Demand Forecasting
Reporting Period: 11th Sep 2017 – 3rd Dec 2017

EXECUTIVE SUMMARY

This report provides an overview of national demand, solar and wind forecast errors for the reporting period between the 11th of September 2017 and 3rd of December 2017, and the work currently underway by National Grid to reduce these errors. The magnitude of these errors is discussed at the different lead times of within day, day ahead, 2-14days ahead and 2-52 weeks ahead.

For our demand forecasts, the daytime cardinal point errors tended to improve slightly at the day ahead and two day ahead forecast horizons. The overnight cardinal point forecasts generally worsened between the last reporting period and this one.

Wind generation forecasting was challenging during this reporting period. Our average forecasting error after bid-offer-acceptances (BOAs) has increased compared with the previous three months. Our wind forecasts were also typically below outturn. At the end of November however we completed a significant update to the majority of our transmission connected wind power forecasting models, which should help manage the error going forward.

Work continues on our internal projects and on our NIA-funded projects to support and improve our forecasting performance.

INTRODUCTION

Under section 4H of the Transmission Licence, National Grid is obliged to publish a quarterly report describing our demand, wind and solar generation forecasts from within-day to 52 weeks ahead. We are also required to describe the actions that we have taken that have affected forecast errors and an analysis of the causes and future actions to reduce these errors.

This quarterly report contains an overview of the differences between national demand, wind and solar forecasts and their outturns with different lead-in times during the Qtr. 3 reporting period 11th of September 2017 to 3rd of December 2017. Reporting times for Qtr. 1 and Qtr. 2 were 1st of April 2017 to 18th June 2017, and 19th June 2017 to 10th September 2017 respectively.

Some key demand outturns of the Qtr.3 reporting period are given in the table below.

Key Numbers	Date	Half hour	Power (GW)
Peak Demand	13th Nov 17	1730	47.3
Overnight minimum	2nd Oct 17	0430	17.1
Daytime minimum	22nd Oct 17	0900	24.3
Maximum PV output	22nd Sep 17	1230	6.3

The overnight minimum demand was the lowest ever observed for the month of October. The previous October record was 19.3 GW in 2016.This is a significant drop and due in particular to the contribution from embedded wind as well as mild overnight temperatures.

At the end of this reporting period, installed capacities for wind and solar reached 30.5GW. This is 1.9GW higher than reported at the end of the previous quarter. The greatest increase was reported for metered wind capacity at 0.9GW. Embedded wind and solar capacities, which directly affect our demand forecasts, increased by 1GW.

Generation Type	Capacity (GW)
Metered Wind	11.8
Embedded Wind	5.8
Embedded Solar	12.9
Total Wind & Solar	30.5

This report focuses mainly on the national electricity demand (national demand/INDO equivalent) forecasts and its' major components:

- Embedded PV generation
- Embedded wind generation
- Weather forecast input data

We also report on the metered wind generation forecasting performance, as well as report on the work we have undertaken to improve both demand and wind generation forecasts.

Special attention is paid to the incentivised forecasts, made one, two and seven days ahead.

DEMAND FORECAST ERRORS

We produce forecasts at multiple time horizons, from within day up to five years ahead. Overall we typically produce over 100 forecasts for the peak demand on a particular day over the preceding five years. In this report special attention is paid to forecasts made one, two and seven days beforehand. These forecasts are subject to OFGEM's demand forecasting incentive scheme.

Forecasts at greater than 14 days ahead are based on seasonal average weather, whilst those from within day to 13 days ahead use the latest available weather forecasts. It should be noted that most weather forecast models run from 0 to 6 days ahead, and that the accuracy of weather forecasts decreases significantly from 7 to 13 days ahead.

The table below shows the mean absolute error by cardinal points and by forecast lead-time. The forecast range stretches from in-day forecasts to 13 days ahead.

With forecast lead-time increasing (i.e. a forecast projecting further into the future), the errors grow as can be expected.

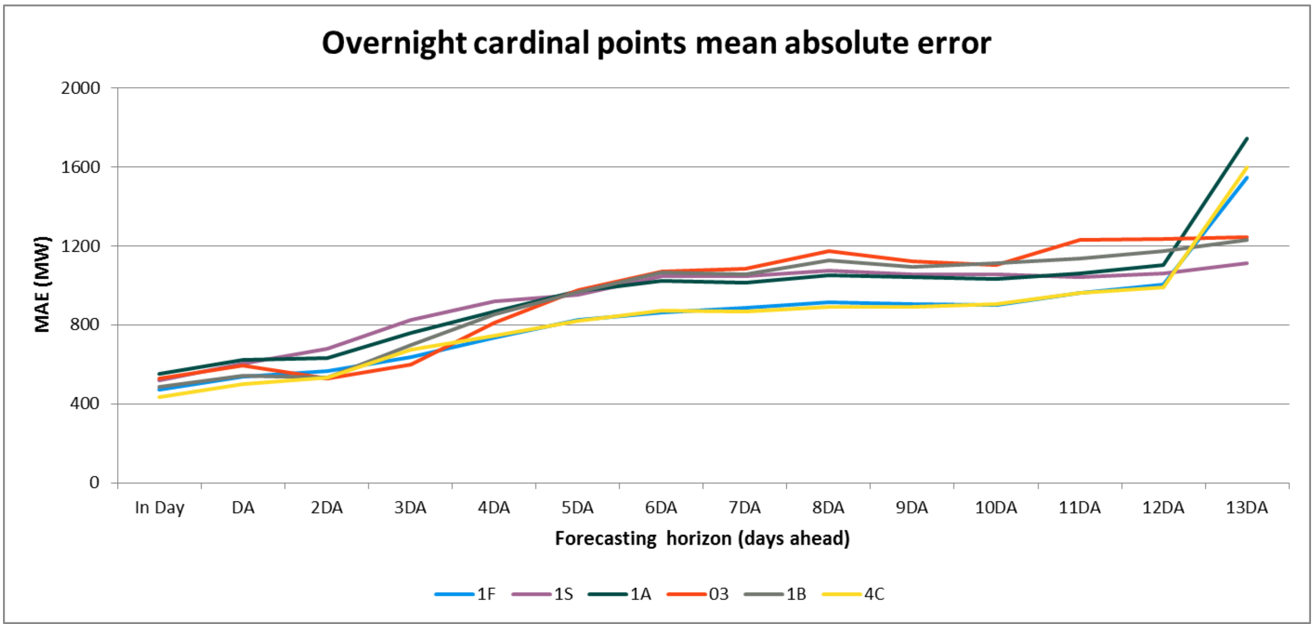
In comparison with Qtr. 2, the mean absolute error (MAE) for most of the overnight cardinal point forecasts increased. The daytime cardinal points mostly stayed at a very similar level or slightly improved. For the evening cardinal points there was a small increase in MAE. MAE of all of the cardinal points increases with the forecast lead time.

