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Quality Assurance of CMP213 Modelling

This report has been prepared by Lane Clark and Peacock LLP ("LCP"). It is addressed to Ofgem and presents our QA findings on the models used for analysis of the effect of different options under the Connection and Use of System Code (CUSC) Modification Proposal 213 ("CMP213").

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Executive Summary

We have reviewed certain elements of the CMP213 modelling and have found no issues with the implementation of the agreed methodology that we believe would materially affect the conclusions reached from the modelling results.

We have found some issues with the implementation, which we have outlined in this report, but we do not believe that these issues should fundamentally affect the main modelling results.

To reach these conclusions we have reviewed key calculations within the models through a combination of code/formula review, result replication and sensitivity analysis. We cannot guarantee that the model will produce correct results under all conditions, particularly if the data set was to change significantly.

Although, as requested, the focus of our review was on the implementation of the model methodology, we have also been asked to provide a high-level view on the model methodology itself. The principal question that the modelling is attempting to answer is a challenging one: how will changes in transmission charging affect investment, retirement and dispatch decisions? Our view is that many key results are being influenced by modelling simplifications and this should be taken into account when drawing any conclusions based on the results of the analysis.

In the appendix of this document we have provided an issues log of the minor issues that relate to the implementation of the methodology that we found during our review. This log contains a description of each issue, the implications and a suggested action where appropriate.

1. Background

Project TransmiT was established by Ofgem to review the charging arrangements for transmission networks. In May 2012 Ofgem published the results of its Significant Code Review (SCR) which concluded that industry should develop an improved version of the current Investment Cost Related Pricing (ICRP) for calculating Transmission Network Use of System (TNUoS) tariffs. That report used analysis based on a model methodology developed by National Grid Electricity Transmission (NGET) and Redpoint Energy (now a business of Baringa Partners LLP) that provides a quantitative assessment of the cost benefit characteristics of different charging options.

The Improved ICRP involves enhancements to the current ICRP methodology to include a year-round charge as well as a peaking element which is designed to better reflect the costs that are imposed on the transmission network by different generators.

Over the past 12 months industry participants have been working on preparing the Connection and Use of System Code (CUSC) modification proposals which contain NGET's "Original Proposal" along with 26 alternatives relating to varying the treatment in three main areas:

- **Shared transmission capacity**

  Different options for the accounting of the Main Interconnected Transmission System (MITS) within a year round tariff, including a possible split into a shared and non-shared component. Also variations of the diversity calculations based on the relationship between the level of low-carbon and carbon generation and the method for calculating the incremental investment costs.

- **Treatment of HVDC links**

  Options as to which of the investment costs associated in the development of HVDC links are included in the expansion factor (unit cost) calculation, in particular the removal of all or some of the converter costs, such as the elements similar to AC substations and Quadrature Boosters.

- **Sub-sea island links**

  Options as to whether all or some of the converter costs could be socialised, such as removing elements similar to AC substations and Voltage Source Converters (VSC).

Seven of the 26 alternatives and the original proposal have been modelled by NGET using updated versions of the models used for the SCR report (plus the current charging methodology with changes to island and HVDC links).

1.1. Overview of the modelling approach

The modelling of the CMP 213 options combines together three models:

- The TransmiT Decision Model (TDM) – This model was developed by Baringa and acts as the engine for the modelling and controls the other two models. It calculates investment decisions in new plant and constructs the merit-order stack.
- The Transport and Tariff (T&T) model – This model was developed by National Grid and calculates the tariffs that apply. A different version of the model exists for each of the CMP213 options being considered as well as the status quo.
- The ELSI model – This model was developed by National Grid and is capable of performing dispatch allowing for network constraints. This allows it to calculate the constraint cost which is then used to determine investment in network reinforcement. ELSI is also used to calculate generation and income for each unit.

Each of these models has been implemented within Excel using a combination of VBA code and standard Excel formulae. There is also an associated Transport Model Interface Spreadsheet which passes information from the TDM to the T&T and vice versa.

1.2. Scope of our review

The scope of LCP's review was to check that:

- The calculations in the TDM are being performed as intended and in line with the agreed methodology. In areas where a formal methodology is not available we outline the calculation being performed and provide our view on the reasonableness of the approach in the light of the wider modelling intentions.
- Updates made to the T&T model for each of the different CMP213 options have been implemented as intended and in line with the agreed methodology.
- The additional functionality that has been added to the ELSI model in order to make investment decisions in network reinforcements has been implemented as intended.
- The links and data mappings between the models have been implemented as intended.
- The input data has been entered and used as intended where it has come from a public source. Where input data has not come from a public source we provide an order of magnitude check on the reasonableness of the inputs.
- The outputs produced by the model have been calculated in line with the agreed methodology. Where no formal methodology was available we check that the approach taken and the order of magnitude of the outputs are reasonable.

2. Review of the TDM

2.1. Approach to the review

LCP has analysed the TDM using two approaches.

For code and spreadsheet formulae that were available for review, we have outlined the calculation that is being performed and our conclusion as to whether we believe the approach to be reasonable and/or correct.

Some areas of the TDM were not available for review due to intellectual property rights. For these areas of the modelling we have conducted high-level sensitivity analysis on the main inputs.

2.2. Interaction of the TDM with the other models

We have reviewed how the TDM manages the relationship between the three models and the data flows between these models. An overview of the simulation loop performed by the TDM can be found in Appendix 2. A summary of the data flows between the TDM and the other models can be found in Appendix 3.

2.3. Internal calculations within the TDM

In addition to managing the modelling process the TDM performs a number of the key calculations of the model. The vast majority of these are performed through excel formulae but some operations are conducted within VBA code.

Here we set out our review of the internal calculations within the TDM model. As there is not a detailed specification of the model we have provided an overview of the calculation (found in the Appendix A2) alongside the results of the review.

The sub-sections below reflect the structure of the model, each representing a different worksheet (that is, each sub-heading below is the tab name of a worksheet within the spreadsheet).

2.3.1. MAR Calcs

Purpose of the calculation

This worksheet calculates the base Maximum Allowed Revenue (MAR) for each year. After additions for offshore and island project cost, the Final MAR value is used in the T&T model as the "Total Infrastructure Revenue" target. After the Generation/Demand split is determined, all tariffs are adjusted by a Residual in order to achieve this total revenue target. A more detailed overview of this calculation can be found in Appendix 4.

Result of the review

Our review gives us no reason to believe that this calculation is being performed incorrectly.

2.3.2. Low carbon build

Purpose of the calculation

The low carbon build spreadsheet calculates support levels and related metrics for low carbon generators. An overview of this calculation can be found in Appendix 4.

Result of the review

We have reviewed each of these calculations and can confirm that they have been performed as intended.

Note that for plant receiving a CfD the reference price is expected to be the year-ahead wholesale price for baseload plant and the day-ahead hourly price for intermittent generators. The model uses the LRMC of a new build CCGT as an approximation to a baseload power price for when calculating a plant's SRMC. This is a reasonable approximation for this purpose. This approximation is not used when calculating the plant's gross margin.

2.3.3. Annual costs

Purpose of the calculation

This calculates the LRMC for each plant and potential plant. A more detailed overview of this calculation can be found in Appendix 4.

Result of the review

We have reviewed each of the metrics and have found no issues with any of the values calculated above.

The LRMC calculations above are based on the assumption that the plant runs at baseload. However, the LRMC values have little effect on the modelling and are not used widely in any other calculations.

2.3.4. E_StackSpec

Purpose of the calculation

This worksheet calculates the available capacity and SRMC of plant in each year. This is the first stage of creating the merit order stack. An overview of this calculation can be found in Appendix 4.

Result of the review

The calculation of the SRMC had incorrectly referenced the range for fuel transport costs. This led to the SRMC of coal plant being £2 - £3 lower than intended. However, we do not believe that this should have a material effect on the conclusions drawn from the modelling results.

All other calculations are being performed as expected.

2.3.5. E_Supply curves

Purpose of the calculation

This calculation takes the SRMC's and capacities above to generate a high availability and low availability stack in each season.

The ELSI model assumes that the availability of generators is constant across each season. To allow for different availabilities within a season, two merit order stacks are calculated: High availability and Low availability. This allows the running regime of plant constrained by IED/LCPD to be approximated in the ELSI dispatch modelling.

The model is parameterised so that the high availabilities apply to the x% of periods with highest demand.

A more detailed overview of this calculation can be found in Appendix 4.

Result of the review

For plant assumed to fit SCR the limited winter load factor is still applied, leading to higher summer availabilities than winter availabilities. This only affects one plant so we do not view it as having a material effect on the results. We would however recommend that this is updated in future analysis.

For three plant (c3.3GW of capacity) the limited load factors have not been applied in the low availability stack. We would recommend that this is updated in any future analysis.

All other calculations above are being performed as we would expect.

2.3.6. E_PowerPriceCalcs

Purpose of the calculation

This worksheet is where the power price is calculated in each of the 100 sample demand periods. In the CMP213 modelling ELSI is used to calculate the dispatch decisions so we have not reviewed the formulae relating to dispatch decisions.

