Notice of Proposed Income Adjusting Event – Transmission Losses 2011-13

Submitted on: 28 June 2013

About this document

This document sets out the additional costs incurred by the System Operator as a result of transmission losses within the 2011-13 Balancing Services Incentive Scheme and the reasons that National Grid considers this to constitute an Income Adjusting Event in accordance with Special Condition AA5A Part 2(i), paragraph 11 of National Grid Electricity Transmission plc's Transmission Licence.

Executive Summary

1 The Transmission Losses (losses) component of the 2011-13 Balancing Services Incentive Scheme (BSIS) has increased the incentivised balancing costs (IBC) of the scheme by £107.9m following an outturn volume of losses at 12.11TWh compared to a scheme target of 8.9TWh.

2 Transmission Losses on the National Electricity Transmission System (NETS) are primarily due to the geographical dispersion of market supplied generation. It would not be economic or efficient for National Grid to re-dispatch generation solely to reduce losses; to do so may in fact increase carbon emissions due to the location of renewable generation in relation to thermal generation and demand centres. Our analysis suggests that if we were to take actions to reduce losses across a one year period it would cost in the region of £4.3bn. This would be contrary to National Grid's obligations as SO and would not be in the best interest of consumers.

3 The losses target for the 2011-13 BSIS scheme of 8.9TWh was agreed on the assumption that increases in southern generation were expected to offset the growth of wind connecting in Scotland. However, due to events outside of the control of National Grid, including changes in spark spreads and delays to new commissioning generation in the south, the level of outturn has been significantly higher than anticipated by either National Grid or Ofgem.

4 This is the first scheme in which transmission losses have been sufficiently high that they have had a direct financial impact on the incentive scheme outcome. In turn, this has reduced the strength of incentive on other cost areas over which National Grid has a greater degree of control. This has been recognised in Ofgem's Final Proposals[1] for a 2013-15 BSIS scheme where the financial incentive to reduce losses has been removed.

5 We therefore propose that the outturn of Transmission Losses for 2011-13 constitutes an income adjusting event (IAE) which has resulted in significant costs being incurred by the SO. The subsequent level of income adjustment if losses were to be determined by Ofgem as an IAE would be a £21m income to National Grid following application of the 25% incentive sharing factor.

[1] Ofgem's Final Proposals document can be found at: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=344&refer=Markets/WhlMkts/EffSystemOps/SystOpIncent

Contents

1. Background

6 Transmission Losses (losses) occur due to the physical properties of electricity transmission systems, principally resistance.

7 Two sources of losses occur in transmission systems. These are:

(a) Fixed losses - These occur within the iron cores of transformers, cables and overhead lines whenever the circuit is energised. The magnitude of these losses is not dependent on the magnitude of the current being carried by the conductor but rather the magnetic field created by the applied voltage and the induced currents this creates within the iron core. As the voltage is more or less constant, these losses are also considered non-varying; and

(b) Variable Losses - These are the “classic” losses which vary with the current carried by the conductor. These losses occur in cables, overhead lines and transformers and are dependent on the degree of resistive heating experienced. As variable losses are associated with the flow of power across the network, these are, in principle, considered to be more within the control of the SO through its operational decisions. However, in practice these flows are dictated primarily by the pattern of generation, which is determined by the commercial decisions of individual generators responding to market conditions and, in particular, by the decisions of generators as to where they locate new generating stations and close existing ones.

8 Losses in transmission systems are a function of the current carried by the conductors. The loss experienced in a conductor carrying alternating current is given by the equation I^2R, where I is the current and R is the resistance of that conductor. This resistance causes energy to be absorbed by the conductor which results in the conductor heating up in the same way as an electric bar heater or the element in a kettle. This energy is lost to the surroundings.

9 The resistance of an individual conductor is in turn a function of the materials used in its construction, how these are combined, and the length of the conductor.

10 Multiple transmission system components can be considered as a single route with its own characteristics. In this way the route that energy fed in to the north of Scotland takes to reach the demand centres in the south of England can be thought of as a very long conductor. As a longer length increases the overall resistance, and hence losses, the location of generation infeed relative to demand will affect the level of losses experienced.

2. Losses Incentive Target

11 A financial incentive on losses has been included in the Balancing Services Incentive Scheme (BSIS) throughout their history. Since 2008/9 this has been on the basis of a “Transmission Losses Incentive Cost” arrangement where a target level of losses has been set, a deadband applied around this and a price for any variance outside of this agreed on a £/MWh basis. Prior to this losses were included as an absolute value multiplied by a set price per MWh. Under both arrangements this price was based on wholesale energy and was set pre-scheme until the 2011-13 scheme where it was set on a post-scheme

basis but still based on wholesale prices. The resulting 'cost' of losses is then added to the external balancing costs to form the total incentivised balancing cost around which the BSIS scheme (sharing factor and cap/collar) operates.

12 The losses volume target for the 2011-13 scheme was set at 8.9TWh ±0.6TWh by Ofgem[2] for the two year scheme period, which equates to annual targets of 4.45TWh. This was on the basis that increases in southern generation were expected to offset the growth of wind connecting in Scotland. The outturn volume of losses for 2011-13 was 12.11TWh at a reference price of £47.054/MWh thereby resulting in a cost impact of £107.9m to the incentive scheme (See 'Financial Impacts' section below for further detail).

13 The 2011-13 losses scheme target was also set, in part, on the basis of the outturn from 2010/11 which was lower than preceding years. This is shown in the chart in Figure 1 below which sets out the yearly volume targets for losses within each incentive scheme since 2005/06 against the outturn volume for each year.