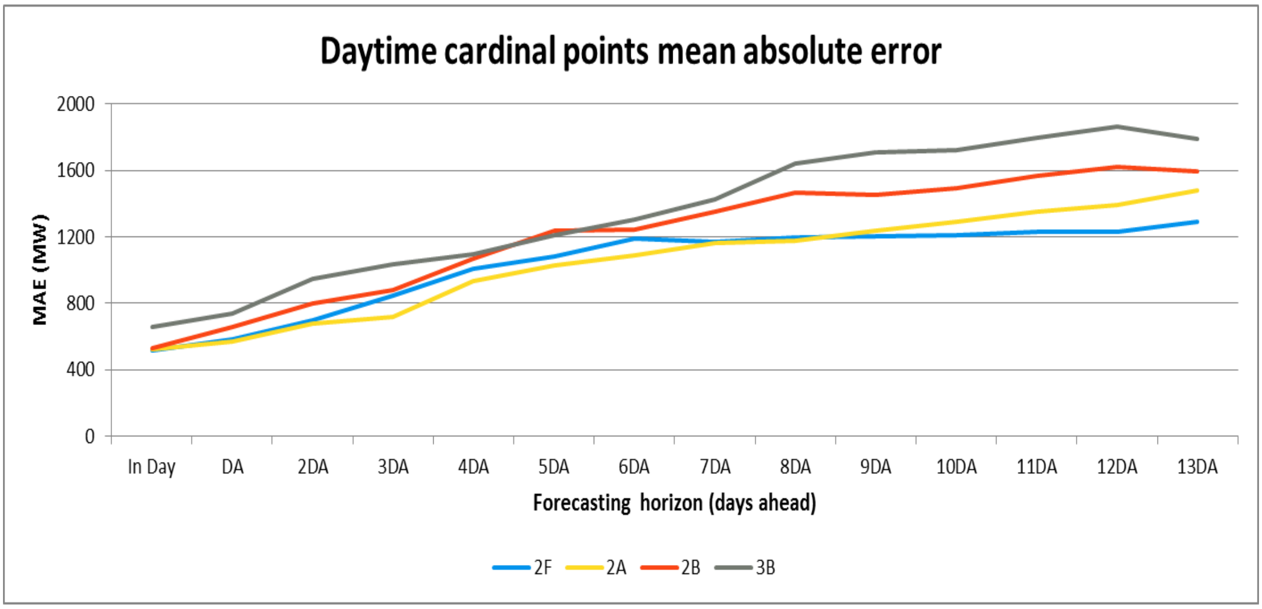
CPID	In Day	DA	2DA	3DA	4DA	5DA	6DA	7DA	8DA	9DA	10DA	11DA	12DA	13DA
1F	474	539	565	636	738	825	861	886	916	905	901	962	1005	1544
1S	520	603	678	827	921	954	1049	1049	1074	1057	1054	1043	1059	1111
1A	553	625	633	760	869	973	1023	1012	1053	1044	1031	1062	1105	1742
03	529	593	527	597	810	974	1069	1084	1172	1121	1105	1230	1234	1246
1B	488	543	532	698	856	969	1065	1055	1126	1095	1113	1137	1174	1229
2F	514	584	699	847	1007	1081	1188	1166	1198	1201	1209	1228	1227	1293
2A	525	569	678	720	936	1026	1089	1160	1175	1233	1289	1354	1390	1478
2B	526	654	796	880	1069	1234	1245	1351	1464	1450	1495	1566	1620	1596
3B	659	735	946	1033	1096	1212	1304	1427	1643	1708	1720	1793	1860	1786
3C	455	739	780	1138	1058	1089	1154	922	1084	1113	1099	1028	1098	1523
DP	394	624	732	721	825	916	1018	1189	1539	1551	1505	1439	1442	1229
4A	488	730	726	1107	1098	1161	1336	900	1186	1222	1214	1214	1356	1685
4B	423	479	497	658	773	861	945	971	988	1039	1034	1090	1107	1078
4C	436	500	535	674	745	822	874	867	893	891	905	963	991	1596

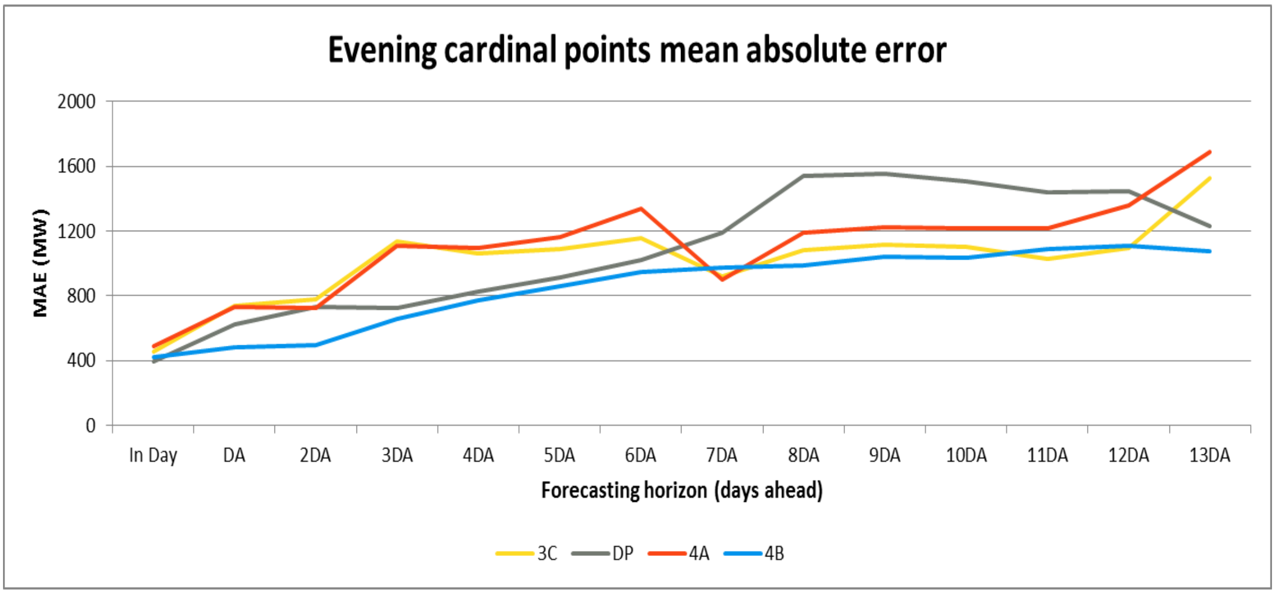
errors < 500	500≤errors<600	600≤errors<800	800≤errors≤1000	errors > 1000

The major components of the demand forecast and hence demand forecast errors are explained in detail in Appendix 1.