2.3.7. E_PlantWiseGenResults

Purpose of the calculation

This worksheet calculates the profits of individual plant and the clearing prices of the capacity auction. An overview of this calculation can be found in Appendix 4.

Result of the review

Gross margin for CfD plant is calculated based on the assumption that these plant receive the CfD strike price for each MWh of generation. This is correct under the assumption that the plant run as baseload and that the year-ahead base load price is equal to the outturn baseload price. This is a reasonable assumption for the purposes of this modelling exercise.

2.3.8. Capacity mechanism

The formulae that govern the capacity mechanism were not available for review so we have conducted high-level sensitivity analysis on the main inputs based on our understanding of the calculation being performed. Details of this high-level sensitivity analysis can be found in Appendix 4.

We confirm that the clearing prices of auction are broadly consistent with what we would expect and are consistent with the plant clearing the auction in each year. We note that the margin targeted by the mechanism is not always met due primarily to discrepancies between the clearing of the auction and new build/closure decisions. This should be considered when interpreting the results of any analysis in particular those relating to capacity margins.

2.3.9. Investment and retirement decisions

Many of the formulae related to investment and retirement decisions were unavailable for review. In order to test these areas of the model we have performed high level sensitivity analysis.

The main drivers of the build decisions that are not covered by our review of plant revenues are Capex assumptions and build limits. Details of the sensitivity analysis run can be found in Appendix 4. In all the tests run the model behaved as we would expect.

3. Review of reinforcement decisions within ELSI

3.1. Overview of the modelling methodology

The ELSI model is primarily a constraint dispatch model. It simulates plant dispatch both with and without network constraints in order to determine the constraint cost. This constraint cost calculation is part of the core functionality of the ELSI model and is outside the scope of our review.

For the purposes of TransmiT modelling Baringa has added functionality to the ELSI model that allows it to make investment decisions in network reinforcements. This is done by adding reinforcement to the ELSI input network and calculating the resultant reduction in constraint cost. By comparing this to the levelised cost of the reinforcement an investment decision can be made. An overview of the calculation can be found in Appendix 5.

3.2. Result of our review

Our review has found no fundamental errors in the code that controls the interaction with ELSI or the excel formulae that determine the projects to be considered.

We would however recommend that implementation of this area of the model is revisited if the model is to be used again in future. This is for the following reasons:

- It is necessary for this code to interact with an existing model (ELSI). As a consequence the VBA code interacts heavily with the spreadsheet, and there is therefore a significant risk that changes to the spreadsheet will have unintended consequences on the operation of the VBA code.
- The relationship between the spreadsheet formulae and the VBA code is not clear without extensive study of the VBA code. This should be clarified in the worksheets to show where the VBA code is reading in and writing out data.
- Certain areas of the code are based on fixed parameters, for example the code assumes that the model has a start date of 2011, whilst the excel formulae that rank reinforcements are based on exactly 67 reinforcements.
- The size of the VBA macros makes review and checking difficult, and they should ideally be split into smaller separate functions. This will also help avoid the need for repeated code, for example the code above for reinforcements only available in Y + 5 is almost identical to the other reinforcement decisions. This could be parameterised to significantly reduce the code complexity and likelihood of errors.

4. Review of Transport and Tariff model

4.1. Approach to the review

LCP has analysed the Transport and Tariff (T&T) model using two approaches.

Where practical, we have replicated the results produced by the model using equivalent calculations.

In cases where this was not practical due to the complexity of the calculation, we have reviewed the VBA code and checked the results for reasonableness. Where relevant we have checked that the approach used is in line with the formal specification.

Some areas of the T&T model were outside the scope of this review as they had not been updated in the modelling of the CMP213 options. In particular, the DC Load Flow (DCLF) algorithm was outside the scope and not reviewed.

4.2. Overview of the T&T model review

In this section we outline the areas of the T&T model covered by our review and the approach used to verify the results for each.

Model area	Description	Approach used	Model versions that contain this calculation
Nodal calculations	Bus Ordering, Phase angles	Not reviewed, outside scope	All, ie Status quo, Original, Diversity 1, Diversity 2, and Diversity 3.
Line flows	Power flows on the network, calculated by DCLF algorithm.	Not reviewed, outside scope	All
Line flow costs	Cct flow "cost"/MW and Total Cct Flow Cost (Wider and Local) derived from the line flows and expansion factors.	Replicated results for all lines	All
Nodal marginal costs	Demand, Wider and Local marginal costs. Increase in cost that results from +1MW of additional generation at the node.	Replicated results for selected nodes by perturbing and re-running the DCLF	All
Gen Low Carbon-Carbon split	Total Low carbon and Carbon capacity (TEC) by zone.	Replicated results for all zones	Diversity 1, 2 and 3.
Diversity method	For methods 1, 2 or 3, the zonal sharing ratio used.	Replicated results for all zones	Diversity 1, 2 and 3.

Model area	Description	Approach used	Model versions that contain this calculation
Tariff results	Final tariffs for Demand (Peak and Year Round), Zonal Generation (Peak and Year Round) and Local Asset generation.	Replicated results for all demand zones, generation zones & local assets.	All (though not all versions calculate all tariffs, eg Diversity 3 does not have Peak tariffs)
HVDC	Calculates the HVDC line impedances, which are an input to the line flow calculation.	Reviewed VBA code, spreadsheet formula and checked results for reasonableness. Replicated parts of the calculation, eg the “Desired Flow”. The “Fast DCLF” algorithm’s line flow results were verified by comparing results against the original DCLF algorithm.	All
Interaction with the T&T interface	Input data is uploaded from the interface to T&T model, T&T model then sends back the final tariff results.	Reviewed that the inputs were being uploaded correctly and that the correct final tariffs are being picked up.	All

In the following sub-sections we provide further detail on the review carried out for each of these model areas.

4.3. Line flow costs

Purpose of the calculation

The line flow unit costs (Cct flow "cost/MW”) are applied within the VBA code to calculate the nodal marginal costs. They are reported in the transport results along with the total line flow cost, which is the unit cost multiplied by the line flow.

Our approach

We replicated the results produced by the VBA code using spreadsheet calculations, for both the wider and local costs. This was simply:

- Cct_flow_cost_per_MW = (OHL_Length x Line_ExpansionFactor)

  + (Cable_Length x Cable_ExpansionFactor)

- Total_Cct_flow_cost = Cct_flow_cost_per_MW x LineFlow

Note that absolute values are used for all Line Flows, ie the direction has no bearing on the associated cost.

Result of our review

Our review verified that all the line flow costs have been correctly calculated.

We would however recommend that an adjustment is made to the total line flows (“Total cct flow costs”) so that they are not rounded to the nearest integer. The rounded results are reported but are not used in the final tariff calculation so this issue is not material.

4.4. Nodal marginal costs

Purpose of the calculation

The nodal marginal costs are the key output of the transport modelling and are the basis for deriving the TNUoS tariffs.

The nodal marginal costs are calculated in VBA code, and each node's marginal cost represents the total additional cost to the system when 1MW of generation is added at that node. In each calculation, a corresponding 1MW of demand is distributed amongst all nodes, based on their existing share of total demand. This approach is known as a "distributed reference node", and differs from the status quo, which uses a single reference node. Due to this change, and the addition of dual backgrounds (peak and year round), it was necessary to review the marginal cost results.

Our approach

We replicated the results for selected nodes using the following steps:

- We ran a "basecase", and recorded all the nodal marginal costs, line flows (peak and year round) and unit line flow costs (wider and local).
- We ran a "+1MW" sensitivity with a small amount of additional generation (1MW or less) added to the selected node and an equal amount of demand distributed amongst all the nodes based on their share of total demand.
- We recorded the line flows (peak and year round) for the "+1MW" sensitivity.
- We calculated the marginal cost for the node selected, using the following calculations:

$\text{MC\_Demand}_{\text{NodeA}}$ = Sum across all lines:

$$[\ (\text{LineFlow}_{+1\text{MW}} - \text{LineFlow}_{\text{basecase}}) \times \text{Cct\_flow\_cost\_per\_MW}_{\text{Wider}}]$$

$\text{MC\_Wider}_{\text{NodeA}}$ = Sum across all lines that are not in the same local grouping as node A:

$$[\ (\text{LineFlow}_{+1\text{MW}} - \text{LineFlow}_{\text{basecase}}) \times \text{Cct\_flow\_cost\_per\_MW}_{\text{Wider}}]$$

$\text{MC\_Local}_{\text{NodeA}}$ = Sum across all lines that are in the same local grouping as node A:

$$[\ (\text{LineFlow}_{+1\text{MW}} - \text{LineFlow}_{\text{basecase}}) \times \text{Cct\_flow\_cost\_per\_MW}_{\text{Local}}]$$

Note that absolute values are used for all Line Flows, ie the direction has no bearing on the associated cost. For Demand and Wider, separate marginal costs for the peak and year round backgrounds are calculated under most options (Original, Diversity 1 and Diversity 2). The marginal costs for peak are calculated as above but by only summing the additional costs where the peak flow is greater than the year-round flow (in absolute terms), and vice versa for the year round marginal costs. This is known as circuit "binning" and adds an investment driving criterion to each line.