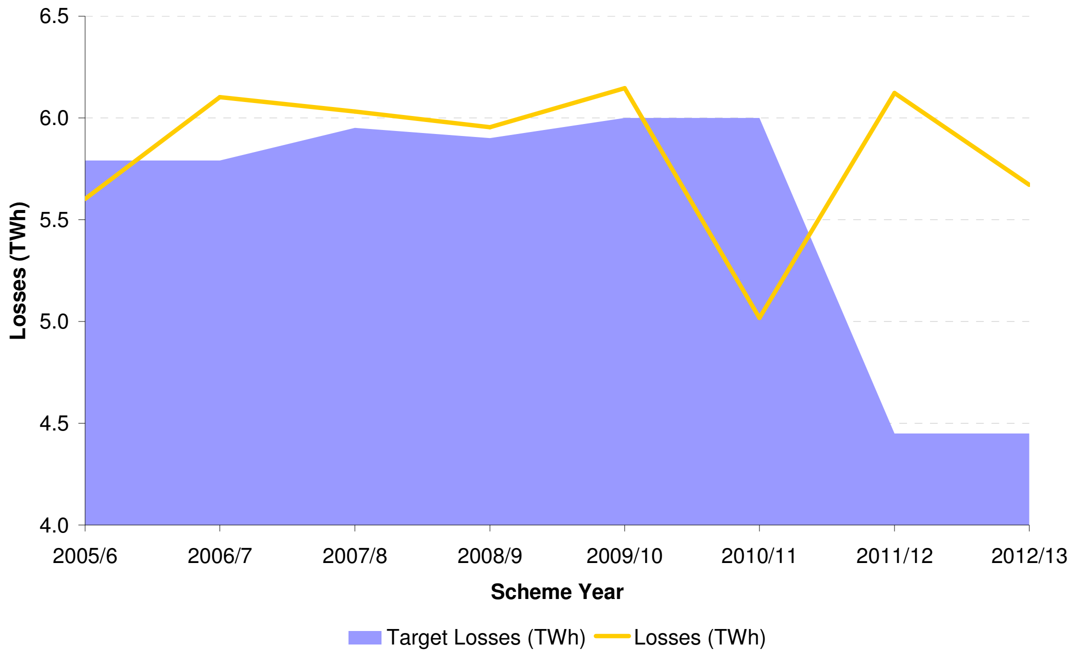

Figure 1: Transmission Losses Volume and Target since 2005/6

14 As can be seen from the graph losses have typically out turned at around 6TWh in each year with 2010/11 being an outlier at 5TWh. This information led National Grid to originally propose a losses target for the 2011-13 scheme of 5.5TWh per annum, or 11TWh for the scheme duration, to Ofgem. However following further discussion the target was reduced to 8.9TWh.

15 Losses on the transmission system are calculated from Elexon data received via the SAA-IO14 dataflows. Specifically the calculation is the difference between the infeed and offtake from the system i.e.

$$\text{Losses} = \sum_{MWh>0} \text{Metered Output} + \sum_{\text{MWh}<0} \text{Metetred Output}$$

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2 See Chapter 5 of Ofgem's Final Proposals :http://www.ofgem.gov.uk/Markets/WhlMkts/EffSystemOps/SystOpIncent/Documents1/National%20Grid%20Electricity%20Transmission%20SO%20incentives%20from%201%20April%202011%20FINAL.pdf

16 As 2010/11 was substantially below the expected target, and the historic level of transmission losses, Elexon were asked to verify that there were no metering errors within this data. None were found.

17 The reduction in losses in 2010/11 was therefore attributed to the high load factors achieved by newly synchronised generation in the south of England. As this generation is closer to the demand than the older plant it would be expected to displace in the market this would result in lower losses and hence drive this reduction. This is demonstrated in the generation heatmap below which compares generation in 2010/11 compared with generation in 2009/10.

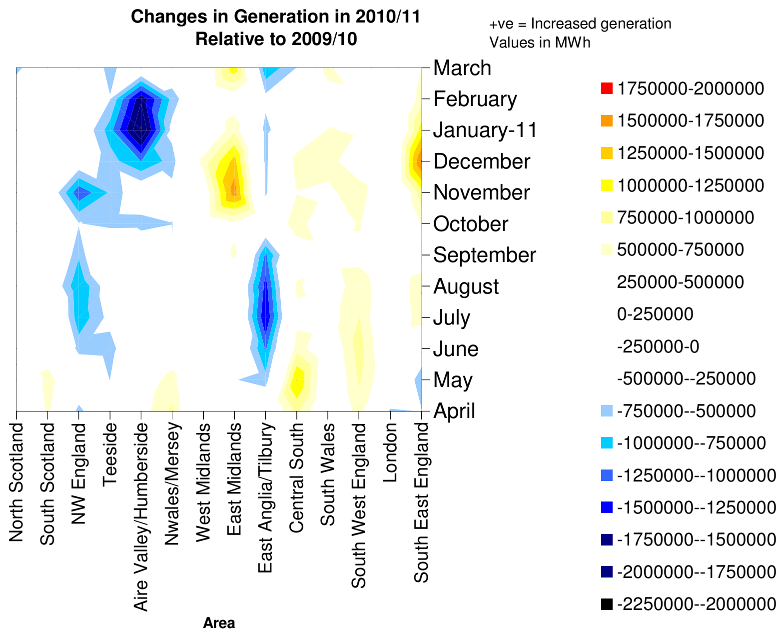

Figure 2: Heatmap of 2010/11 Generation Relative to Previous Year

18 For the 2011-13 incentive scheme it was therefore envisaged that newly commissioned CCGTs in the South would continue to achieve high load factors over the incentivised period, potentially offsetting some of the increased power flows that were expected across the reinforced Cheviot boundary (due to increased wind generation in Scotland). Following discussions with Ofgem, a target for losses was agreed based on the impact of new southern generation being greater than originally envisaged and the expected connection of renewable generation in Scotland being lower than originally expected.

19 In practice, changes in spark spreads, and delays to the commissioning of new plant, have meant that gas-fired generation in the South has not operated as anticipated, and has typically been replaced by coal-fired generation in the North. This, amongst other factors, has led to losses being higher than expected at April 2011 when the target was set as a result of events outside of our control. This impact is explained further in the section below.

20 This change in expected versus actual generation patterns is shown in the two heatmaps below which show a general increase in northern generation and a decrease in southern generation, particularly in the South West.