The graphs below show how the mean absolute error for each cardinal point forecast changed with forecast horizon, from 0 to 13 days ahead. The data is broken into forecasts for the overnight, daytime and evening cardinal points. The data shows that the errors increase at greater time horizons.







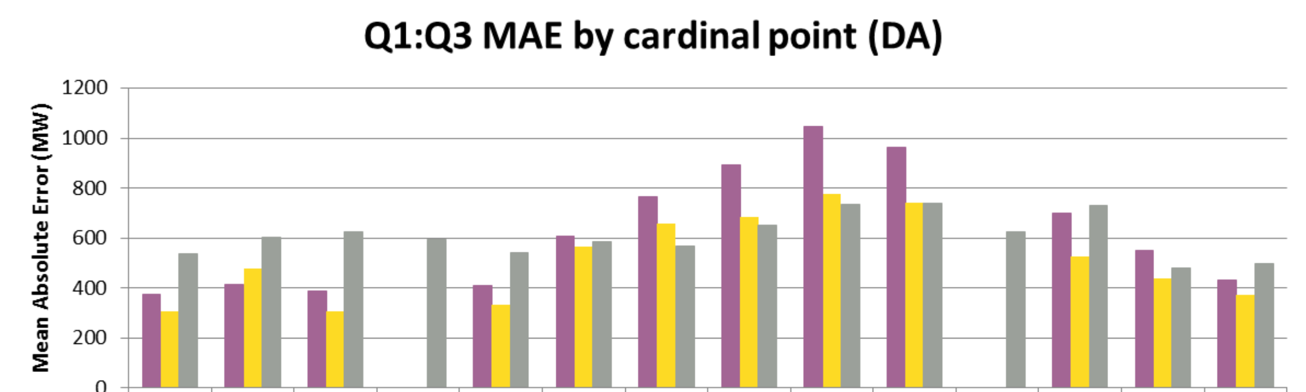
Notable in these graphs is the drop in mean absolute error for the cardinal points 3C and 4A for the 7DA forecasts onwards. This drop is larger than in the previous Quarter. These cardinal points were only active during the first part of the reporting period and are at the end of the daylight period where demands are particularly sensitive to PV generation and brightness. The solar radiation forecasts that we receive have a structural difference from day 7 onwards, in that coarser and fewer underlying radiation models are available and in use from this forecast horizon. We believe this to be one of the key drivers for the step change observed from 7 days onwards for these cardinal points. For the 7DA ahead forecast, particular care is taken at this forecast horizon for these cardinal points.

INCENTIVISED DEMAND FORECASTS

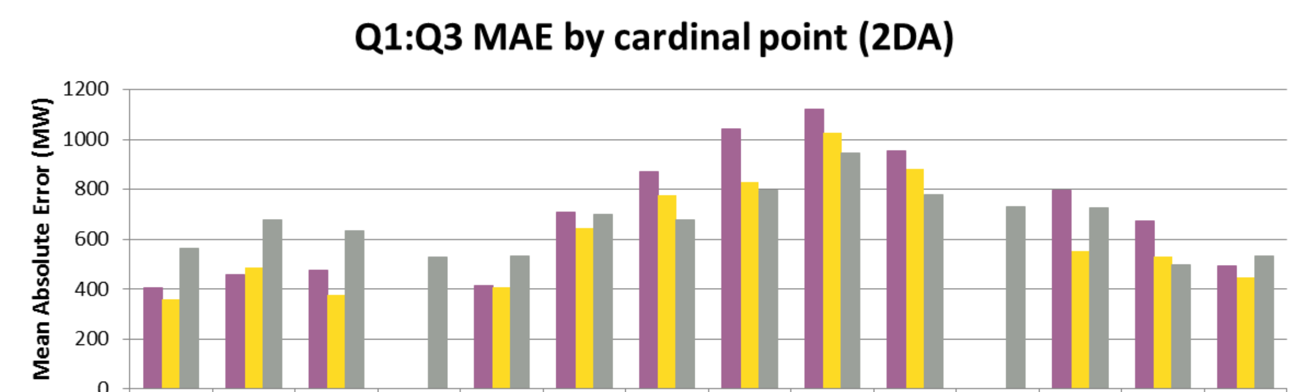
This section of the report shows a comparison between the previous quarters (Qtr.1 & Qtr.2) and the current quarter (Qtr.3) for the incentivised demand forecasts, - day ahead (DA), 2 days ahead (2DA) and 7 days ahead (7DA).

We continually try to improve the performance of our forecasting models against a background of increasing uncertainty. The first set of 3 graphs below shows quarterly MAE for each of the incentivised timescales.

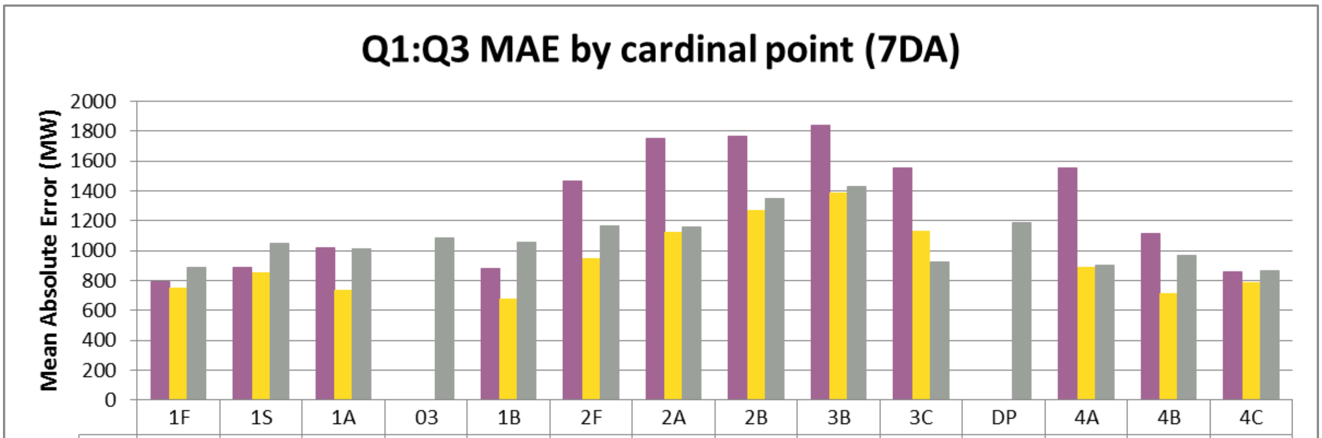
The DP cardinal point errors in the final full month of Qtr. 3 (Nov 2017) are increased by the effect of triad avoidance actions, as the forecasts are required to be made without taking these actions to account while the out turn does take these actions to account.