Result of our review

Our review verified that the nodal marginal costs were being calculated correctly.

We replicated the marginal cost results for selected nodes, which were chosen in order to cover different combinations, in particular nonzero local marginal costs that have different unit costs to the wider network (so that the results for Wider plus Local did not equal Demand). In addition, the code was reviewed with particular attention paid to the sections where the methodology had changed. A summary of the tests conducted can be found in Appendix 6.

4.5. Diversity method (including Low Carbon-Carbon split)

Purpose of the calculation

For each of the diversity options, a calculation is made to determine the shared/non-shared split for each zone's year round marginal costs. The sharing calculations are based on the ratio of low carbon to carbon generation.

In Diversity options 2 and 3 the minimum of the proportion of low carbon and the proportion of carbon generation behind the boundary (ie a max of 50%) is used as the sharing %. For Diversity option 1, all costs are shared for low carbon / carbon ratios below 50%, and then sharing reduces from 50% to 100% low carbon.

For Diversity options 1 and 2 the shared portion of the marginal costs is charged based on generator load factors, whereas the non-shared portion is charged based on capacity. For Diversity option 3 only the non-shared portion is charged, and this is based on capacity only.

Our approach

We replicated the zonal results for all three diversity methods using spreadsheet calculations.

Result of our review

Our review verified that the sharing methods for Diversity options 1 and 2 were being applied correctly and the final results were correct.

For Diversity option 3 there was a material error found in the Zonal Sharing Factor (ZSF) calculation. In the testing data provided, this only affects the ZSF for zone 15, meaning its ZSF is -15% rather than 215%. This would mean the final YR wider tariff for Z15 is £1.05 too low, and all other zones £0.10 too high. A numerical example outlining the error in more detail can be found in Appendix 7.

NGET has confirmed this is an error and was not intentional. The error has been corrected and the Diversity 3 analysis has been rerun. The impact on the final results was not of great significance at the GB level. However, there were some significant impacts at the regional level, particularly in later years, including a change in the locality of nuclear build in 2026. We believe this reflects the sensitivity i of the overall modelling to input assumptions in this case, and do not believe this should materially affect the conclusions reached from the analysis.

We also found one small error in Diversity option 2, with the "Max Sharing" value for Zone 6's Z5 value being incorrectly calculated as 44% rather than 0%. As this value is applied to a zero marginal cost the error is not material and does not affect the final results.

We would recommend that the spreadsheet formulae on the “Gen Low Carbon-Carbon split” and “Method x” sheets are updated to fix this immaterial error and to ensure the calculations are robust under situations where the Transmission network changes. See issues log in Appendix 1 for more detail.

4.6. Tariff Results

Purpose of the calculation

The tariff results are the ultimate output of the T&T model. Tariffs are produced for demand, zonal generation and local generation, with both year-round and peak tariffs in some options. They are calculated based on the marginal costs produced by the transport model and the sharing/non-sharing split produced by the diversity calculation.

Our approach

We replicated the results produced by the model’s VBA code and spreadsheet calculations using our own spreadsheet calculations, for all tariffs and all model versions. This included the zonal marginal costs that are produced by VBA code using the results of the transport model run.

Result of our review

Our review verified that all the tariffs have been correctly calculated.

We would however recommend that some minor fixes are made to the models, such as ensuring all headings are correct and consistent, and removing redundant data. See the issues log in Appendix 1 for more detail.

4.7. HVDC

Purpose of the calculation

The HVDC calculation provides the impedances for the HVDC bootstraps modelled in the transport model. These are calculated iteratively using a pared down version of the DCLF algorithm, known as the “Fast DCLF” algorithm. The HVDC desired line flows are calculated to target the same ratio of flows as the ratio of capacity provided by the HVDC link relative to the capacities on all major transmission system boundaries that it parallels.

Our approach

We replicated the inputs calculated for the iterative algorithm, and checked the results from the iterative algorithm were reasonable. We also reviewed the VBA code and that the methodology used was appropriate.

Result of our review

Our review verified that there are no significant issues with inputs to the iterative algorithm and that the resulting HVDC impedances are reasonable.

In the input checks we verified that:

- The Fast DCLF power flow algorithm produces the same line flow results as the original DCLF algorithm.
- The boundary flows and ratings are calculated correctly.
- The desired flows are calculated as intended. Note that in this calculation zero flows are assumed on other HVDC lines (but nonzero capacities), which is correct at the start of the iteration, when all HVDC flows are set to zero.

We have concluded that the iterative algorithm produces reasonable results.

We would recommend some minor enhancements to the usability and transparency such as allowing the user to define parameters such as the number of iterations, initial step-size and tolerance level. See the issues log in Appendix 1 for more detail.

4.8. Interaction with the T&T interface model

Purpose of the calculation

The T&T interface model provides the T&T model with its input data, including data for the wider buses and circuits, the local buses and circuits, the HVDC boundaries, transmission project data, the final Maximum Allowable Revenue (MAR) and the Generation/Demand split for MAR.

The T&T interface model then runs the HVDC, transport and tariff macros and picks up the final tariff results.

Our approach

We checked that the correct input data was being referenced and uploaded for each year and that the interface was picking up the correct final tariffs.

Result of our review

Our review verified that the T&T interface was providing and then picking up all data correctly.

We would however recommend that a small adjustment is made to ensure this process is made more robust. If the T&T model contains no data, then the input data is pasted incorrectly (one row too high, overwriting the headings).

5. Review of input data and assumptions

We have reviewed the main input assumptions and data items used within the modelling and found no significant issues. An overview of the items reviewed, including the location in the models, the source used and the results of our review can be found in Appendix 8.

6. High-level comments on CMP213 methodology

In addition to our review of the implementation of the CMP213 modelling we have also been asked to provide a view on the model methodology. We note that some of the details below were agreed with the TransmiT technical work group.

With any model of this type there is a need to balance model complexity with practicality and all our comments should be viewed in this light. The principal question that the modelling is attempting to answer is a challenging one: how will changes in transmission charging affect investment, retirement and dispatch decisions? These decisions are strongly driven by macroeconomic conditions and the evolving policy environment, and the CMP213 results should be viewed in this context.

In particular, the modelling of EMR will play a fundamental role as the capacity mechanism and Contracts for Difference (CfDs) will, between them, drive the majority of investment decisions in new generation capacity – the CMP213 transmission pricing drivers could therefore easily be “swamped” by the EMR drivers.

We discuss the capacity mechanism and contracts for difference in more detail below.

6.1. The capacity mechanism

The design of the capacity mechanism has evolved during the CMP213 modelling work, and understandably a simplified version of the mechanism has been implemented within the modelling.

In particular, when the capacity mechanism is in operation (with the first delivery in winter 2018-19) it will drive the majority of investment that is not directly supported by CfDs. The mechanism will therefore determine the level of system security in GB, and any changes in the underlying economics of plant are likely to be reflected in the clearing price of the auctions rather than in capacity margins. For this reason we would not expect there to be any fundamental differences between CMP213 options in terms of GB-wide system security.

Within the CMP213 modelling the build and retirement decisions are not directly determined by the operation of the capacity mechanism. This can cause a potentially significant divergence between the targeted capacity margin and the realised margin within the modelling.

Any modelling results that show varying capacity margins are therefore predominantly a reflection of the way that the capacity mechanism has been modelled and should not be seen as a potential advantage or disadvantage of any of the CMP213 options being considered. For this reason we would recommend that the capacity margin metric is used for model diagnostics only, and not for reporting and analysis.

There are also certain secondary effects that should be taken into account when analysing results. Notably the varying capacity margins will also change the uplift applied to system prices when calculating the wholesale price. The uplift applied is parameterised based on the capacity margin and so any changes in the margin will lead to potentially significant changes to the wholesale price. For the same reason as above we would not expect the uplift to change based on differences between the CMP213 options once the capacity mechanism is in force.

6.2. Contracts for Difference (CfDs)

Under CfDs a strike price for each technology will be determined that provides a subsidy for investment in low carbon generation. Initially the subsidy levels will be set administratively at a level chosen in order to target a given level of overall investment in low carbon generation.

Any changes to the cost of generation investment will require higher or lower strike prices to be set in order to achieve the same renewable targets. For this reason any changes to charges applied to renewable generators is likely to mean that higher or lower support levels are required in order to achieve the same level of renewable investment.

There are different approaches to determining what strike prices should be used in modelling. One method is to minimise cost by supporting the cheapest new build options until a build limit is hit for that technology. Without detailed supply curves or restrictive build limits this can lead to a generation mix that is not very diverse.

Within the CMP213 modelling the strike prices have been chosen to achieve a diversified generation mix that meets the required renewable and decarbonisation targets. If the build constraints of each technology are not being hit then there are multiple combinations of strike prices that can be chosen to achieve different diverse generation mixes.

