefore generate in the model at the level estimated by the above description.

Hydro

5.12 Hydro is modelled in two ways – pumped storage and run of river.

5.13 Run of river is modelled by assuming a monthly water inflow into a head pond. Plexos then optimises the release of this water to generate electricity. The observed monthly hydro generation is used to calculate the average value.

5.14 Pumped storage is dispatched based on price differential within a day. If there is sufficient price differential during the day, Plexos will schedule pumping at times of low price and generation at times of high price.

5.15 Pumped storage plants are modelled as a closed system comprising a head storage and a tail storage, shared between the multiple BM units at each plant. There are no energy flows into or out of the head or tail storages other than from generating or pumping. A pump efficiency is also defined for each pumped storage generator.

5.16 Pumped storage utilisation is optimised on a daily basis. In the unconstrained model, pumped storage will arbitrage between peak and off-peak periods in order to lower system-wide generation costs in the objective function.

5.17 The treatment of pumped storage units with respect to unconstrained model outputs is as follows.

- The unconstrained period-level output of each generator, including pumped storage units, is passed to the constrained model run.
- When pumped storage units are pumping rather than generating, this is reported by Plexos as pump load rather than negative generation.
- However, across the system as a whole, the unconstrained generation output will increase in order to meet pumping load.

5.18 In the constrained model, deviations in pumped storage generation (due to transmission constraints for example) from the initial FPN position are optimised in the same manner as for other generators.

Interconnected Markets

5.19 Interconnected markets can drive constraint levels across certain key boundaries, either as sink (export) or source (import). The GB system presently has four interconnectors (GB-France), Moyle (GB-NI), BritNed (GB-Netherlands) and the East-West (GB-Eire).

5.20 In order to accurately reflect the impact of cross-border interconnector flows on constraints within the model, Interconnectors flows (HVDC) will be modelled at the intraday gate closure position i.e. will be input to the model on an ex-post basis. This input data will be derived using Elexon settlement Final Physical Notifications (FPNs) for interconnector BMUs, excluding system/error admin accounts and minus trade volumes for system needs only from NGET's Energy Trade Management System (ETMS).

Embedded BMUs

5.21 Some generators that are also nominally BMU's due to their capacity are embedded and can operate using a non-conventional fuel or may provide power to an aligned process or specific demand requirement.

5.22 There are two particular BMUs that we have identified, Markinch and Fellside whose output cannot be determined because they meet a specific demand requirement. In the case of Markinch it supplies steam to a paper plant and for Fellside it provides power to the nuclear reprocessing plant.

5.23 Our analysis suggests that they meet varied demand requirements across the year but when they are operating they do not offer flexibility and they do not operate within the context of a competitive, heat rate driven, market dispatch. In order to model their potentially significant output, we set their SEL to MEL to prevent the model dispatching them within the overall market optimisation.

5.24 If any additional generators were identified that operate in this manner we would apply this same methodology. For avoidance of doubt this would not be deemed a model inaccuracy, but we would make note and inform the Authority through normal reporting processes

High Cost-Low Volume Actions

5.25 Very high prices are attached to offer acceptance actions which the control room are unlikely or unable to take, e.g. on non BM-wind or nuclear generators. For non-BM wind (where National Grid has no way to commercially instruct them), a very high default price of -£99999/MWh is set to discourage Plexos from selecting this bid to resolve constraints. Nuclear units do submit BM prices at typically very high levels (+/- £10000/MWh) to indicate their inflexibility to alter their output.

5.26 In situations where Plexos has no other option than to take a very high cost action to resolve a constraint, this potentially leads to an unrealistically high constraints target. In order to more accurately reflect the costs of actions available to the control room, a method of re-pricing will be employed.

5.27 Appendix A details the criteria used to determine the High Cost-Low Volume actions to be removed, and the representative replacement costs.

5.28 Any actions which meet the listed criteria will be deducted from the monthly modelled Plexos constraints target cost. The volume of bids/offers extracted from the cost target then need to be replaced by representative cost bids/offers to allow additional target to cover these actions. The resolution of system constraints required the total volume of bids/offers in certain locations to be exercised. In order that the cost target is reflective of this volume of actions a realistic price substitute should be added back into the target.