	1F	1S	1A	03	1B	2F	2A	2B	3B	3C	DP	4A	4B	4C
Q1	374	415	389	0	410	608	764	892	1048	962	0	700	553	431
Q2	309	477	309	0	334	568	657	685	777	741	0	528	439	374
Q3	539	603	625	593	543	584	569	654	735	739	624	730	479	500

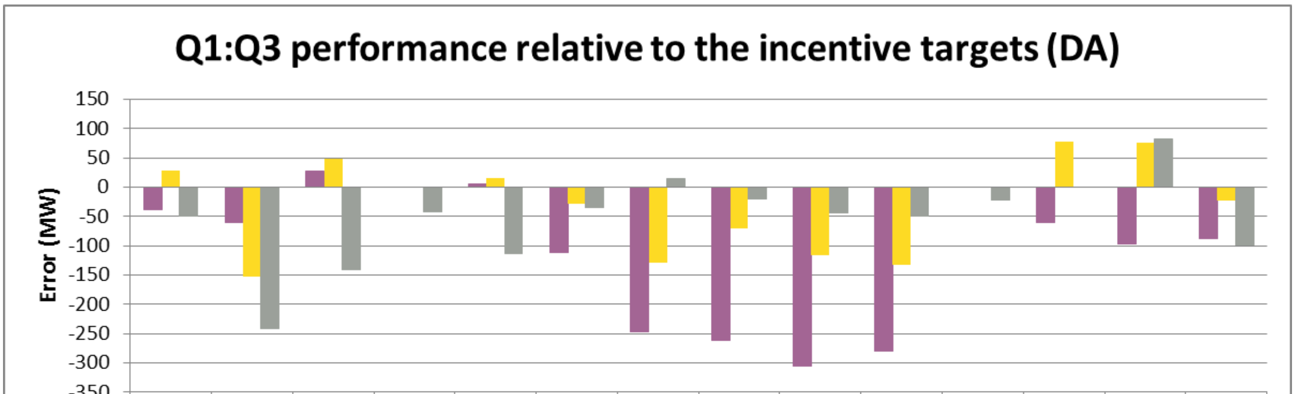


	1F	1S	1A	03	1B	2F	2A	2B	3B	3C	DP	4A	4B	4C
Q1	408	458	476	0	416	711	872	1041	1123	955	0	796	672	493
Q2	358	486	378	0	410	647	776	831	1026	883	0	551	530	446
Q3	565	678	633	527	532	699	678	796	946	780	732	726	497	535

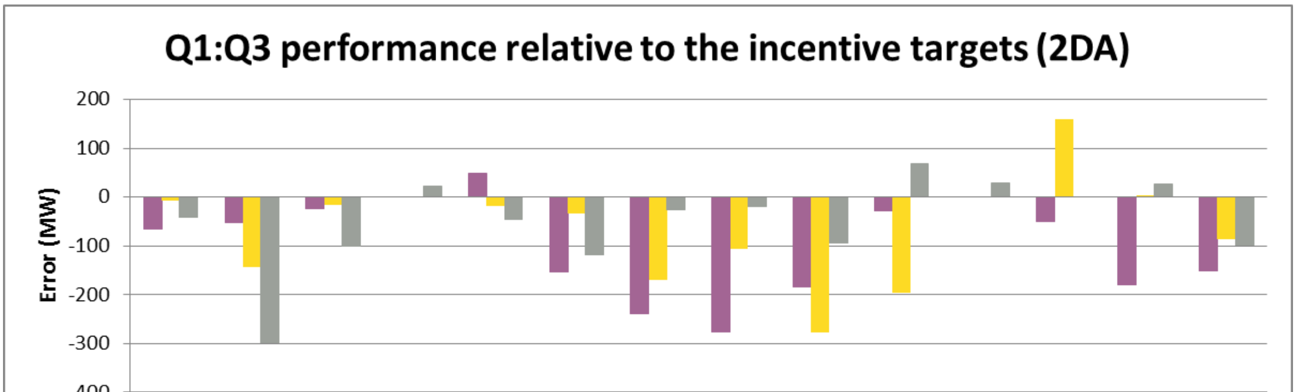


	1F	1S	1A	03	1B	2F	2A	2B	3B	3C	DP	4A	4B	4C
Q1	796	892	1021	0	881	1470	1756	1765	1842	1558	0	1553	1116	861
Q2	756	857	737	0	682	949	1130	1272	1387	1135	0	896	720	790
Q3	886	1049	1012	1084	1055	1166	1160	1351	1427	922	1189	900	971	867

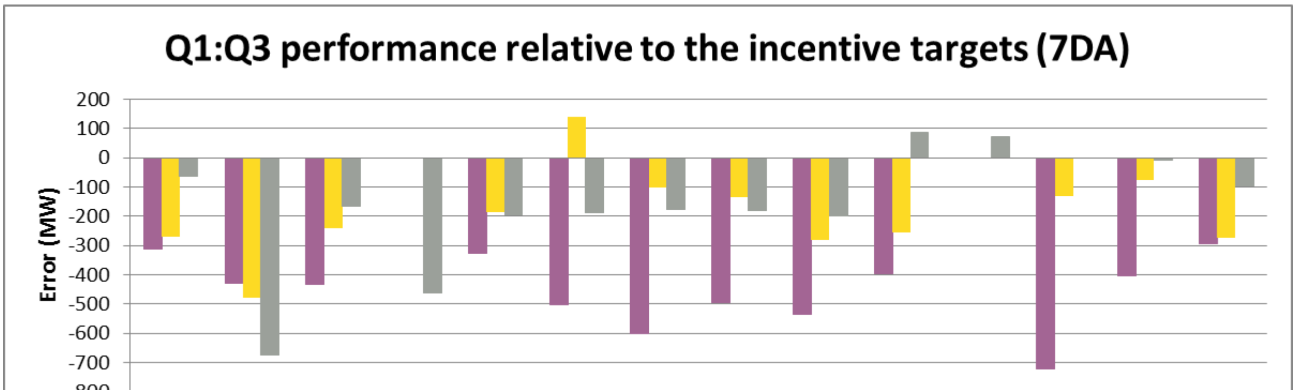
The following 3 graphs present the performance of the forecasts relative to the forecasting incentive targets for each timescale.