When a change is made to the underlying cost of the build options (e.g. through changes in transmission charging) the build decisions will change and no longer meet the renewable targets. We understand that the approach for the CMP213 modelling has been to then update the strike prices so that the targets are still met.

In updating the strike prices a decision is being made on the composition of the generation mix, eg deciding whether to update the onshore wind or offshore wind strike price. As the original strike prices have been chosen to achieve a diverse generation mix, the change in generation mix becomes a modelling assumption rather than an emergent property of the modelling. Any attempt to quantify the change in the build of one technology against another is therefore likely to be swamped by the assumptions made on CfD strike prices.

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We accept no liability to any third party to whom our work has been provided (with or without our consent), unless the third party has asked us to confirm our liability to them, and we have done so in writing.

Appendix

A1. Issues log

#	Issue	Rating	Location	Comment	Resolved?
1	Diversity method 3 calculation for ZSFs is incorrect. Affects Zone 15 result in 2012/13.	Amber	**TT Diversity method 3 v5:** Method 3 tab	The formulae in cells C8:C27 of Method 3 (ZSF calculation) should not be subtracting the **absolute** value. As a result ZSF for zone 15 is -15% rather than 215% for the data supplied for testing.	NGET has confirmed this is an error and was not intentional. The Diversity 3 analysis has been rerun with this error corrected.
2	The calculation of the SRMC of each generating unit within the TDM had not picked up fuel transport costs.	Amber	**TDM:** E_StackSpec	This leads to the SRMC of coal plant being £2 - £3 lower than was intended in all years.	
3	For three plant (c3.3GW of capacity) the limited load factor factors have not been applied to the low availability stack.	Amber	**TDM:** E_SupplyCurves	If this was updated it would result in slightly higher prices in summer months which could have a minor knock on effect on other variables	
4	For plant that fit SCR the maximum winter load factor is applied meaning that availability is higher in summer that in winter	Amber	**TDM:** E_SupplyCurves	Only affects one plant but would lead to slightly lower winter prices and slight higher summer prices.	
5	Max Sharing for Zone 6's Z5 value is incorrect. Should be 0% not 44%. Does not affect final results, as is multiplied by the zero incremental km value when calculating shared zonal MC.	Minor	**TT Diversity method 2 v3 :** Method 2 tab	This is due to lots of manual formulae which are open to error. Suggest error is corrected, but also formulae are made more robust.	

#	Issue	Rating	Location	Comment	Resolved?
6	Version of original T&T interface file provided would not run: Type mismatch error in Private Sub ClearTransportModel().	Minor	**T and T Model interface Original v13:** ClearTransportModel sub	By overwriting with amended code from the diversity1&2 version, we were able to fix this. *If Application.WorksheetFunction.IsError(Range("Boundary" & i & "_Desired_Flows").Cells(1, 1).Offset(1, 0)) Then ...* This fix needs to be made in all versions of the interface file.	NGET confirmed this was a known issue and subsequent versions of Original model version needs updating.
7	Total cct flow cost is reported as a rounded value. Uses full precision when calculating marginal costs, so this is not material.	Minor	**TT model:** DCLoadFlow module, sub "*calccctFlow*"	"Dim clctotcctflow As Long". Ideally, this should not be an integer. These outputs are useful when reviewing marginal cost calculation (though can be easily derived from the spreadsheet.)	
8	Column headers on the transport tab do not provide units or descriptions.	Minor	**TT model:** General, Transport tab	This sheet would be made clearer and easier to follow if each column header provided the units & a short description. e.g. "Scenario 1 Demand" is a marginal cost, in MWkm, but this is not clear.	
9	When results in transport tabs are pasted in by the macro, can be pasted in incorrect location if columns / rows have been added by the user.	Minor	**TT model:** Transport tab	Suggest this process is made for robust in the future.	
10	There is no detailed documentation for the HVDC iterative calculation	Minor	**TT model:** HVDC	Suggest user guide is updated to include HVDC calculation.	
11	To get desired flow: ratio of flows = ratio of ratings. Where: ratio of ratings = HVDC1_rating/(Total_ Boundary_rating + Total_HVDC_Rating_including_HVDC1) ratio of flows = HVDC1_flow/(Total_Boundary_flow) Seems inconsistent to include ratings of other HVDC lines but not their flows.	Resolved	**TT model:** HVDC tab	Initial flows on the HVDC lines are zero, so this is correct given the basecase starting point	

#	Issue	Rating	Location	Comment	Resolved?
12	There are a number of hardcoded parameters in the HVDC module: - HVDC reactance step size = 2 - Max HVDC iterations = 60 - Resets starting points on iterations 42,62,82 - Tolerance starts at 20, goes in steps of 20, Max of 200.	Minor	**TT model:** HVDC module	Suggest these values are user options. This would improve usability and transparency.	
13	If a single HVDC line "fails", i.e. reaches max iterations (60) without finding a solution inside the tolerance, the model increases the tolerance for **all** the lines, and starts again	Resolved	**TT model:** HVDC module	This will result in worse results than those already found for some lines. e.g. Original v8, on first run through HVDC5 has flow of -592 (-588 desired), but HVDC 6 failed -658 (-516 desired). Final results are -631 and -457. I think would do this rerun even if HVDC6 was within new +-40 tolerance (eg HVDC6 had been -550). Suggest exploring approach where just increasing tolerance for the line that has no solution (HVDC 6), in first instance.	NGET has explored this approach but found it often resulted in the algorithm being unable to find feasible solutions for all the HVDC circuits.
14	Multiple subroutines that do very similar things, but only one is used: - Calculate_HVDC_X - Calculate_HVDC_X2 - Calculate_HVDC_X23 - Calculate_HVDC_X_Original Appears that only HVDC_X2 is used	Minor	**TT model:** HVDC module	Confirmed that only HVDC_X2 is used. Suggest that the other redundant subs are removed, archived or clearly labelled.	NGET Confirmed that only HVDC_X2 is used.
15	Macro does always clear all existing link results when running Transport results	Minor	**TT model:** Transport tab, DCLF module	Suggest this is fixed so it clears all previous results.	
16	Formula on "Gen Low Carbon-Carbon split" tab and "Method x" tabs are not robust and could cause manual errors. They will also produce incorrect results with a different set of Tx network data. (**See amber issue 3)**	Minor	**Diversity 1,2 and 3:** Method & Gen Low Carbon-Carbon split tabs	Suggest formulae are made more robust.	

#	Issue	Rating	Location	Comment	Resolved?
17	Error in draft legal text on page 95 and 176 of http://www.nationalgrid.com/NR/rdonlyres/631B8FB3-84D1-4D32-9F35-79E66AE06832/60060/WRVol4_FinalCAConsultation_V10.pdf. Should be summing SBI, not NSBI for the shared component in 14.15.47	Out of scope			
18	Generation total in diversity 3 for peak is referencing incorrect rows. Value is actually undefined, as diversity 3 has no peak background.	Minor	**TT Diversity method 3 v5:** Tariff tab	Remove values so as not to cause confusion. Sums over wrong number of rows which is dangerous for any future versions.	
19	Tariff results off to the right on the "Tariff" sheet do not seem to be used and in some cases are incorrect/mislabelled.	Minor		Remove anything that is redundant and correct the labels.	
20	Column AB on tariff sheet labelled incorrectly as "Peak Security Zonal Tariff (£/kW)"	Minor	**D1 and D2 T&T models:** Tariff tab	Should be final tariff. Column AC should be "pre-sharing"	
21	D27 on tariff sheet labelled as "Year Round Tariff (£/kW)", rather than "Final…".	Minor	**All T&T models:** Final Tariffs tab	Potential to cause confusion, as this already includes residual. Suggest this is made clearer.	
22	Headings are wrong on cells I123 and J123 in D1&2 tariff sheet, these are shared component, NOT final. Final tariffs sheet is correct.	Minor	**D1 and D2 T&T models:** Tariff tab	Suggest these are updated.	
23	Interface spreadsheet macro breaks if you don't already have a "/Results" folder	Minor	Interface files	Recommend this is created automatically if directory doesn't already exist (or user specifies a directory).	
24	Interface spreadsheet for diversity 3 has multiple tariff macro options, unlike the other files that have a single tariff macro. "Socialised" doesn't appear to do anything. "SQ + Socialised" & "LMP" same as "Status Quo" but don't pick up the generation tariffs correctly (all picked up as zero).	Minor	D3 Interface file	Baringa have noted that these are the previous policy options from TransmiT. These are not used in the CMP213 modelling. Suggest this is combined into one macro button, removing those that are redundant, as has been done for other model versions.	
25	"Output2" sheet in Original T&T model has errors. Isn't used by the interface so this is not material.	Minor	**Original T&T model:** Output2 tab		