Chapter 6: Headroom Replacement Costs

Overview

6.1 Headroom represents spare capacity on operating generating units which NGET can potentially access to meet its reserve requirements. Headroom may become inaccessible due to transmission constraints in the case of generators located behind an export constraint boundary. The cost of replacing this 'sterilised headroom' can contribute materially to overall constraint costs. If an action is taken to completely replace sterilised operational margin, then the costs are assigned to constraint costs.

6.2 The headroom replacement costs for each month will be calculated as follows:

CONS_HR =
-1150170
+ 66102.48 * VWA_Op_Reserve_P
+ 35.69219 * CMM_V

Where

CMM_V is Constrained Margin Management Volume which is dependent on the Plexos output Constraint_Bid_V.
VWA_Op_Reserve_P is monthly operational reserve price.

These are defined in the statement of the Energy Cost Target Modelling Methodology.

Chapter 7: Inertia Modelling

Rate of Change of Frequency

7.1 A large generation or demand loss on the system can cause the frequency to change at a fast rate. The Rate of Change of Frequency (ROCOF), is dependent on two factors:

- Size of generation/demand loss

System Inertia – A synchronous generating unit (mainly large steam or gas turbine generating plant) operating in the electrical power system will deliver its stored energy (in the rotating mass of the shaft of the turbine) to the system on falling system frequency. This inertia response will help to slow down the initial fast drop of the system frequency and hence help reduce the ROCOF and is measured in Hertz per second (Hz/s).

7.2 Some embedded generators are equipped with protection relays to prevent them generating as part of a non-viable isolated system. This Loss of Mains (LOM) protection is normally set to 0.125Hz/s.

7.3 The ROCOF of the transmission system needs to be limited to 0.125Hz/s at all times. If the frequency changes faster than this rate then potentially around 3GW of further generation susceptible to ROCOF could be tripped. This combination of effects will cause a rapid frequency drop which might be unrecoverable and thus lead to a system shutdown.

7.4 System inertia will reduce as a result of increasing the penetration of asynchronous generators, which have no or very little natural inertia compared to large synchronous generators (due to the absence of a large rotating mass in the generator). The degree of reduction is dependent on how much asynchronous plant is connected, and the generation output of this plant, which in turn determines how much synchronous plant is left running at any time. Over the 2013-17 period, the costs of managing ROCOF have increased significantly compared to the previous years, especially overnight and summer afternoons when demand is low and non-synchronous generation is high.

7.5 ROCOF can be managed by either instructing more machines on to the system, or reducing the size of the largest instantaneous loss on the system.

7.6 If, for the largest generator at risk on the system, we forecast a change in frequency greater than 0.125Hz/s, then the actions we would consider (in cost order) are firstly to reduce the size of the risk by reducing the output of the relevant generator, and secondly to synchronise additional machines to provide the required level of total system inertia.

7.7 There are also five generator groups where a credible loss on the transmission system could result in ROCOF exceeding the limit and so actions must therefore also be taken on these generator groups. These five groups and the generators which exist within these groups are shown in Appendix B. This could be because of a permanent network configuration, as is the case for Immingham, Seabank or the group made up of Saltend and the off-shore wind farms. Alternatively it could be because of an outage on the transmission system e.g. an outage on one of the Dino-Pentir circuits which results in Dinorwig being connected via a single circuit.

Modelling the Cost of System Inertia

7.8 Practically, it is not possible to model ROCOF costs in Plexos so a deterministic model has been developed to separately calculate a ROCOF cost target using outputs from the Plexos constrained run.

7.9 ROCOF costs are incurred as a result of either national requirements, where we maintain enough system inertia to respond to the largest credible loss or local issues which are resolved by reducing the outputs of key generators within generator groups. The model resolves national ROCOF through reducing the largest loss on the system, assumed to be the two IFA and one BritNed interconnectors, and the 5 generator groups rather than increasing system inertia.

7.10 Model validity is dependent on the option of trading on the interconnectors being available. If this becomes unavailable due to operational reasons or changes in legislation (European or other), NGET will revise the current methodology and submit to the Authority for approval.

Model Overview

7.11 The ROCOF model is the sum of the costs of reducing the largest loss and the cost of replacing that volume in the Balancing Mechanism.