	1F	1S	1A	03	1B	2F	2A	2B	3B	3C	DP	4A	4B	4C
Q1	-39	-60	27	0	5	-111	-246	-262	-306	-280	0	-60	-96	-87
Q2	29	-153	49	0	15	-29	-129	-70	-116	-133	0	78	77	-23
Q3	-50	-241	-141	-42	-113	-35	15	-20	-43	-49	-21	0	83	-98



	1F	1S	1A	03	1B	2F	2A	2B	3B	3C	DP	4A	4B	4C
Q1	-66	-53	-23	0	48	-153	-238	-277	-184	-28	0	-49	-179	-151
Q2	-8	-144	-15	0	-19	-34	-170	-105	-278	-195	0	160	4	-87
Q3	-42	-299	-101	23	-45	-117	-25	-19	-93	69	30	0	27	-98



	1F	1S	1A	03	1B	2F	2A	2B	3B	3C	DP	4A	4B	4C
Q1	-311	-427	-432	0	-326	-501	-602	-496	-535	-395	0	-720	-403	-295
Q2	-270	-478	-241	0	-184	139	-100	-133	-279	-254	0	-129	-76	-274
Q3	-63	-674	-164	-462	-193	-187	-177	-180	-198	87	73	0	-9	-97

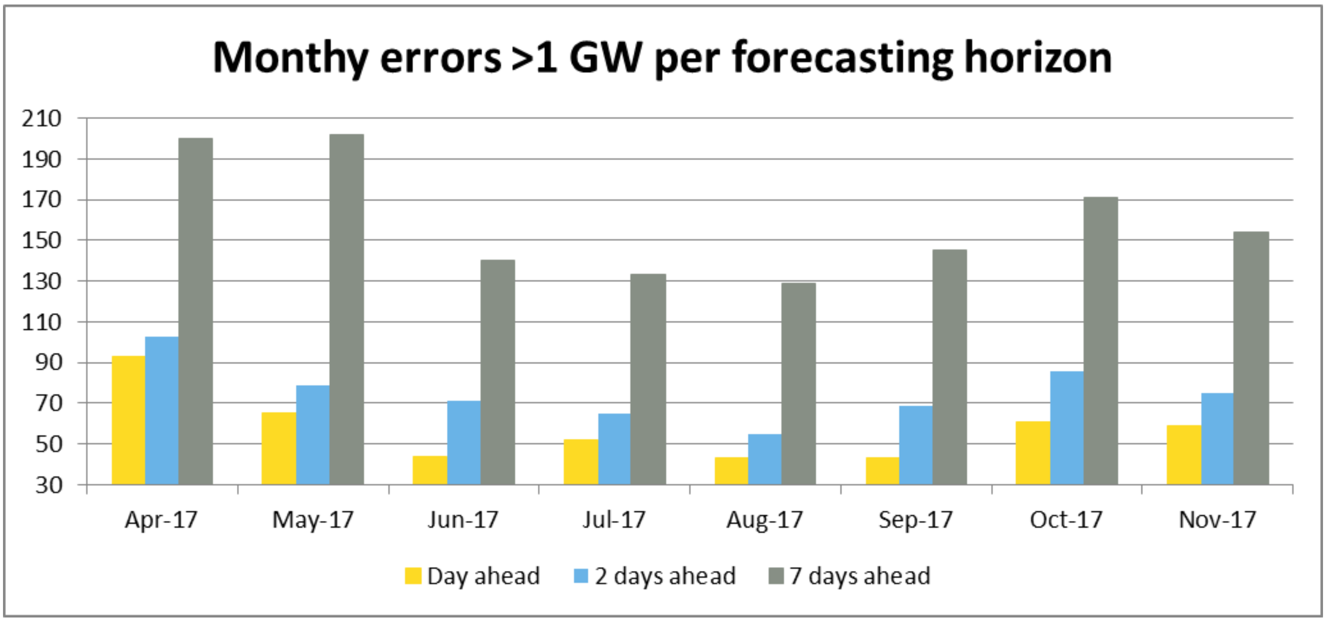
The above 3 graphs show that in Qtr3, it was generally far more challenging to meet the required targets for the overnight CPs (particularly 1S, 1A, 03 & 1B).

The daytime CP's forecast errors (particularly 2A, 2B and 3B) typically improved within Qtr3 at the DA and 2DA lead times.

However, the fact that many of the performance measures show significant errors indicates that it is still difficult to meet the required targets.

MONTHLY COUNT OF LARGE ERRORS (GREATER THAN 1000MW)

The graph below depicts the count of errors above 1000 MW since 1st April 2017. It looks at the incentivised forecast horizons only, i.e. day ahead, 2 days ahead and 7 days head. It should be noted that the data for December is excluded as the reporting period covers only 3 days of the month and hence is not representative.