#	Issue	Rating	Location	Comment	Resolved?
26	If the transport tab has no data (all blank), when interface pastes in the bus & node data, the first row is pasted over the headings. Needs at least one row of data already in there	Minor	**Original T&T model:** Output2 tab	Either adjust code to paste one row further down when blank data, or provide warning.	
27	The filenames for the T&T model result files produced by a full TDM are incorrect for the +5 year files	Minor	**TDM:** VBA code	Updating to the "Year_5" filename is triggered by event 109, when it should be 110.	
28	On the interface spreadsheet, "Control" tab, 2015-16 picks up data from the 2014-15 sheets (for bus, network, etc), even though there are sheets for 2015-16 in the file. All subsequent years will also pick up the 2014-15 data.	Resolved	**Original T&T model:** Output2 tab	The updated 2015-16 was not available at the time the modelling was done, the latest year of up to date data was 2014-15 so this was used. We recommend that the model is updated to incorporate and use up to date 2015-16 data in future runs.	Yes, see comment.
29	Unclear where Local substation tariffs are sourced from.	Minor	**Original T&T model:** Output2 tab	These values that are not changed by the macro, source should be documented / made clearer.	
30	The total Capex for the modelled projects, The Opening RAV and the pre RIIO Capex are linked to a spreadsheet on a user's local machine.	Minor	**TDM:** MAR Calcs	These links should be removed to avoid the external link and to provide a source for that data item.	
31	Use of VLOOKUP formulae	Minor	Throughout the T&T models and the ELSI spreadsheets	Modifications to these spreadsheets are highly likely to introduce errors. These should be converted to INDEX(MATCH()) formula.	
32	Use of IFERROR formula	Minor	TDM	These need to be used carefully as they potentially hide unintentional errors in the spreadsheet rather than the particular error they are designed to pick up	

#	Issue	Rating	Location	Comment	Resolved?
33	Inconsistent referencing of ranges within VBA	Minor	TDM	Ideally the VBA code would refer to a known range in a consistent way throughout. eg the "Current_Year" named range is referred to by the name, while other are not. Using a global name variable is preferable to a literal reference such as "J40".	
34	File naming of the T&T model runs for Y+5 is incorrect when running Diversity 1 or 2.	Minor	TDM	The VBA code is hard pasted to update the name for step 109 rather than 110. This updates could be made as a model steps to avoid the need to reference them explicitly in the VBA code. Baringa has noted that these outputs are for diagnostic purposes only.	
35	Relationship between VBA code and spreadsheet ranges is unclear	Minor	ELSI reinforcements	It is not easy to follow/understand the interaction without careful study of the VBA code. Ranges could be coloured/separated to make clear which values are being updated by the VBA code and which are being read.	
36	Endogenous reinforcement code assumes a 2011 base year.	Minor	ELSI reinforcements	VBA code assumes model is being run in 2011. This will need to be parameterised to allow the model to run with a different base year.	
37	Inconsistent length of year between calcs	Very minor	TDM Autogen calculations	In different areas of the model the length of a year varies between 365 and 365.25 days	

A2. The TDM Simulation loop

The TDM goes through the following steps in each run:

- Initial data transfer from the TDM to ELSI – Plant and demand data.
- Initial data transfer from ELSI to the TDM – Reinforcement data.

Then for each modelling year (Y) from the current year to specified end year:

- Data transfer to ELSI – Plant capacities, Short Run Marginal Costs (SRMCs) and Interconnector flows.
- ELSI dispatch algorithm is run for year Y, Y + 1, Y + 3, Y + 5.
- Results transferred from ELSI to the TDM – Prices, gross margins, Interconnector flows and constraint costs.
- ELSI's Transmission Investment model is run.
- Reinforcement decisions reported from ELSI to the TDM.
- Transfer data to T&T model, via the T&T interface, based on year Y + 1 and Y + 5: Generation, MAR, Project costs, Demand information.
- For both Y + 1 and Y + 5
    - Calculate tariffs in the T&T for the year
    - Transfer results to transport model – Tariff for plant, wider tariffs, HH demand, NHH demand and Final MAR
- Run ELSI from transport model
- Run investment/retirement decisions in TDM.

Run next year.

More details on the individual components and how they are calculated can be found in section 2.3.

A3. Summary of data flows between the models

In the tables below we outline how data flows between the models and confirm that this occurs as intended.

Initial transfer from TDM to ELSI

Data item	Description	Source in TDM	Use in ELSI	Mapping correct
Plant availability	The availability of each plant in each season and in each year	Based on a technology specific seasonal availability and allowing for the online/offline dates of the plant and any IED constraints. This also allows for any assumed SCR upgrades that remove the constraints	Used in Calc System Optimiser as the average availability of each plant. Scaled by the Low/High ratio below for low availability calculations	Yes
High low ratio	The ratio between the high availability and low availability for each plant in each season and by year	Technology specific assumption on high and low availability	High availability is used in the highest x% of demand periods in each season.	Yes
Deratings	Derating factor defined for each plant	Derating factor based on technology	Used to calculate a derating factor based on factors other than availability if required.	Yes
Samples	The series for samples for aggregate GB demand (by year) and wind load factor by location. Each sample has a duration and is associated with a given season	Raw data: see data summary	Dispatch is simulated in each sample and aggregated according to the frequency of each sample.	Yes

Initial transfer from ELSI to TDM

Data item	Description	Source in ELSI	Use in TDM	Mapping correct
Initial gone green years for transmission reinforcements	The dates at which each of the reinforcements is currently planned to have been made. 2040 is used as the default date for reinforcements that are not currently planned	Reinforcements that are flagged as assumed committed in the Input network sheet.	Output metric	Yes
Reinforcement costs	The cost of each reinforcement measured in £m	In input network	For output metrics	Yes

Yearly transfer from TDM to ELSI

Data item	Description	Source in TDM	Use in ELSI	Mapping correct
Plant capacities	The capacity of all plant by year including currently online plant and those in the pipeline. It also includes The Master Zone that each plant is located in.	Based on the plant information and investment and retirement decisions made in the TDM.	The Capacity of each unit used in all calculations	Yes
Interconnector capacities	The capacity of all interconnectors by year including currently online plant and those in the pipeline.	Data item.	The interconnector capacities used in the dispatch algorithm	Yes
SRMCs	The SRMC of each unit in each season	Based on plant specific annual calculation of SRMC and then adjusted to allow for seasonal gas prices by season	The definition of the merit order stack used in the simulation	Yes

Yearly transfer from ELSI to TDM

Data item	Description	Source in ELSI	Use in TDM	Mapping correct
Gross margin	The gross margin by plant in year Y, Y + 1, Y + 3 and Y + 5	The gross margin calculated as the profit in the unconstrained run / gross capacity.	Use when calculating plant revenues to inform investment decisions	Yes
Price captured	The price captured by plant in year Y, Y + 1, Y + 3 and Y + 5	(Unconstrained Revenue + Unconstrained uplift income) / generation	Use when calculating plant revenues to inform investment decisions	Yes
Generation	The generation by plant in year Y, Y + 1, Y + 3 and Y + 5	Direct output of ELSI macro	Use when calculating plant revenues and other generation based output metrics	Yes
Interconnector flows	The import and export of each interconnector in year Y	Direct output of ELSI macro	Output metrics	Yes
Pumped storage generation	In year Y	Direct output of ELSI macro	Output metrics	Yes
System wide metrics	The time-weighted and volume-weighted system marginal price along with the mark-up to each applied. Losses in TWh in £m, National grid revenue	Direct output of ELSI macro	Output metrics	Yes
Demand- weighted zonal prices	Demand-weighted price for each zone	Direct output of ELSI macro	Output metrics	Yes
Constraint cost	The aggregate constraint cost in Y, Y + 1, Y + 3 and Y + 5	Direct output of ELSI macro	Output metrics	Yes

Yearly transfer from TDM to T&T

Data item	Description	Source in TDM	Use in Transport and Tariff model	Mapping correct
Actual plant information	Plant name, type, capacity and load factor for actual plant	Based on assumed load factors by plant type.	Plants are mapped to specific nodes in the T&T interface. Capacity and generation by node is passed to the Transport model via Upload_Bus and used in its core power flow model.	Yes
Generic plant information	Equivalent data to the above for generic plant in technology in each relevant zone.	Based on assumed load factors by plant type.	Plants are mapped to specific nodes in the T&T interface. Capacity and generation by node is passed to the Transport model via Upload_Bus and used in its core power flow model.	Yes
MAR	Maximum allowed revenue	MAR calculation sheet	Base MAR is adjusted to Final MAR in the T&T interface, by adding project costs for Offshore & Island projects. Final MAR is used in the Transport model as the "total infrastructure revenue" target, with tariffs adjusted (using Residual) to achieve this target (based on the G/D split).	Yes
Project costs	Project cost (£/kW/year) and the offshore tariff component	Input data	Project costs are used in adjustment of Base MAR to Final MAR in T&T interface model. Offshore tariffs are used in T&T interface to calculate plant-specific tariffs.	Yes
Transmission project	HVDC reinforcement commissioned if online in Y + x	From ELSI	If commissioned, the HVDC line is added to network in transport model	Yes
G/D split	The proportion of the total transmission cost met by Generation in year Y + x	Input assumptions	T&T tariff model calculates proportion of total revenue target from Generation & demand based on this assumption (73%).	Yes
Annual demand	Total GB annual demand in TWh	Data item	Not used	
Peak demand	Maximum GB peak demand in GW	Data item	Not used	