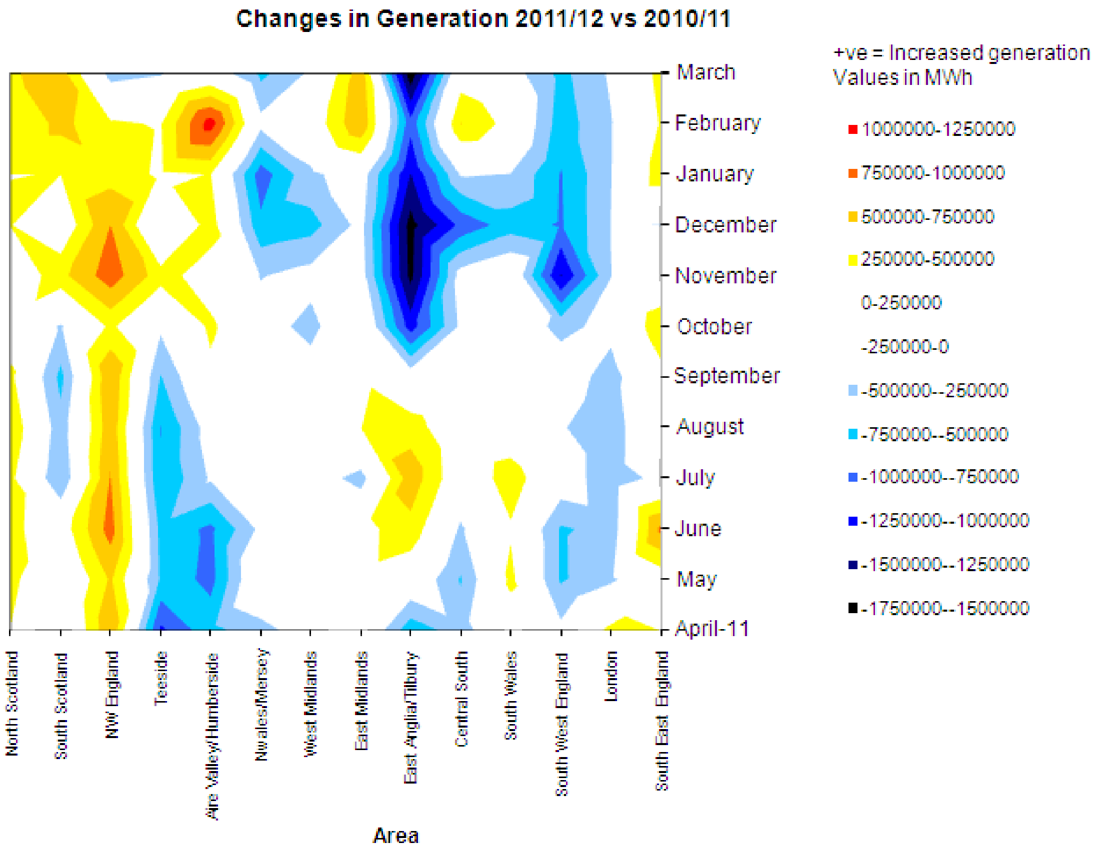

Figure 3: Heatmap of 2011/12 Generation Relative to Previous Year

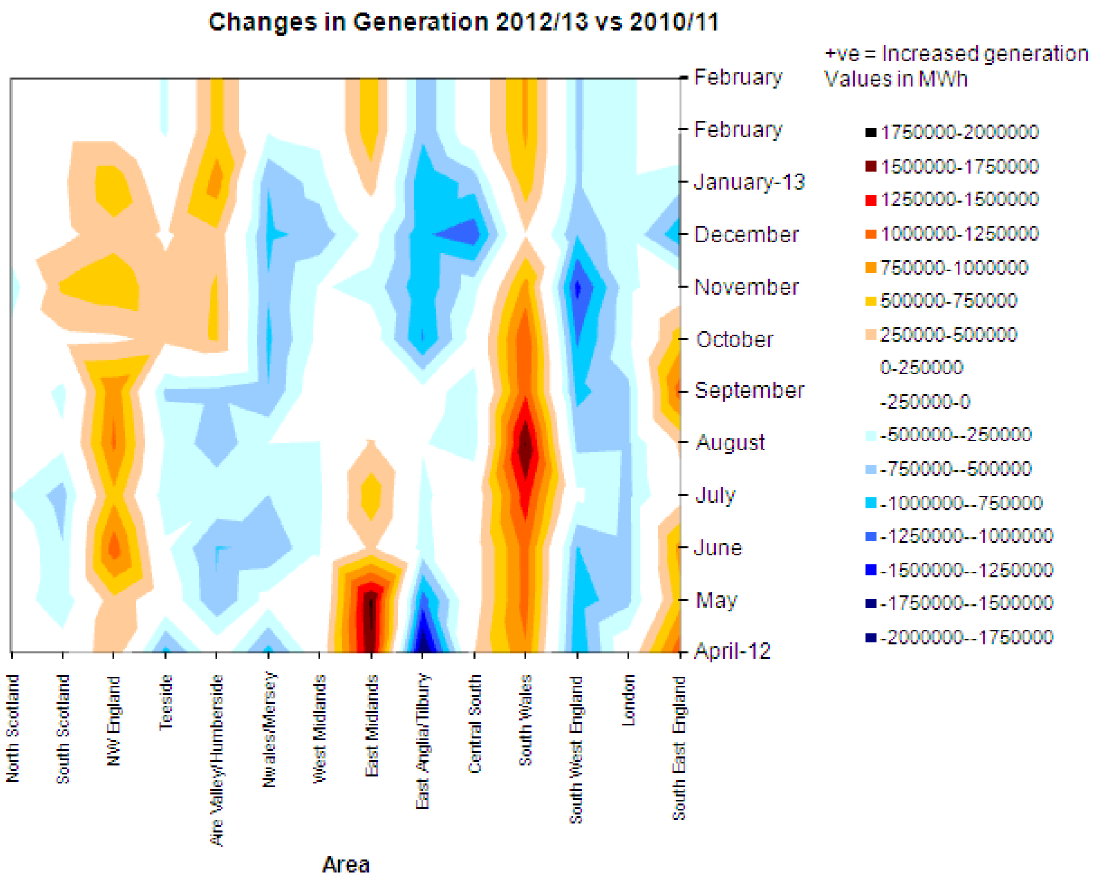

Figure 4: Heatmap of 2012/13 Generation Relative to Previous Year

Financial Impact

21 Transmission Losses do not directly enter the Balancing Services Use of System Charges (BSUoS). The only impact is via an alteration of National Grid's profit or loss under the incentive scheme as a whole.

22 Taking into account that Transmission Losses only affect performance against the scheme the net impact of Transmission Losses from 2005/6 to 2010/11 inclusive has been in the order of £0.6m. This has largely been due to being within the cap or collar in years where there has been a variance from the losses target or, in the case of 2006/7, no scheme being agreed.

23 For the 2011 to 2013 incentive scheme the impact, and therefore the income adjustment should this IAE be approved, is calculated as being £21m where no other amendments are made to the scheme target or cost outturn. This is shown in the table below.