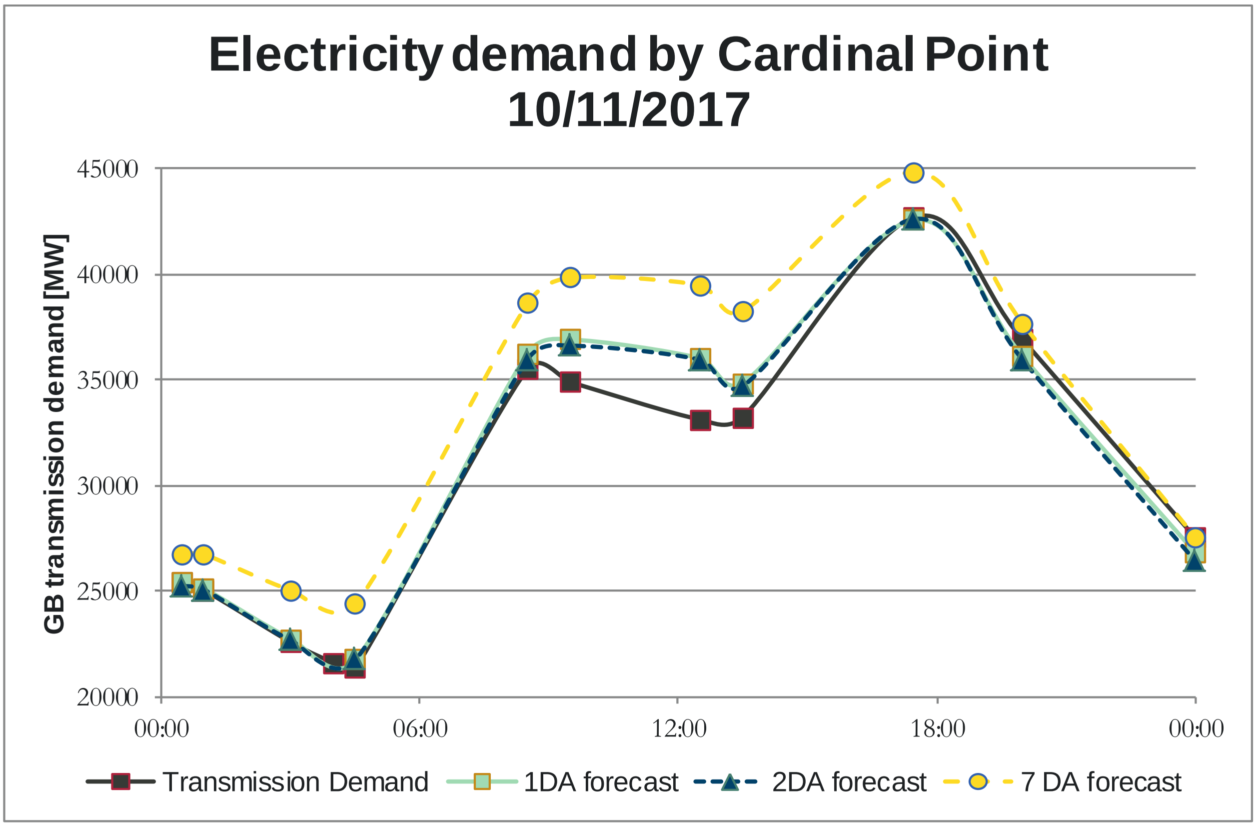
The graph above illustrates that the number of large errors (greater than 1000 MW) increases as lead time increases. It also shows that a number of large errors is significantly lower over the summer months.

CASE STUDY – 10TH NOVEMBER 2017

The forecast for the 10th of November had large errors at every time horizon, and featured in the top 5 forecast errors for each forecast horizon (see Appendix 2)

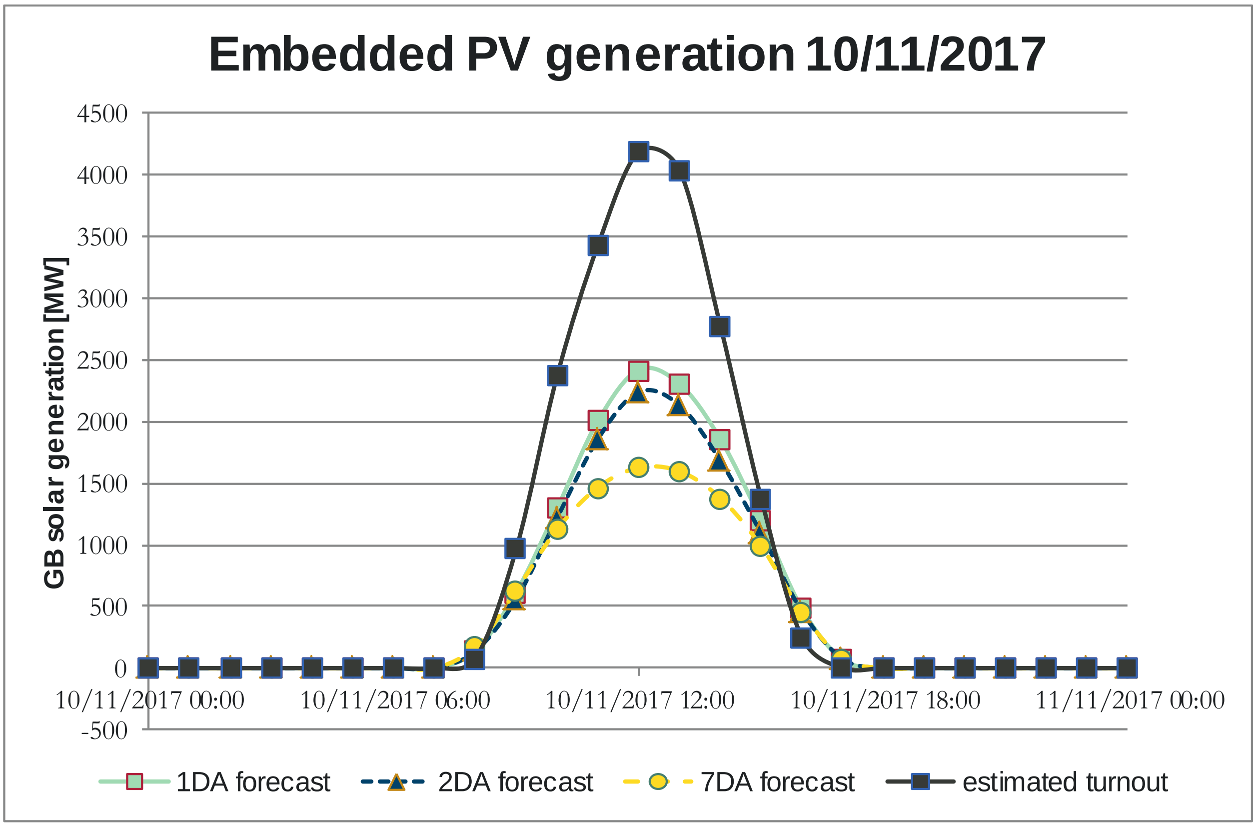
This day experienced near-normal temperatures, slightly higher than normal wind speeds and was brighter than average.

Forecasted and metered national demands for this day are shown in the graph below.



On a 7 day lead time, observed wind speed and temperature higher than forecast, leading to lower turnouts than forecast. At 2 and 1 day lead times the forecasts were in agreement with each other, suggesting relative certainty in the forecast accuracy.

On the day itself, it turned out to be a bright day for the season and much brighter than forecast. Embedded PV generation estimates and forecasts are shown below.



Solar outturns were approx. 2000 MW higher than forecast. Intra-day PV generation forecasts were still suggesting significantly smaller amounts of generation than eventually occurred.