Yearly transfer from T&T to TDM

Data item	Description	Source in Transport and Tariff model	Use in TDM	Mapping correct
Final tariff for actual plant	Final tariff for each existing plant	Calculated in T&T interface, on Input_Generation sheet, based on wider & local tariffs from T&T model	Revenue calculations and output metrics	Yes
Final tariff for generic plant	Final tariff for each existing plant	Calculated in T&T interface, on Input_Generation sheet, based on wider & local tariffs from T&T model	Revenue calculations and output metrics	Yes
Wider tariffs	Zonal tariffs (£/kW) for the 20 zones	Output from Tariff model calculation to Output_Tariffs sheet in T&T interface	Revenue calculations and output metrics	Yes
Local Tariffs	Local tariffs for the c.72 substations, £/kW	Output from Tariff model calculation to Output_Tariffs sheet in T&T interface	Revenue calculations and output metrics	Yes
HH Demand tariffs	HH Zonal tariffs for the 14 zones, £/kW	Output from Tariff model calculation to Output_Tariffs sheet in T&T interface	Revenue calculations and output metrics	Yes
NHH Demand tariffs	HH Zonal tariffs for the 14 zones, p/kWh	Output from Tariff model calculation to Output_Tariffs sheet in T&T interface	Revenue calculations and output metrics	Yes
Final MAR	Final MAR	Base MAR plus other additions based on project costs, on Input_Financial sheet	Output metric	Yes

A4. Overview of the internal calculations in the TDM

MAR Calcs

The calculation takes Opex and Capex information from the RIIO business plans for each operator in order to project the total Regulated Asset Value (RAV) and Maximum Allowed Revenue (MAR) across the three operators each year.

The total Capex for investment in reinforcements is subtracted from the total RIIO Capex for any of the reinforcement being modelled endogenously. For these reinforcements the build decision and associated cost is calculated within the ELSI model.

The calculation first projects RAV (Regulated Asset Value) over time including the following elements:

- Pre RIIO Depreciation: Assumes 20 year depreciation lifetime, on the 2013/14 RAV less disposals to date
- Pre RIIO Disposals: 0.5% of the 2013/14 RAV pre 2020 and 5% post 2020
- Reinforcement Capex for endogenously modelled projects. This is provided by the ELSI model and the cost can to be spread over 1 to 3 years. Currently a value of 2 is used.
- RIIO Capex: The total RIIO Capex excluding modelled transmission Capex as a per annum amount + reinforcement capex for endogenously modelled projects.
- RIIO Depreciation: Cumulative RIIO CAPEX depreciated over 45 years.

The end of year RAV value is equal to the beginning of year RAV value plus reinforcement investment less depreciation and disposals.

The base MAR (Maximum allowed revenue) is then calculated in each year as follows:

Base MAR = 4.55% of average RAV over the year = (start RAV + end RAV)/2
+ Depreciation
+ RIIO Opex
+ Other items (tax, pension, excluded revenue etc. = £550m per annum)

Base MAR is adjusted pre 2013 to be the T&T modelled MAR less the OFTO cost for offshore wind.

The MAR in respect of endogenous reinforcement is also calculated based on the same method.

Low carbon build

Calculation element	Description / calculation
Cumulative build	Input from **"**Capacities" sheet
Plant additions	The annual changes in the cumulative build
Built under RO	Whether plant built in the year will receive a RO. This is based on the CfD start date
Built under CfDs	Whether plant built in the year will receive a CfD. This is based on the CfD start date
Active subsidy for plant that begins construction now	Determines whether a ROC or CfD applies to plant that is constructed in the current model year. i.e. based on Current model year + construction period >= CfD start year:
	When a ROC applies: ROC price * ROC banding + LEC price if eligible
	When a CfD applies: Strike price - reference price (assumes LECs don't apply)
	In this calculation the reference price is assumed to be the LRMC of a new CCGT
Output based subsidy capacity weighed	Weighted average support in payment across the current capacity installed.
Proportion of plant built under CfDs	The proportion of new build plant build under CfDs
Active ROC Band	The ROC band in-force for plant that begin construction in the current model year.
Capacity weighted ROC band	The average ROC band for plant that are in operation at the current modelling year
Active CfD level	The CfD support in-force for plant that begin construction in the current modelling year.
Capacity weighted CfD	The average CfD support level for plant that are in operation at the current modelling year.

Annual costs

Calculation element	Description / calculation
Capital costs £/KW	The capital cost for each plant type in each year. This is based on data from the capacity sheet with an adjustment for offshore wind plant based on water depth and foundation costs**.**
Annuitised Capital costs (£/kw/yr)	Capital costs converted into levelised costs. Uses VBA function based on gearing ratio and cost of debt/equity.
TNUoS charges (£/kw/yr)	Wider charges from the Transport model interface, Hard pasted for 2011
Gas exit charges	Input assumption. The 2014 value used for all years after year 2014
Total fixed costs (£/kw/yr)	Gas exit + TNUoS + Fixed operation and maintenance costs based on plant type
Total annual costs (£/kw/yr)	Total fixed costs + annuitised capital costs
Annual constraint cost (£m)	From ELSI output
Constrain cost in BSUoS (£/MWh)	Constraint cost / Annual demand * 50% (for generation/demand split)
Total VOM (£/MWh)	Variable TNuOS + Base BSUoS + Constraint cost + VOM from Common assumptions + Balancing cost
	Balancing cost is an additional cost for intermittent generators
LRMC (£/MWh)	Total fixed costs / hours per year that the plant is expected to run + SRMC from E_Stack spec. Base availability is the assumed load factor here.
Average LRMC for new build plants (£/MWh)	Average of the LRMC above by plant type
LRMC excluding fixed TNUoS (£/MWh)	As with LRMC above with TNuOS / Expected operational hours subtracted

E_StackSpec

Calculation element	Description / calculation
IED Constraints	Calculates the maximum load factor for each plant from LCPD through to IED-LLO or IED-TNP ▪ LCPD plant assumed to be running uniformly from 2008 to 2016 in using their 20000 hours ▪ Plant expected to fit SCR are unrestricted ▪ LLO assumes 17500 hours used uniformly over the 8 years ▪ If oil unconstrained
Co-firing fuel and fuel ratio	Assumption on the co-firing proportion of plants from scenario assumptions
Closure year	▪ Based on assumed closure dates ▪ If LCPD Opt-out 2015 ▪ If IED LLO 2020
Base annual availability	Zero if plant is not online. If fit SCR then unconstrained otherwise reads relevant load factor for above. Based on IED assumption above where applicable
SRMC primary and secondary fuel	(Fuel cost + net carbon cost + fuel transport cost)) / Efficiency + VOM charges from Annual costs sheet
Subsidy primary and secondary fuel:	***Exiting plant:*** Based on ROCs + LECs ***New plant:*** Based on ROCs + LECs/CfD weighted by capacity prior to the models current year and current support level otherwise
SRMC pre seasonal adjustment for gas	Weighted average by fuel ration of the above net generation cost based on the above plus allowance for SCR VOM from plant assumptions.
Gas price seasonality adjustment	Seasonal adjustment to SRMC based on gas price and seasonality assumption in Common assumptions

E_Supply curves

Calculation element	Description / calculation
High and Low base availabilities by season	This is the seasonal availability profile by plant type for both the high and low availability stacks. This is done subject to: ▪ A defined ratio of high availability to low availability specified by plant type ▪ The seasonal availability profile as specified by plant type ▪ Achieving the average annual availability. The parameters here have been calibrated against PLEXOS.
High and low availability assumptions for each IED plant	***For plant that fit SCR:*** ***For all seasons*** Load factor * high availability assumption by plant type subject to a maximum load factor in winter and shoulder-winter. ***For plant that don't fit SCR:*** ***Winter*** Limited load factor is used as much in winter as possible subject to the cap multiplied by the High availability in the winter season. ***Other seasons*** The remaining hours are split across the other 3 seasons proportionally to the seasonal availabilities by plant type.
High and low availability for each season by plant	***Non IED plant*** Plant type specific availability scalar * base availability ***IED plant*** Read in for the relevant periods based on the above
SRMC stack by season	SRMC from E_StackSpec adjusted for gas price seasonality.

E_PowerPriceCalcs

In the CMP213 modelling ELSI is used to calculate the dispatch decisions so we have not reviewed the formulae relating to dispatch decisions.