Scheme Year	Tx Losses IBC (£m)	Scheme Target (£m)	Scheme Outturn (£m)	Scheme Outturn less TLIC (£m)	Upside Sharing Factor (%)	Downside Sharing Factor (%)	Cap (£m)	Collar (£m)	Target Deadband (+-£m)	P/L (Unadjusted) (£m)	P/L (Adjusted) (£m)	TLIC Incentive Impact (£m)
2005/6	-£ 5.48	£ 378	£ 427	£ 432	40	20	40	20	0	-9.9	-11.0	1.10
2006/7	£ 9.03	£ 495	£ 495	£ 486	0	0	0	0	0	0	0.0	0.00
2007/8	£ 2.33	£ 438	£ 451	£ 449	20	20	10	10	7.5	-1.2	-0.7	-0.47
2008/9	£ -	£ 537	£ 827	£ 827	25	25	15	15	7.5	-15	-15.0	0.00
2009/10	£ -	£ 615	£ 416	£ 416	25	15	15	15	15	15	15.0	0.00
2010/11	-£ 30.55	£ 539	£ 280	£ 311	15	15	15	15	0	15	15.0	0.00
Total 2005/6 to 2010/11												0.63
2011-13	£ 107.87	£ 1,503	£1,732	£1,624	25	25	50	50	5.0	-50	-29.1	-20.93

Figure 5: Incentive Costs of Transmission Losses

3. Modelling Transmission Losses

24 In April 2008 Ofgem wrote an open letter to National Grid directing National Grid to produce a report detailing the reasons for the rise in transmission losses over the period 2006 to 2007. As part of this report a new model was developed this showed that the increase in losses during this period could be explained by changes in the geographical distribution of generation, particularly reduced generation in the south west of England[3].

25 During 2009/10 these models were observed to breakdown and no longer reflect the losses being incurred. Further investigative work was carried out but was unable to find a consistent model which was robust both prior to this date and afterwards. Data integrity was confirmed with Elexon and ruled out as a cause of this discontinuity.

26 These models are statistical models and not physical models of the actual transmission network and electrical parameters there within. As such they are only capable of representing the relationships present within the training data. In all likelihood this discontinuity arose because of a driver present after this date which was not there beforehand, although none has as yet been singled out.

27 With no robust model of transmission losses available the target for 2011-13 was derived based on the observation of 2010/11 and expected increases in generation in the south of England and Wales.

New Models

28 Recognising that the geographical dispersion of generation is the key driver of transmission losses a new model has been built for the purposes of this submission. This new model is based on the outturn losses and regional generation outturn for incentive scheme years 2006/7 through to the end of 2008/9. Data from 2009/10 onwards can then be used as a comparator to check for the performance of the model.

29 A further model was also built taking a random sample of 40 months from April 2006 to March 2013. The performance of this model can then be compared to the other months which were not used as training data.

30 The performance of both models is illustrated in the chart and table below.

[3] http://www.nationalgrid.com/NR/rdonlyres/4D65944B-DE42-4FF4-88DF-BC6A81EFA09B/26920/ElectricityTransmissionLossesReport1.pdf

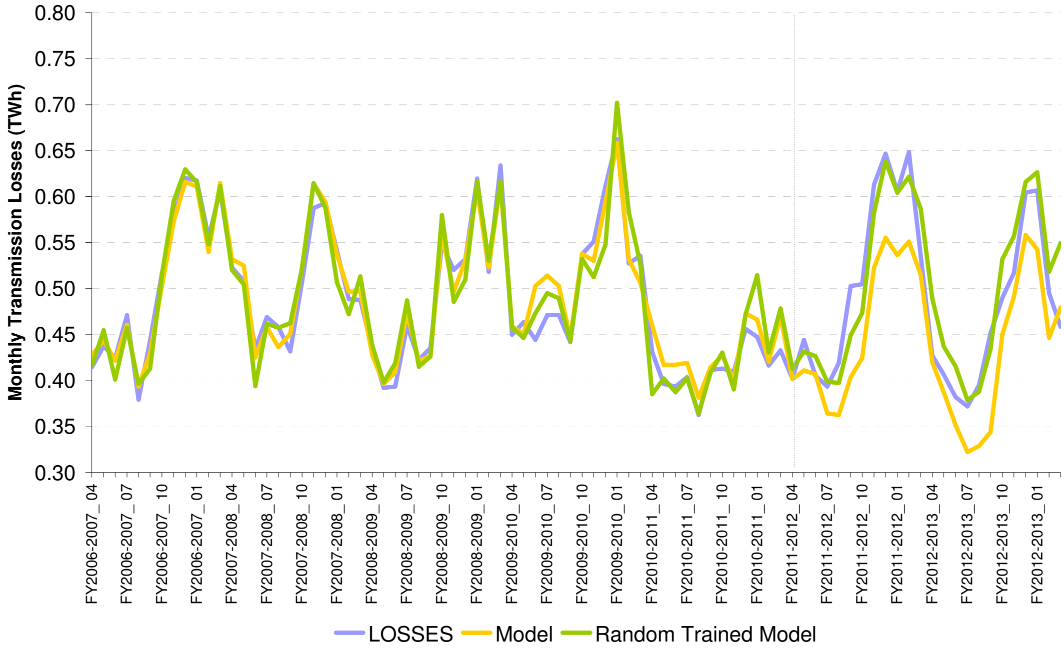

Figure 6: New Model Performance

Model	R^2	SE	MAE (Trained)	MAE (Predicted)	Number of Samples	F-Stat
Monthly Gen	0.9994	0.016	0.011	0.034	36	2516.2
Monthly Gen (Random Train)	0.9984	0.024	0.015	0.024	40	1192.2

Figure 7: Model Statistics

31 As can be seen both models achieve a good fit to the training data as indicated by the R^2 values above. The model trained on the newer data performs better when predicting ("Mean Absolute Error (Predicted)" in the table above) and is visibly picking up the increased losses within the current scheme. This indicates that the more recent data has information within it which was not present within the older dataset. Examples of this could be new generation connecting or impact of the increasing level of wind on the system.

32 Further analysis was undertaken to look at the statistical significance of the zonal generation coefficients. The key points to note from this are:

- As in the 2008 report, South West England has a strong statistical relationship to the losses. South-East England is also of strong significance.
- The values in the northerly areas (Scotland, Aire Valley & NW England) all show a strong significance in both models.
- The East Anglia and Tilbury region shows a substantial increase in significance between the two models (0.1 to 1.8)

33 These models support the conclusion that the variation in losses continues to be primarily driven by change in the geographical dispersion of generation, particularly increases in northern generation. They also show that the variation in the 2011/13 scheme is affected by hitherto unseen relationships between the location of generation and losses on the transmission system.

4. Actions taken to mitigate Costs of Transmission Losses

34 National Grid undertakes actions to balance energy and resolve system issues in an economic and efficient manner taking into consideration many different inputs and limitations of the physical plant and transmission system. These actions are very small by volume in comparison to the actions taken by the market as a whole, as shown in the table below for 2011/12.