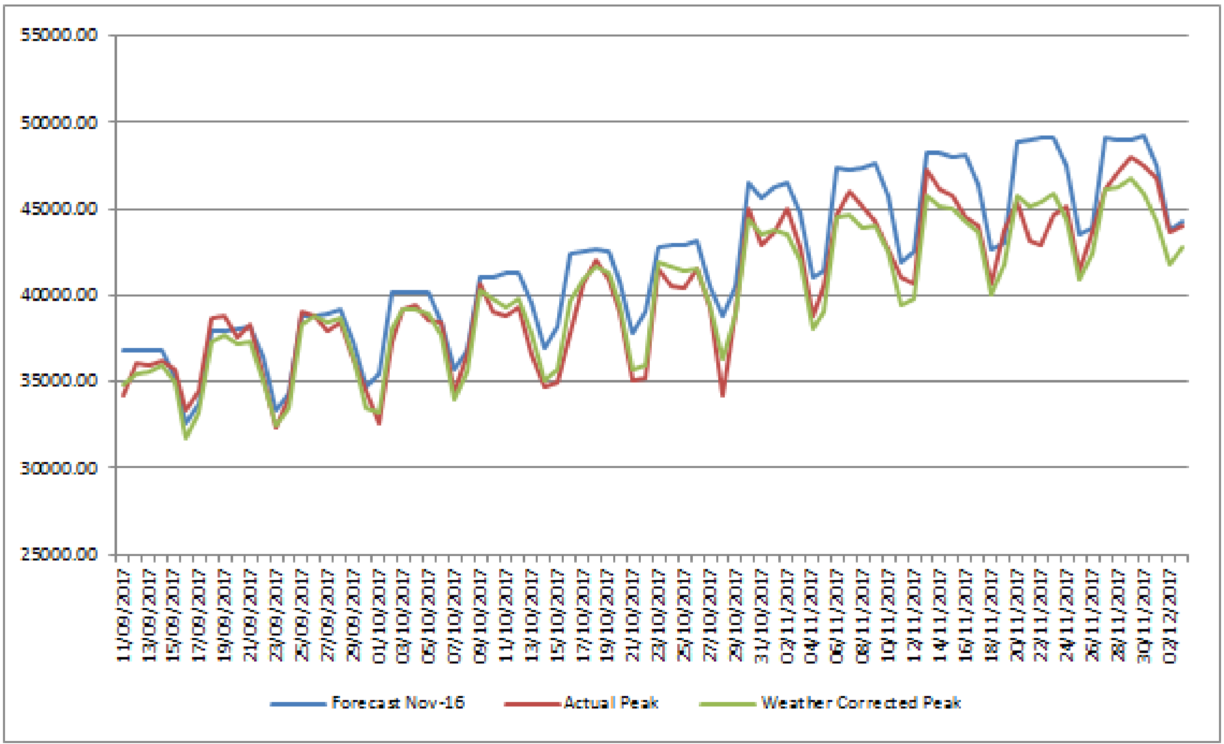
This day illustrates that even at times of the year where the sun radiation is weaker, errors in the PV generation forecasts can still lead to significant demand forecast errors.

One of the contributing factors is the persistence of low clouds in the winter and shoulder seasons. Here, a thin layer of clouds could lead to an overcast day, or, if conditions are right, these can dissipate, resulting in a bright day.

The main source of error can therefore be traced back to model inputs (the meteorological forecast of solar radiation in particular) rather than uncertainty in our models themselves.

2-52 WEEKS AHEAD DEMAND FORECASTS

The graph below shows our 2-52 weeks ahead peak national demand forecast, as published in November 2016 on the BMRS website for the reporting period 11th September – 3rd December 17. This forecast is based on seasonal average weather. The graph also compares our forecast with both actual demand and weather corrected actual demands.

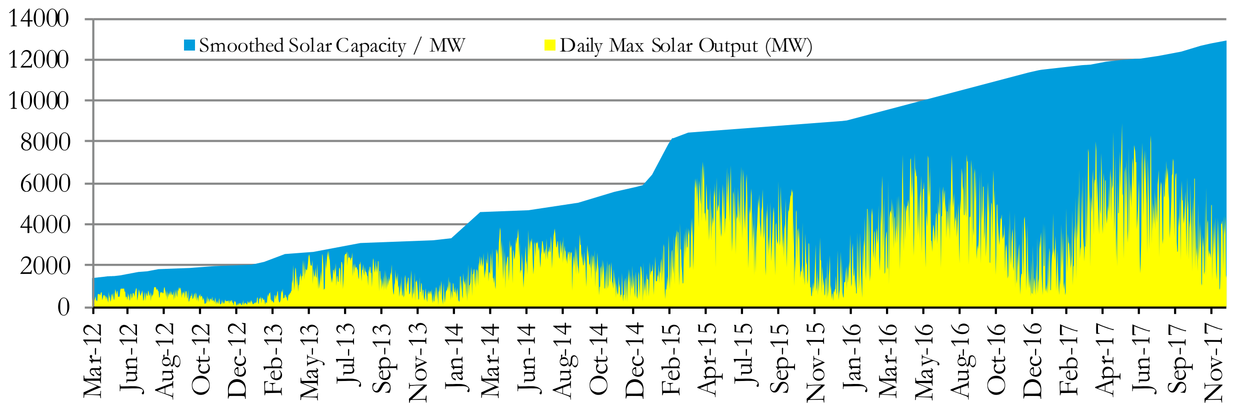


For the reporting period as a whole, the mean absolute error between the 2-52week peak national demand forecast and actual demand was 1.8GW, compared to 1.1GW during the previous quarter.

The maximum error was 6.2GW on the 22nd of November, compared to 3.7GW during the previous quarter. Errors during this period are affected by the fact that long term forecasts do not take into account only real weather forecasts, but also triad avoidance actions, which normally occur during the November to February window. Forecasts are required to be made without taking these actions into account, whilst the outturn does of course reflect such actions if they occur.

EMBEDDED PV

During the previous quarter, solar generation capacity increased from 12.4GW in Sept 17 to 12.9GW in Dec17. The graph below depicts the daily maximum national solar generation output (based on the Sheffield Solar PV live data) and the installed solar generation capacity.