E_PlantWiseGenResults

Calculation element	Description / calculation
Annual generation by plant	From ELSI, Embedded generation based on capacity and load factor assumption
Fuel consumption by plant (GWh)	Annual generation / efficiency
Carbon emissions by plant	Fuel * Carbon intensity * Proportion fuel 1 * (1 - Abatement), assumes no emissions from fuel 2.
Price captured by plant (£/MWh)	From ELSI
Capacity installed by plant	From Capacities sheet
Load factor by plant	Generation / Capacity
Gross Margin by plant	***Non CfD*** (Price captured - SRMC) * Generation ***CfD*** as with non CFD plus and adjustment so that the revenue per MWh is equal to the strike price.
Annual gross margin after fixed costs by plant	Revenue received / capacity less fixed costs from “Annual costs”
Capacity mechanism by plant	The formulae here are not available for review see section 2.3.8
Annual gross margin including capacity mechanism revenue by plant	If plant clears the auction the payment received
Total profit by plant	Gross margin multiplied by capacity

Capacity mechanism

We ran sensitivities on the two main drivers of the capacity mechanism, the required margin and the derating factors applied.

- **The required capacity margin** – to ensure that the capacity commissioned changed by the anticipated order of magnitude.

  We reduced the required mechanism margin from 10% to 5%. The effect of this was of the right order of magnitude.

  We increased the required mechanism margin from 10% to 15%. The result of this was not as significant as we would have expected. Notably the capacity mechanism clearing price did not materially increase. Care should be taken when running the capacity mechanism to ensure that there is sufficient new build plant available to clear the auction, otherwise the clearing price will not rise to the correct level and the capacity margin will not be met.

- The **derating factors applied** – to ensure that the capacity commissioned decreases by the anticipated order of magnitude. We adjusted the derating factors of CCGT's and the effect was as we would expect.

Investment and retirement decisions

We have run the following sensitivities on all of the variables above and the model reacted as we would expect.

Variable	Sheet	Sensitivity	Expected	Result
Retirement limit	CommonAssumptions	Set Coal retirement limit to 3,000MW in 2017	2017 retirements reduced to below 3,000 MW	Coal retirements reduced from 3,604MW to 2,035MW in 2017.
Max capacity ind plant	Capacities	Force Barking to close in 2028 by setting its max capacity to 0	Barking closes in 2028	As expected. 950MW extra retirements in 2028 (vs. basecase), corresponds with size of Barking.
Capital costs	CommonAssumptions	Onshore wind capital costs set to 9999 for 2014-16	Onshore build equal to min allowed in 2014-16. Change is reflected in the capital cost results.	As expected, only minimum onshore build in 2014-16 (significantly lower than basecase). Capex results reflect high costs.
Min capacity	Capacities	Set min capacity for Onshore Wind - Zone I to same as max in 2014	Increase in Onshore Wind build to new minimum level, despite	As expected. Onshore wind Zone I builds 2859MW.

		(2859MW)	high capital costs (test above).
Cap margin	CommonAssumptions	Increase from 10% to 15%	Capacity margin output is 5% higher than b/c. Cap market clearing prices are higher

A5. Overview of the reinforcement decisions calculation within ELSI

The functionality we have reviewed is code in the "TransInvestment" VBA module and the additional spreadsheet calculations added to "Input network" tab that are used by the VBA code.

The modelling methodology proceeds as follows:

If the model is currently in year Y then calculation is based on calculating the potential reduction in constraint costs in years Y + 3 and Y+ 5.

The steps of the calculation are as follows:

- Base case results are recorded as the counter-factual for making the decision. For years Y + 3 and Y + 5.
  - Aggregate constraint costs
  - The reinforcements to test.
  - The potential constraint savings from the ELSI calculation.
  - The annual results from ELSI. This includes prices, zonal prices interconnector flows etc.
- While there are reinforcements to consider:

  1.) Choosing reinforcement to test

  - The reinforcement to be tested is calculated by excel formulae based on the results above. This is done as follows:
    - The potential savings that could be achieved by boundary are taken for the ELSI baseline results.
    - For each boundary with a constraint cost the projects that have a reinforcement that could relieve it are selected.
    - For the boundary with the greatest potential for constraint reduction the reinforcement available with the lowest cost is chosen.

  2.) Calculating the reduction in constraint cost

For year Y + 3 and Y +5

- Baseline is recorded (as this may have changed now that a new reinforcement could have been built)
- Sets the reinforcement being considered to be built by overriding and making it active.
- ELSI is rerun and the total constraint cost recorded.
- Results of ELSI run are stored in the evaluation sheet.
- Reinforcement returned to inactive state.

3.) Making a decision: The decision logic is as follows:

- If reinforcement has been tested in both Y + 3 and Y + 5 at its average reduction in constraint cost is greater than the levelised cost build for year 3.
- Otherwise if reduction in constraint cost in year Y+ 5 is greater than the levelised cost build for Y + 5.
- Otherwise don't reinforce.

4.) Post decision making:

- Base line results updated to act as the counterfactual to further decisions.
- Decision and online year reported.
- If a reinforcement has been made then this is updated in the gone green scenario and the overridden year is recorded.

Check next reinforcement

This reinforcement process above is then repeated for reinforcements that are only available from year 5 onwards.

A6. Summary of Nodal Marginal Cost tests run on the T&T model

All the nodal marginal costs tested were verified as internally consistent (indicated by green highlighting).

Status quo

		T&T Marginal Cost Results (km)			LCP calculated Marginal Costs (km)		
Node tested	Adjustment	Demand	Wider	Local	Demand	Wider	Local
1: ABHA4B	+1MW	-387.44	-387.44	0.00	-387.44	-387.44	0.00
10: BAGB20	+1MW	-681.34	-705.73	24.39	-681.34	-705.73	24.39
76: DINO40	+1MW	-1206.69	-1297.19	90.50	-1206.69	-1297.19	90.50
272: BLLA10	+1MW	-3056.26	-3089.12	81.76	-3056.26	-3089.12	81.76
500: GLEN1Q	+1MW	-2608.72	-2638.29	95.66	-2608.72	-2638.29	95.66

Original

			T&T Marginal Cost Results (km)			LCP calculated Marginal Costs (km)		
Node tested	Adjustment		Demand	Wider	Local	Demand	Wider	Local
1: ABHA4B	+0.01MW	Peak: YR:	-438.63 -70.25	-438.63 -70.25	0.00	-438.63 -70.25	-438.63 -70.25	0.00
10: BAGB20	+0.01MW	Peak: YR:	449.78 -369.60	425.29 -369.60	24.49	449.78 -369.60	425.29 -369.60	24.49
175: MAWO40	+0.01MW	Peak: YR:	531.92 -122.90	517.54 -122.90	-8.72	531.92 -122.90	517.54 -122.90	-8.72
495: FOYE20	+0.01MW	Peak: YR:	-1010.31 1775.16	-1010.31 1746.41	28.75	-1010.31 1775.16	-1010.31 1746.41	28.75
232: SUND40 (ref node)	+0.01MW, and manual change to ref bus order	Peak: YR:	-694.27 -152.34	-694.27 -152.34	0.00	-694.27 -152.34	-694.27 -152.34	0.00

Diversity 1

Node tested	Adjustment		T&T Marginal Cost Results (km) Demand	Wider	Local	LCP calculated Marginal Costs (km) Demand	Wider	Local
10: BAGB20	+0.01MW	Peak: YR:	310.03 -190.58	281.05 -190.58	28.98	310.03 -190.58	281.05 -190.58	28.98
52: CARR40	+0.01MW	Peak: YR:	86.27 -60.83	86.27 -54.60	-6.24	86.27 -60.83	86.27 -54.60	-6.24
53: DAIN40 (ref node)	+0.01MW	Peak: YR:	84.96 -66.51	84.96 -66.51	0.00	84.96 -66.51	84.96 -66.51	0.00
122: HATL20	+0.01MW	Peak: YR:	225.61 276.02	212.46 267.78	-21.40	225.61 276.02	212.46 267.78	-21.40

Diversity 2

Node tested	Adjustment		T&T Marginal Cost Results (km) Demand	Wider	Local	LCP calculated Marginal Costs (km) Demand	Wider	Local
1: ABHA4B	+0.01MW	Peak: YR:	69.40 -59.39	69.40 -59.39	0.00	69.40 -59.39	69.40 -59.39	0.00
52: CARR40	+0.01MW	Peak: YR:	36.85 -30.26	36.28 -24.61	-5.08	36.85 -30.26	36.28 -24.61	-5.08
122: HATL20	+0.01MW	Peak: YR:	126.06 193.93	130.80 203.43	2.36	126.06 193.93	130.80 203.43	2.36

Diversity 3

Node tested	Adjustment		T&T Marginal Cost Results (km) Demand	Wider	Local	LCP calculated Marginal Costs (km) Demand	Wider	Local
1: ABHA4B	+0.01MW	YR:	-423.74	-423.74	0.00	-423.74	-423.74	0.00
10: BAGB20	+0.01MW	YR:	78.62	49.65	28.98	78.62	49.65	28.98
691: HADH10	+0.01MW	YR:	1173.35	1120.23	190.00	1173.35	1120.23	190.00
850: NEWF10	-0.001MW adding gen causes step change in MCs	YR:	530.24	634.56	-295.22	530.24	634.56	-295.22

A7. Numerical example outlining the error in Diversity 3 ZSF calculation

During our review, an error was found in the Diversity option 3 model's Zonal Sharing Factor (ZSF) calculation. Here we provide a numerical example of this error, based on 2012/13 data provided for testing.