2011/12	MWh
Total Generation	319,114,990
Total BM (ABS)	16,654,595
Total Trade Volume (Abs)	3,089,394
% NGET	6.2%

35 All other considerations being equal then National Grid would despatch the plant which would result in the lowest level of transmission losses, however this would require equal pricing between two options with no other system benefits being delivered such as the level of margin provided or resolving a locational issue e.g. a constraint.

36 As SO we can, in principle, alter power flows across the NETS and hence influence the volume of losses using the Balancing Mechanism (BM), where we can increase (Offer) or decrease (Bid) generation to balance the system. For example, we could accept Bids to reduce generation remote from demand centres such as that in the north of Scotland (namely wind power), and Offers to increase generation closer to demand centres; such as that located in the south of England (gas, coal or oil plant). However such actions are not consistent with our licence obligations and whilst reducing losses, could be regarded as also inconsistent with Government objectives of a de-carbonised energy sector.

37 Our transmission licence requires us to co-ordinate and direct flows onto and over the transmission system in accordance with the NETS Security and Quality of Supply Standards (SQSS), taking only price and technical differences into account in choosing between providers of balancing actions. This does not permit balancing actions to be taken solely to reduce transmission losses. Instead, having taken transmission system security and generator technical characteristics into account, balancing actions must be taken in strict price order.

38 Even if we were permitted to re-despatch the system taking account of losses, the scope for reducing losses economically in this manner is extremely limited. The marginal cost of accepting a Bid to reduce output at plant remote from demand centres and accepting an Offer to increase output at plant located closer to demand centres, will in the vast majority of cases, be higher than the savings in losses this would achieve, even taking into account the cost of carbon. We therefore believe the scope for re-despatching plant economically to reduce losses is extremely limited.

39 To demonstrate this point, the losses model described above has been used with the annual zonal generation data from 2009/10 and Excel's Solver function to:

- minimise first the losses;
- losses but with a minimum generation requirement in one zone (to simulate a system constraint);

- losses but taking no more than 6% of the total generation volume; and
- optimising on losses & cost simultaneously.

40 All Bids were assumed to be at £25/MWh and all Offers to be at £75/MWh. Limitations were placed on the Solver routine such that:

- Total generation before and after had to be the same;
- Bid volume in any zone could not exceed the starting generation; and
- Offer volume could not exceed the difference between the starting generation and the sum of MEL in that region

41 The results of these are shown in the table below

	Initial Losses	Losses	Cost (£m)
Losses Only	6.08	-0.36	4,274
Losses Only, Min Gen in Scotland	6.08	-0.37	4,680
Losses Only, Vol capped at 6%	6.08	5.01	442
Losses + Cost	6.08	6.08	0

42 As can be seen from the table above the model suggests that losses could be reduced to zero, whilst not physically possible, at a cost of £4.3 billion. Imposing a simple system constraint increased this to £4.7 billion. Capping the volume at the 6% which National Grid takes in the real world would allow for a reduction in losses of 1TWh, but at a cost of £442 million. Finally including cost[4] in the optimisation as well shows that there is no change in losses.

43 Whilst this is a very simplified view of how changing generation to minimise losses would impact on costs it does clearly demonstrate that efforts to do so would have a high and disproportionate cost impact to the industry and consumers.

44 For the next incentive scheme commencing from 1st April 2013 the transmission losses financial incentive on the System Operator has been removed by Ofgem in recognition that the SO has a low degree of control over the level of losses on the NETS.

5. Reasons why this is an Income Adjusting Event

45 As shown in the sections above, the identified drivers of losses coupled with the framework in which National Grid operates means that the SO has very limited control over their volume. This has been corroborated by Ofgem's decision to remove the Transmission Losses financial incentive from the 2013-15 incentive schemes. As shown in section 4 there is very little that can be done by National Grid to efficiently reduce transmission losses as such there is not a practical mechanism by which the system operator can manage these costs.

46 No predictive model of transmission losses on the GB system existed at the time this scheme was agreed due to the breakdown of previous models. As

[4] Cost calculated as loss volume x £47/MWh + Cost of Bids and Offers

shown in section 3 there is also a variance in the behaviour of models trained on the older data and those train including of the current scheme years.

47 Had the model trained on older data existed prior to the 2011-13 scheme being agreed it would have forecast losses of 10.55TWh against actual losses of 12.11TWh if, and only if, the generation was also forecast as has happened in reality. This would still fall outside the transmission losses scheme forecast deadband.

48 In the absence of a target deriving model, the assumptions made when setting the 2011-13 target proved to be inaccurate as new southern generation did not commission within forecast timescales and spark spreads changed such that gas generation reduced. These factors were not within the control of the SO and as shown above, it is not economic for the SO to take actions to reduce losses.

49 In previous schemes the impact of transmission losses on the System Operator has always been low due to the design of the losses scheme, particularly the deadband, or through the costs of the scheme as a whole being deep within the cap or collar. However within this scheme the transmission losses are causing the overall costs to be within the collar and hence weakened the incentive on National Grid in areas over which the SO has greater control. At a total cost impact of £107.9m this exceeds the income adjusting event trigger threshold of £2m.

6. Appendix 1: Modelling of Transmission Losses

50 This section sets out how transmission losses have been modelled to understand and demonstrate how the geographical dispersion of generation has affected transmission losses.

Model 1: Regional Monthly Generation

51 Recognising that the geographical dispersion of generation is the key driver of transmission losses a new model has been built. This new model is based on the outturn losses and regional generation outturn for incentive scheme years 2006/7 through to the end of 2008/9. Data from 2009/10 onwards can then be used as a comparator to check for the performance of the model. All data is sourced from the Elexon SAA-IO14 data flow. Model coefficients were derived via Excel's "Linest"[5] function.