7.12 A number of assumptions for the ROCOF model are detailed in Appendix C.

7.13 In the following model descriptions, ex-post inputs are coloured blue and ex-ante inputs are coloured red.

7.14 The ROCOF costs for each month will be calculated as follows:

ROCOF_C
= Reduce_Max_Loss_C + Replacement_Cost

Where
Reduce_Max_Loss_C is the cost of reducing the largest loss
Replacement_Cost is the cost of replacing that volume

Largest Loss Cost

7.15 The cost of reducing the largest loss is the monthly ROCOF volume multiplied by the price to reduce that volume.

Reduce_Max_Loss_C = BritNED_C + IFA_C + BM_C

BritNED_C = msum(IC_ROCOF_V_HH x BritNED_Sell_Price)
IFA_C = msum(IC_ROCOF_V_HH x IFA_Sell_Price)
BM_C = msum(BM_ROCOF_V_HH x BM_Sell_Price)

ROCOF Volume

7.16 The half hourly ROCOF volume model takes the constrained Plexos generation and calculates the largest loss for each half hour. This is then compared with the flows on the interconnector and the 5 generator groups to calculate when the interconnector or the generator groups is greater than the largest loss.

7.17 The total inertia available is calculated as the sum of the inertia provided by generation added to the inertia provided by demand.

7.18 The largest loss (MW) is calculated by dividing the total inertia by 200. Where any of the 5 generator groups have a combined volume above the largest loss, the difference between these is the half hourly bid volume required. Where the interconnector import flow is greater than the largest loss volume, the difference is the bid volume required. However, as interconnector trades can only be executed on an hourly basis the most onerous half hour is applied to both half hours.

For each Interconnector bipole (1 x BritNED, 2 x IFA):

IC_ROCOF_V_HH = max (0, Flow_HH – Largest_Loss_HH)

For each BM Generation Group (5):

BM_ROCOF_V_HH = max (0, Generation_HH – Largest_Loss_HH)

7.19 When trading for ROCOF on the interconnectors, these are carried out in 1 hour blocks. This has therefore been applied to the model such that for both half hours within the hour block the required volume for the hour is the higher of the two volumes. This is then rounded up to the nearest 5MW.

Sell Price

7.20 The sell price model for interconnectors uses a day ahead power price multiplied by a discount factor.

IFA_Sell_Price
= IFA_P_HH * 0.81

Where
IFA_P_HH power price at day ahead for the hour in which the half hour is contained.
0.81 is a discount factor to reflect the traded sell price on the interconnectors achieved by NGET

BritNED_Sell_Price
= BritNED _P_HH * 0.81

Where
BritNED_P_HH power price at day ahead for the hour in which the half hour is contained.
0.81 is a discount factor to reflect the traded sell price on the interconnectors achieved by NGET

7.21 The price which is used to resolve local constraints is taken from the most attractive bids prices across the generation group, which are used within Plexos.

For each BM Generation Group:

BM_Sell_Price = Plexos_P_HH

Replacement Cost

7.22 The replacement cost target is the volume required to reduce the largest loss multiplied by the energy reference price, this is then multiplied by an uplift factor to reflect the additional cost incurred for this balancing action.

Replacement_Cost

= msum (ROCOF_V_HH * ER_P_HH * ERP_Uplift)

Where

ROCOF_V_HH is the sum of the individual ROCOF volumes across interconnectors and BM groups

ER_P_HH is the energy reference price as defined in **10.20** of the Statement of the Energy Balancing Cost Target Modelling Methodology.