In diversity 3, Zone 15 (South Wales) has a marginal cost of +23.9km, before we consider the effect of sharing. This is comprised of two parts: an extra +236.0km needed in Zone 15(South Wales) itself, and a saving of -212.1km in its neighbouring Zone 18 (South Coast).

Applying sharing:

Z15 is 2.6% low-carbon therefore, under the definition of the "diversity 3" option, this portion can be shared. Z18 is 15.8% low-carbon. The "non-shared" portion should therefore be 236*97.4%+(-212.1)*84.2% = 51.3km. This becomes the new marginal cost, and is 215% of the original 23.9km.

This calculation is consistent with the wording in the draft legal text (Page 239, 14.15.45 and 14.15.46). http://www.nationalgrid.com/NR/rdonlyres/631B8FB3-84D1-4D32-9F35-79E66AE06832/60060/WRVol4_FinalCAConsultation_V10.pdf

What the T&T model did:

Calculates a ZSF (Zonal Sharing Factor) for each node, which represents the non-shared %. For Z15, the ZSF is calculated as 1 – abs(2.6%*236 + 15.8%*(-211.1)) / 23.9 = -15%. The model then goes on to apply this -15% to the marginal cost (along with other adjustments).

The discrepancy is due to the formula taking the absolute value of the shared component. Without this it would produce 215%, as calculated above.

The calculations in Diversity 1 and 2 don't calculate a ZSF in the same way, so don't have the same issue.

A8. Data inputs

Data item	Location	Description	Comment
Plant data			
Base availability	Common assumptions	The standard operating availability by plant	Assumption appears reasonable
Derating	Common assumptions	The derating factor applied for the capacity mechanism and for some capacity margin calculations	Consistent with assumptions used for DECC EMR consultation
Shape of availability (for 4 seasons)	Common assumptions	The seasonal variation in availability	Calibrated via testing in ELSI combined with review against PLEXOS
Base VOM (£/MWh)	Common assumptions	Variable operation and maintenance costs in £/MWh	Sourced from DECC-commissioned reports. Source differs by technology: E&Y (marine), ARUP (others renewable), and PB Power (non-renewable) reports. Assumptions agreed against PB power report, other assumptions appear reasonable
Balancing cost (£/MWh)	Common assumptions	Balancing costs, only non-zero for intermittent technologies	Assumption appears reasonable
Base FOM (£/kw)	Common assumptions	Fixed operation and maintenance costs in £/kW pa	Sourced from DECC-commissioned reports. Source differs by technology: E&Y (marine), ARUP (others renewable), and PB Power (non-renewable) reports. Assumptions agreed against PB power report, other assumptions appear reasonable
Efficiency	Common assumptions	The base efficiency assumption for the plant type	Sourced from DECC-commissioned reports. Source differs by technology: E&Y (marine), ARUP (others renewable), and PB Power (non-renewable) reports. Assumptions agreed against PB power report, other assumptions appear reasonable
Emissions intensity (t/MWh)	Common assumptions	Tonnes of CO_2 per MWh of generation	Standard Redpoint modelling assumptions, appears reasonable
Abatement (%) for	Common	90% Abatement for CCS technology	Assumptions of 90% for CCS is reasonable and not material to the modelling

Data item	Location	Description	Comment
CCS	assumptions		results
Individual unit assumptions	Common assumptions	Generation fleet information: online, offline dates, capacities, efficiencies etc.	Based on ELSI plant data with plant specific updates to known announcements

Build decision assumptions

Build planning/decision	Common assumptions	The build time for new projects	Sourced from DECC-commissioned reports. Source differs by technology: E&Y (marine), ARUP (others renewable), and PB Power (non-renewable) reports. Assumptions agreed against PB power report, other assumptions appear reasonable
Economic life	Common assumptions	The economic life time for the build decision	Sourced from DECC-commissioned reports. Source differs by technology: E&Y (marine), ARUP (others renewable), and PB Power (non-renewable) reports. Assumptions agreed against PB power report, other assumptions appear reasonable
Operational life	Common assumptions	The expected operational life time of the plant	Sourced from DECC-commissioned reports. Source differs by technology: E&Y (marine), ARUP (others renewable), and PB Power (non-renewable) reports. Assumptions agreed against PB power report, other assumptions appear reasonable
Generic generation type load factor	Common assumptions	Used for the generic plant for the transport model interface	From National Grid, assumptions appear reasonable
Max retirement (MW)	Common assumptions	Annual retirement limit in MW	Based partially on NG accelerated growth scenarios. Assumptions appear reasonable
Max annual commitment (MW)	Common assumptions	Annual build limit in MW	Modelling assumption informed by NG accelerated growth modelling scenario, assumptions appear reasonable
Capital costs	Common assumptions	Capital costs by plant type and by year (£/kw)	Based on latest DECC views, assumptions appear reasonable.
Hurdle rates	Common	Hurdle rate required by technology	Derived from the fundamentals: Cost of Debt, Equity premium, Risk free rate,

Data item	Location	Description	Comment
	assumptions		Inflation, Tax rate and then Equity Beta and debt gearing by plant type. Assumptions appear reasonable
Foundation costs	Common assumptions	Capital cost and assumed depth. It is assumed that the default capital costs for offshore wind include an allowance for foundation costs at an assumed depth. This input is used to adjust the capital costs of other wind projects based on their capital costs.	Appears reasonable
Zonal assumptions			
Zones	Common assumptions	Master zones and their mapping to TNuOS, System and Gas exit zones.	Assumptions Informed by Redpoint and National grid.
Gas exit charges	Common assumptions	Gas exit charges by zone and amount in £ / kw/ yr	Sourced from the Charging Statement
LCPD/IED assumptions			
Constraint type / unit choice	Scenario assumptions	LCPD, IED-LLO, IED TNP or Fit SCR for each relevant plant	
Limited load factor	Scenario assumptions	Limited load factor for the relevant periods based on the constraint type	Model calibration parameter. Derived from calibration against PLEXOS
Maximum winter operating factor	E_SupplyCurves	A maximum that a 42.857%	Model calibration parameter. Derived from calibration against PLEXOS
Fuel and carbon			
Gas and coal prices	Scenario assumptions		Central scenario from DECC's 2012 Energy and Emissions Projections. Checked raw data and conversion to MWh calculation

Data item	Location	Description	Comment
Carbon price	Scenario assumptions	EUETS price underpinned by the CPS	DECC's carbon price: "For modelling purposes". Checked against raw data
Gas oil and Fuel oil	Scenario assumptions		Assumptions appears reasonable
Biomass and nuclear	Scenario assumptions		Assumptions appears reasonable
Carbon intensity (t/MWH)	Common assumptions	By fuel type	Assumptions appears reasonable
Shadow carbon intensity (abatement specific)	Common assumptions	By fuel type	Assumptions appears reasonable
Transportation cost (£/GJ)	Common assumptions	By fuel type	Assumptions appears reasonable
Gas price seasonality	Common assumptions	By fuel type	Assumptions appears reasonable
Demand			
Demand load curve shape	E_PowerPriceCalcs	The 100 percentiles of the demand distributions in each season	Based on historical data. Assumptions appears reasonable
Peak demand growth	E_PowerPriceCalcs	Each percentile of the demand distributions growth rate over time	Checked against National Grid Gone green scenario
Embedded generation			
Load factors	Common assumptions	Load factors and derating for each type of embedded generation source	From NG Gone Green scenario (supporting spreadsheet which may not have been published)

Data item	Location	Description	Comment
Capacity	Capacities	Capacity of each type of embedded generation type by year	From NG Gone Green scenario (supporting spreadsheet which may not have been published)
Other			
Price mark-up	Common assumptions		Assume this is a derived based on historical data/calibrated against PLEXOS
VoLL	Common assumptions		£1000 seems low, assume this is adjusted to avoid high price spikes
Wind			
Wind load factors	WindLoadFactor	The annual average load factor achieved in different location	Assumptions appear reasonable
High level investment modelling parameters			
Build look forward	Common assumptions	Look forward period used for new build decisions	Agreed with the TransmiT working Group as part of methodology discussions
Retirement look forward	Common assumptions	Look forward period used for retirement decisions	Agreed with the TransmiT working Group as part of methodology discussions
% planning in forward view	Common assumptions		Modelling assumption
% retirements in forward view	Common assumptions		Modelling assumption
Require derated capacity margin	Common assumptions	Assumption to approximate the security standard for the Capacity Mechanism	Consistent with assumptions used for DECC EMR consultation

Data item	Location	Description	Comment
Capacity mechanism start date	Common assumptions	The first delivery year the for the capacity auction	Consistent with 2018/2019 date stated by Government in latest documents
Stack split	Common assumptions	The percentile of the demand distribution where the switch occurs between the high and low availability stack in the modelling	Calibrated via testing in ELSI combined with review against PLEXOS
Ratio High/Low stack	Common assumptions	The ratio of high availability to low availability by plant type	Calibrated via testing in ELSI combined with review against PLEXOS