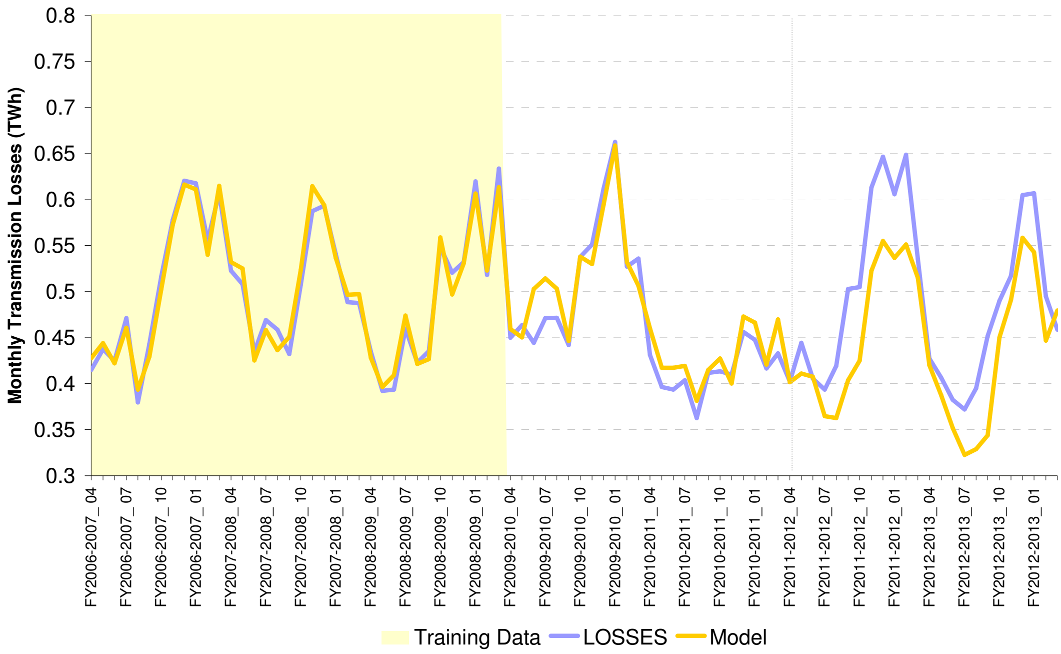

Figure 8: Monthly Regional Generation Model

Model	R^2	SE	Mean Absolute Error (Trained)	Mean Absolute Error (Predicted)	Number of Samples	F-Stat
Monthly Gen	0.9994	0.016	0.011	0.034	36	2516.2

Figure 9: Model Performance Statistics

52 As can be seen from the graph and statistics above this model produces a good fit over both the training period (2006/7-2008/9) and for the data up to April 2011. After April 2011 the model generates the same shape but is not of the same magnitude as that observed in reality.

Model 2

53 A second model was trained on the same data but taking a random sample of data points from across the observed history.

[5] Excel uses the Ordinary Least Squares method within this function

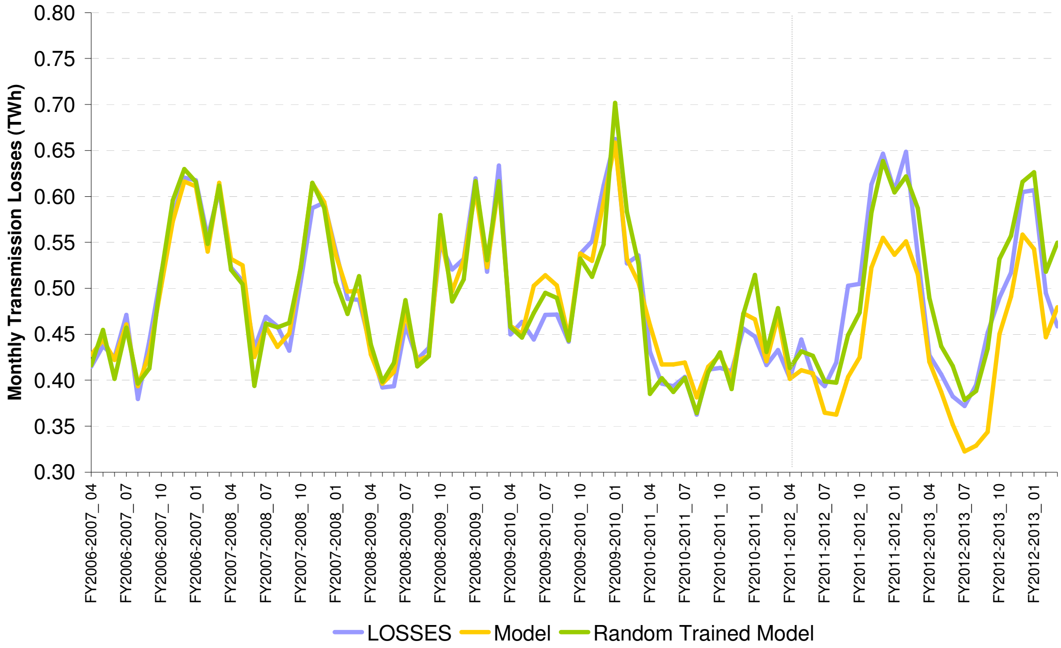

Figure 10: Monthly Regional Generation Model, with random samples

Model	R^2	SE	MAE (Trained)	MAE (Predicted)	Number of Samples	F-Stat
Monthly Gen	0.9994	0.016	0.011	0.034	36	2516.2
Monthly Gen (Random Train)	0.9984	0.024	0.015	0.024	40	1192.2

Figure 11: Randomly Trained Model Statistics

54 As can be seen from the table the use of a random draw of samples lowers the R^2 and F-Stat values from which the model can be judged however the data picked from the later years provides an improved fit particularly post-April 2011.

55 The conclusion from this is that the later observations contain relationships that were not apparent in the earlier data, such as new generation connections or changes in prevailing market conditions, which are having an effect.

Significance Test

56 A standard test for the statistical significance of a coefficient is to calculate the T-Stat for that coefficient. The table below compares the T-stats[6] for the coefficients in the two models. This provides an insight in to the zones which are most significant with relation to losses, particularly in terms of the improvement to the randomly trained model. The green highlighted cells show those coefficients which pass a test for statistical significance[7].

[6] Coefficient/standard error. This is usually low when the coefficient is insignificantly different from a zero value.

[7] Absolute value of coefficient/standard error >= t-critical

T-Test	North Scotland	South Scotland	Aire Valley/Humberside	South West England	South Wales	South East England	Central South	NW England	Teesside	West Midlands	Nwales/Mersey	London	East Midlands	East Anglia/Tilbury
20067-2008/9 Train	2.5	7.5	7.1	4.6	2.0	3.4	1.4	2.2	2.9	1.3	1.6	0.4	2.5	0.1
Random Train	3.5	5.4	6.4	6.1	1.0	2.0	0.6	4.1	0.7	1.0	0.9	0.2	2.3	2.1

Figure 12: T-Stats Comparison

57 The key points to note in the table above are that

- As in the 2008 report, South West England has a strong statistical relationship to the losses. South-East England is also of strong significance.
- The values in the northerly areas (Scotland, Aire Valley & NW England) all show a strong significance in both models.
- The East Anglia and Tilbury region, shows a substantial increase in significance between the two models (0.1 to 1.8)

58 This supports the conclusion that the increased losses have primarily been driven by change in the geographical dispersion of generation, particularly increases in northern generation.