ERP_Uplift has been calculated as 1.48

Appendix A

High Cost-Low Volume Actions

A.1 The criteria below will be used to extract High Cost-Low Volume actions from monthly BOA files produced from the Plexos results files which identify the volume of Bid/Offer, the total costs as well as the price per MWh for every period the actions were taken on each generator:

i. All modelled bids accepted at price/MWh ≤ -£99995 from category Wind

ii. All modelled bids accepted at price/MWh ≤ -£99995 from Stevens Croft

iii. All modelled offers accepted at price/MWh ≥ +£99995 from Stevens Croft

iv. All modelled bids accepted on nuclear generators with price/MWh in the region of −£10000/MWh

v. All modelled offers accepted on nuclear generators with price/MWh in the region of +£10000/MWh

vi. All modelled bids accepted at a generator submitted[10] price ≤ -£9995 from any category excluding Nuclear

vii. All modelled offers accepted at a generator submitted[11] price ≥ +£9995 from any category excluding Nuclear

A.2 The criteria below sets out the replacement price for each of the above criteria:

Price Origin	Generator	Category	Substitute Bid Price	Substitute Offer Price
Defaulted	All	Non BM Wind	Volume weighted average bid price accepted on BM wind in the calendar month	N/A
Defaulted	Stevens Croft	Biomass	Treated in the same way as embedded wind.	The absolute value of the volume weighted average accepted wind bid price in the calendar month
Generator Submitted	All	Nuclear	-£~~500~~150/MWh	+£500/MWh
Generator Submitted	All	All categories except Nuclear	150% of the lowest, negative, non-zero, Bid price accepted for that period, irrespective of fuel type of generator. Note- if no bid accepted in that period then default to the preceding period which offers the relevant data to create a substitute price	150% of the highest, positive, non-zero, Offer price accepted for that period, irrespective of fuel type of generator. Note- if no offer accepted in that period then default to the preceding period which offers the relevant data to create a substitute price

[10] Generator submitted price includes those directly submitted as well as those determined from a price defaulting rule (as per the methodology) which incorporates this submitted price data

[11] Generator submitted price includes those directly submitted as well as those determined from a price defaulting rule (as per the methodology) which incorporates this submitted price data.

Appendix B:
Local RoCoF Groups

Dinorwig	Immingham	Saltend	Seabank	South Humber Bank
Dinorwig 1	Immingham	Saltend 1	Seabank Phase 1	South Humber Bank Phase 1
Dinorwig 2		Saltend 2	Seabank Phase 2	South Humber Bank Phase 2
Dinorwig 3		Saltend 3		
Dinorwig 4		Humber Gateway Offshore Windfarm 1		
Dinorwig 5		Humber Gateway Offshore Windfarm 2		
Dinorwig 6		Westermost Rough Windfarm		

Appendix C:

ROCOF Model Assumptions

C.1 A number of assumptions have been made regarding some of the inputs. These are described below:

i. The inertia requirement is calculated from the largest loss. Based on empirical data and power system equations, this is 200 times the largest loss. Therefore, for the assumed 1000MW loss, the inertia requirement is 200,000MVA (Inertia_Req_HH).

ii. Demand_Inertia_HH is demand multiplied by 1.86. 1.86 represents the ratio of inertia to demand.

iii. To calculate the replacement cost a discount factor is applied to the average overnight power sell price to incentivise NGETs trading strategy. This is set at 0.81.

Glossary

The following definitions are intended to assist the reader's understanding of this document. In the event of conflict with definitions given elsewhere, those used in the Transmission Licence, Grid Code, Balancing and Settlement Code and Connection and Use of System Code take precedence.

Term	Definition
BMU	Balancing mechanism units
CPN	Capped Physical Notification
Classes	Groups of Object types – e.g. Production class contains the Object types Generator, Storage, the Transmission class contains Lines and Nodes etc.
Ex-ante	Ex-ante data is data reflecting events that have yet to happen by the time of the beginning of the Scheme. By implication, such data has to be estimated or predicted.
Ex-post	Ex-post data is outturn data, i.e. data reflecting events that have happened by the time of the beginning of the Scheme.
FPN	Final Physical Notification
Memberships	A method to link two objects together. For example, a generator will have a membership to a fuel and a node.
MEL	Maximum Export Limit
MIL	Maximum Import Limit
Objects	Physical and financial features of electricity market – for example, Generator, Line and Company. They are defined by Properties, and their relationship to other objects is defined by memberships
Properties	They define an object. For example, a generator can be defined by a Max Capacity and a Heat Rate. It is typical for more properties to be used to define an object.
SRMC	Short Run Marginal Cost
SEL	Stable Export Limit
SIL	Stable Import Limit
VO&M	Variable Operation & Maintenance

Revisions

Issue	Modifications	Changes to Pages
1.0		