59 The table below shows the coefficients derived for each zone in the two models. What this means in real terms is that transferring 1TWh of generation per year[8] from the South West to the SHETL area (North Scotland) would be expected to increase losses by 0.12TWh within the randomly trained model.

Coefficients	North Scotland	South Scotland	Aire Valley/Humberside	South West England	South Wales	South East England	Central South	NW England	Teesside	West Midlands	Nwales/Mersey	London	East Midlands	East Anglia/Tilbury
20067-2008/9 Train	0.030	0.066	0.039	-0.045	-0.032	-0.023	-0.018	0.032	0.045	0.026	0.021	-0.009	0.019	0.001
Random Train	0.055	0.072	0.056	-0.067	-0.001	-0.027	-0.010	0.052	0.027	0.019	-0.019	-0.012	0.020	-0.012

Model 3

60 Having looked at monthly generation the same was attempted on daily values. As this increases the number of data points this should provide more information on the relationships there within. The values returned from this, summated monthly, are shown in the graph below. The tables that follow show the model statistics and comparison to the model based on monthly values.

[8] Equivalent to circa 114MW in every hour of the year

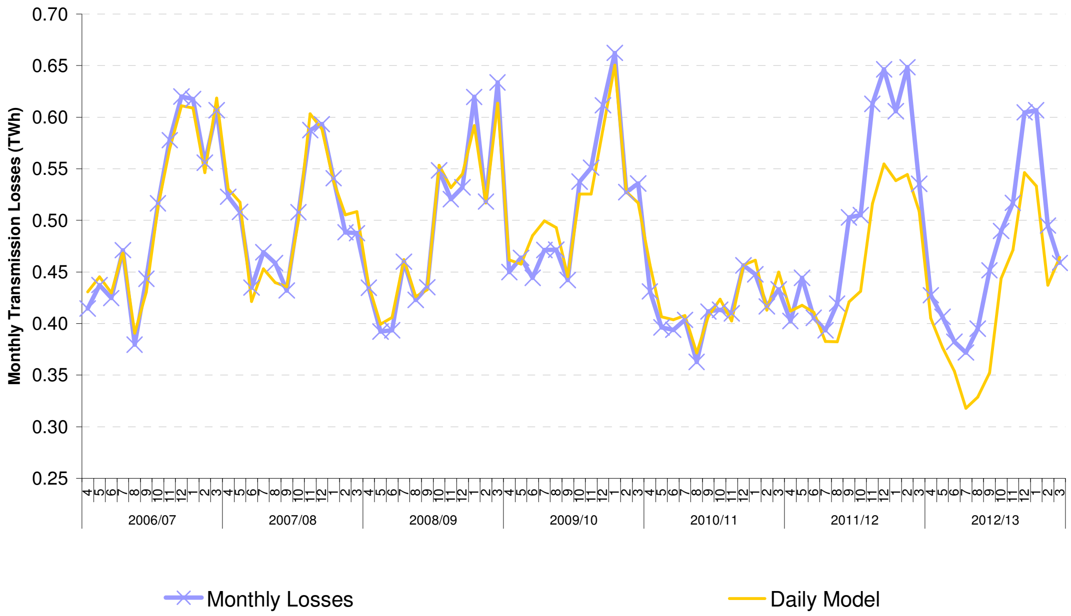

Figure 13: Monthly Modelled Loses based on Daily data

Model	R^2	SE	Mean Absolute Error (Trained)	Mean Absolute Error (Predicted)	Number of Samples	F-Stat
Daily Gen	0.997	0.001	0.001	0.001	1096	30152

Figure 14: Daily Model Statistics

Coefficients	North Scotland	South Scotland	Aire Valley/Humberside	South West England	South Wales	South East England	Central South	NW England	Teeside	West Midlands	NWales/Mersey	London	East Midlands	East Anglia/Tilbury
Monthly Gen	0.030	0.066	0.039	-0.045	-0.032	-0.023	-0.018	0.032	0.045	0.026	0.021	-0.009	0.019	0.001
Daily Gen	0.075	0.056	0.039	-0.036	-0.027	-0.022	-0.019	0.033	0.042	0.020	0.019	-0.020	0.013	0.000

Figure 15: Comparison of coefficients

61 As can be seen from the graph the model based on daily values continues to perform well, but is still unable to predict the magnitude of the losses in 2011-13. The additional data does correct for some anomalies in the monthly model, namely that the north of Scotland is now seen as giving rise to higher losses than southern Scotland. This now fits with the intuitive expectation that the further power is injected from the demand centres of south-east England, the greater the losses.

Daily Generation, random samples

62 As was carried out for the monthly generation models, a random draw of samples was taken from the daily values across all the data and used as to produce a new model. As seen in the monthly model, the inclusion of later

data provides information which allows for the increased losses seen in 2011 to 2013 to be picked up. For the daily model 1/3 of samples where used with the remaining 2/3 available for comparison.

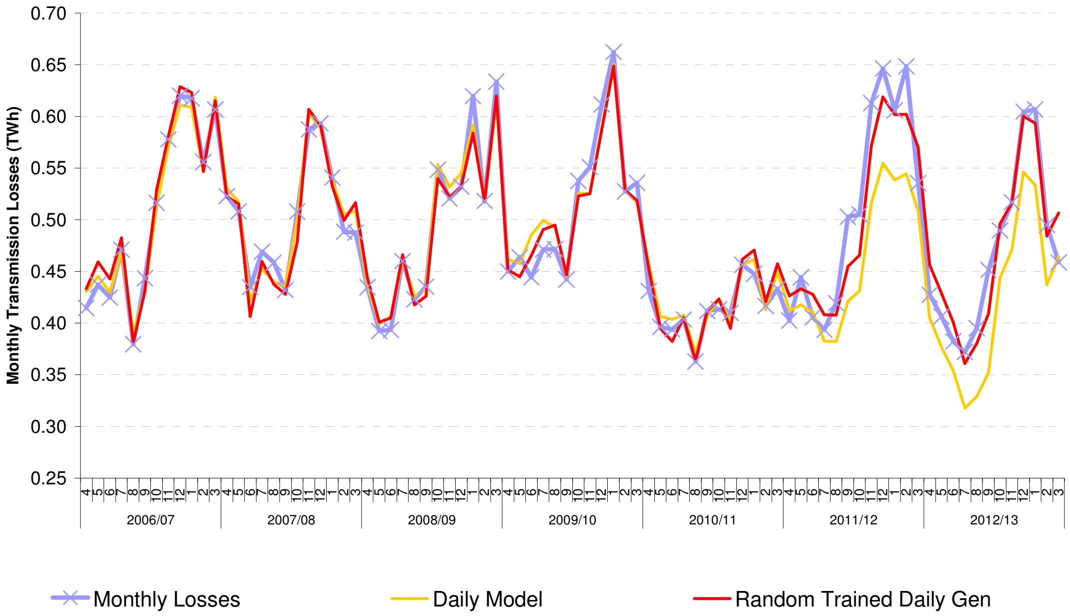

Figure 16: Daily models summated to monthly

Model	R^2	SE	Mean Absolute Error (Trained)	Mean Absolute Error (Predicted)	Number of Samples	F-Stat
Daily Gen	0.997	0.001	0.001	0.001	1096	30152
Random Sampled Daily Gen	0.992	0.001	0.001	0.003	833	7087

Figure 17: Random Sample Model Statistics

Daily Variation Models

63 The models described above show the relationship between gross generation and losses. This also contains seasonal information and demand by the proxy of total generation. A method to verify that the change in generation is a driver of transmission losses is to build the model on the delta value between days rather than the gross value and compare this to the delta value in losses. The graph below shows the results of this, again summated monthly, with the model statistics presented in a table below. A second variation on this model was also produced incorporating delta demand in addition to the generation. This is also shown below. The coefficients for these models can be found in the table at the end of this appendix.

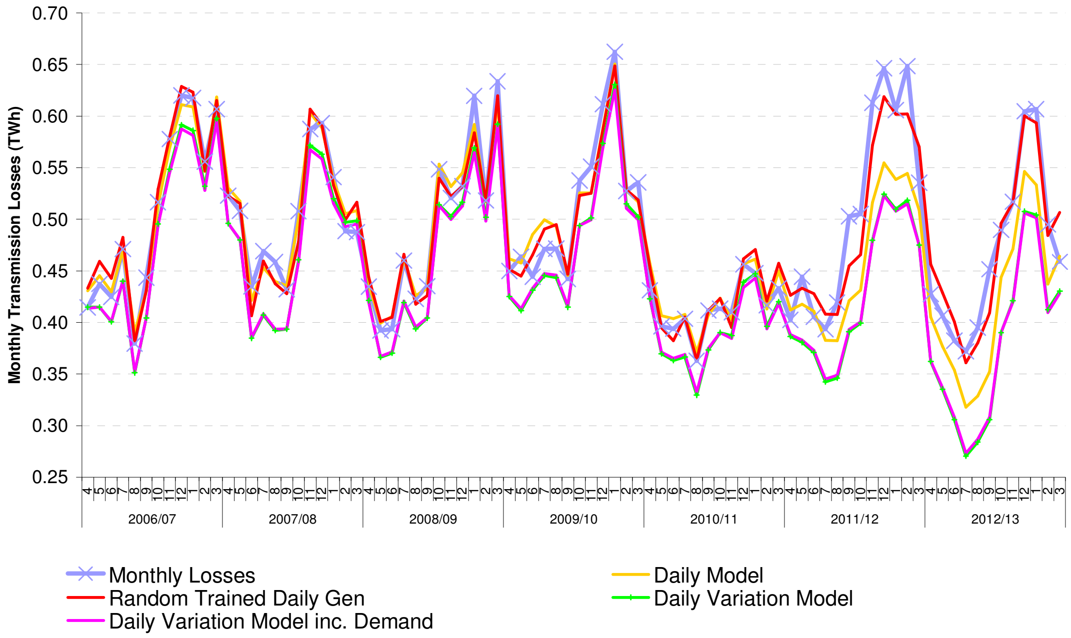

Figure 18: Graph of monthly total losses

64 As can be seen in the graph above the addition of demand adds very little information to the model with the line overlapping almost entirely with the generation only model. This further strengthens the evidence that the variation in losses is generation lead.

65 Further we can see that the daily variation models derived from 2006/7 to 2008/9 data fail to pick up the magnitude of losses in 2011/12 and 2012/13.

	Demand	North Scotland	South Scotland	Aire Valley/Humberside	South West England	South Wales	South East England	Central South	NW England	Teeside	West Midlands	Nwales/Mersey	London	East Midlands	East Anglia/Tilbury	Const
Daily Gen	N/A	0.075	0.056	0.039	-0.036	-0.027	-0.022	-0.019	0.033	0.042	0.020	0.019	-0.020	0.013	0.000	0.000
Random Sampled Daily Gen	N/A	0.103	0.064	0.039	-0.048	-0.018	-0.023	-0.011	0.049	0.043	-0.004	0.014	-0.049	0.016	-0.013	0.000
Daily Variation	N/A	0.097	0.056	0.039	-0.020	-0.023	-0.016	-0.019	0.037	0.044	0.008	0.031	-0.007	0.017	-0.001	0.000
Daily Variation inc. Demand	-0.001	0.098	0.056	0.039	-0.020	-0.022	-0.016	-0.018	0.038	0.044	0.009	0.032	-0.006	0.018	0.000	0.000

Figure 19: Coefficients of daily models

T-Stats	Demand	North Scotland	South Scotland	Aire Valley/Humberside	South West England	South Wales	South East England	Central South	NW England	Teeside	West Midlands	Nwales/Mersey	London	East Midlands	East Anglia/Tilbury
Daily Gen	N/A	19.516	32.833	36.824	-16.190	-10.519	-18.566	-8.842	12.479	14.953	6.304	9.726	-4.107	8.808	-0.293
Random Sampled Daily Gen	N/A	17.189	18.356	18.004	-12.893	-4.970	-10.456	-2.874	12.784	9.690	-0.593	3.721	-5.822	6.473	-4.846
Daily Variation	N/A	14.867	16.091	21.401	-4.100	-5.556	-7.379	-5.516	4.122	5.706	1.756	10.353	-0.679	7.789	-0.283
Daily Variation inc. Demand	-0.957	14.872	15.865	19.770	-3.864	-5.214	-6.487	-5.104	4.193	5.776	1.907	10.212	-0.588	7.578	0.025

Figure 20: T-Stats of Daily Models

Note: Shaded cells are those which have <5% chance of being due to chance i.e. they are statistically significant.