DESCRIPTION OF SOLAR GENERATION AND FORECAST ERRORS

Our solar generation forecasts, as published on BMRS and the Data Explorer section of the National Grid website, arise from an internal PV generation forecasting model, based on a number of parameters:-

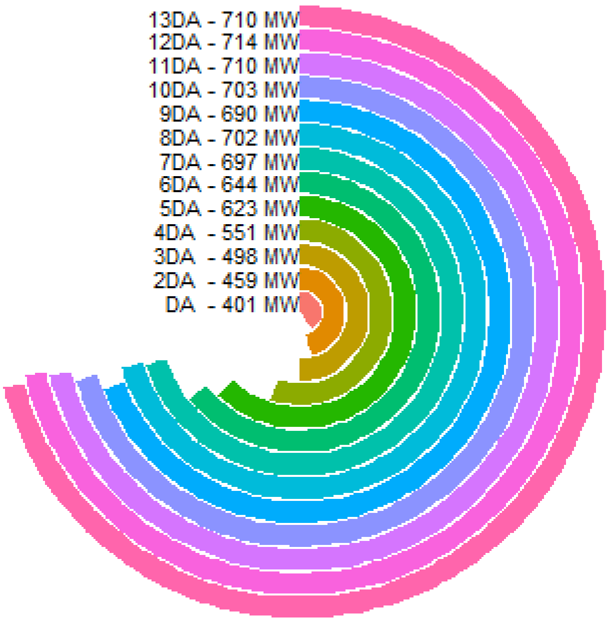
- Estimated capacities,
- Weather forecasts from our weather provider and
- Empirically derived models connecting radiation and national generation, using data from our NIA collaboration with Sheffield Solar.

Our weather forecasts extend from the current day out to 14 days ahead, and so our solar generation forecasts have the same time horizon. Beyond this, we use seasonal normal weather.

The figure below gives an illustration of our mean absolute solar generation forecast error for daylight hours, against lead time of the forecast in days ahead (DA). The error is measured against the national generation estimated from our Sheffield Solar NIA project.

Some further details on the trends are given in the analysis section.

Mean abs PV Error (MW)



It can be observed that our mean absolute PV error has reduced slightly over almost all forecast time horizons from Q2 to Q3 (with an average of 623MW in Q3 compared to 726MW in Q2), although this still remains at a sizeable level. Further discussion of this is given below

ACTIONS AFFECTING SOLAR GENERATION FORECASTS AND ERRORS

During the period 11th Sept – 3rd Dec, a number of actions were taken to optimise the solar generation forecast. As part of our regular PV model reviews, we refreshed the PV generation models twice leading to immediate improvements in mean absolute error. These improvements generally reduce with time until the next refresh.

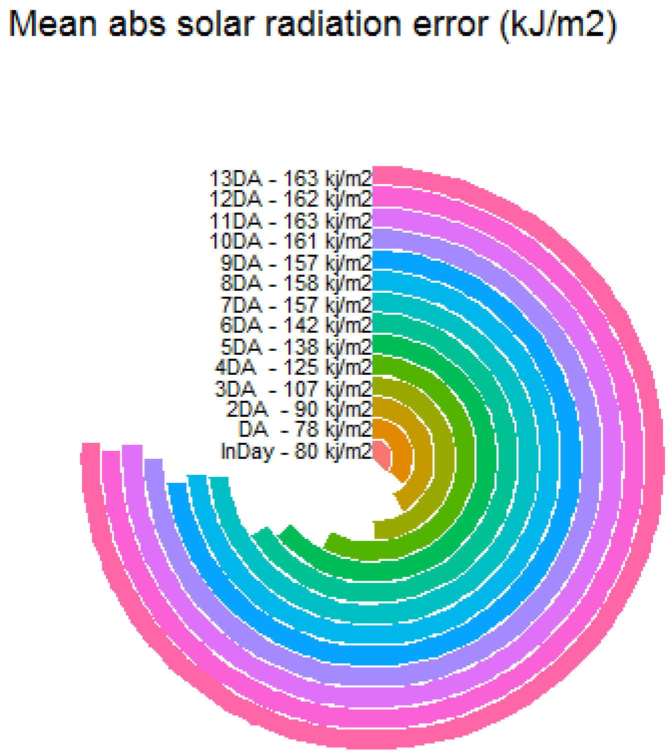
ANALYSIS OF THE CAUSES OF SOLAR GENERATION FORECAST ERRORS & FUTURE ACTIONS

As a number of parameters feed into the forecast of solar generation, errors in each of these contribute to the discrepancy with the actual real generation. However, as error in capacity or outturn can only be estimated theoretically (as there are no standard benchmarks nor solar metering available to National Grid), we take the estimates of capacity and outturn as exact, and break our forecast error down into just two components – *Model Error and Weather Error:-*

Error = *P (weather forecast) – Observed Outturn =*
(P (weather actual) – Observation) + (P (weather forecast) – P (weather actual)) =
Model Error + Weather Error

where P is the function being used to convert weather data into solar generation data.

The radiation forecast is the main weather variable used from our weather forecasts. The figure below illustrates the values of mean absolute radiation forecast error seen during the period 11 th Sept– 3rd Dec. The figure is plotted for daylight hours only



It can be seen that solar radiation forecast errors dropped noticeably between Q2 and Q3, consistent with the seasonal changes. This is also discussed in the 'Weather Analysis' section.

We know from sensitivity analysis of our internal models, that an error of 50kJ/m2 in radiation is equivalent to around a 150MW error in our national PV forecast.

Using this scaling to cross compare the solar radiation error values to those of PV error, shows that solar radiation forecast or weather error is again a significant source behind our overall solar PV forecast error. Our NIA project with our weather forecast provider, which aims to improve the weather forecast in this front-line area of meteorology, is ongoing.

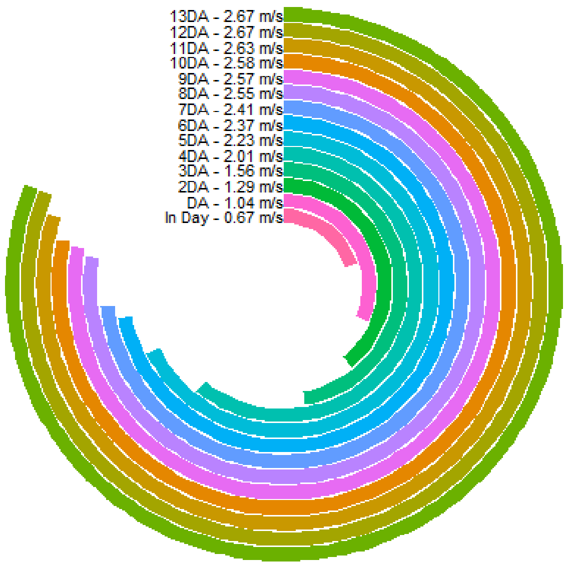
In this particular Quarter however, our solar power errors are such that solar radiation forecast or weather error is not as dominant a driver as in Q2. We have looked at this in more detail, and solar power model error was at least as significant during this time. This seems to have arisen from a long period until the first model refresh, and a shorter impact than previously experienced, likely due to the dynamics of the shoulder period.

During this Quarter, we made a first review of the proposed new solar power model as provided by our Reading University NIA project. We anticipate completing our evaluation and implementation of this in the New Year.

WIND FORECASTS

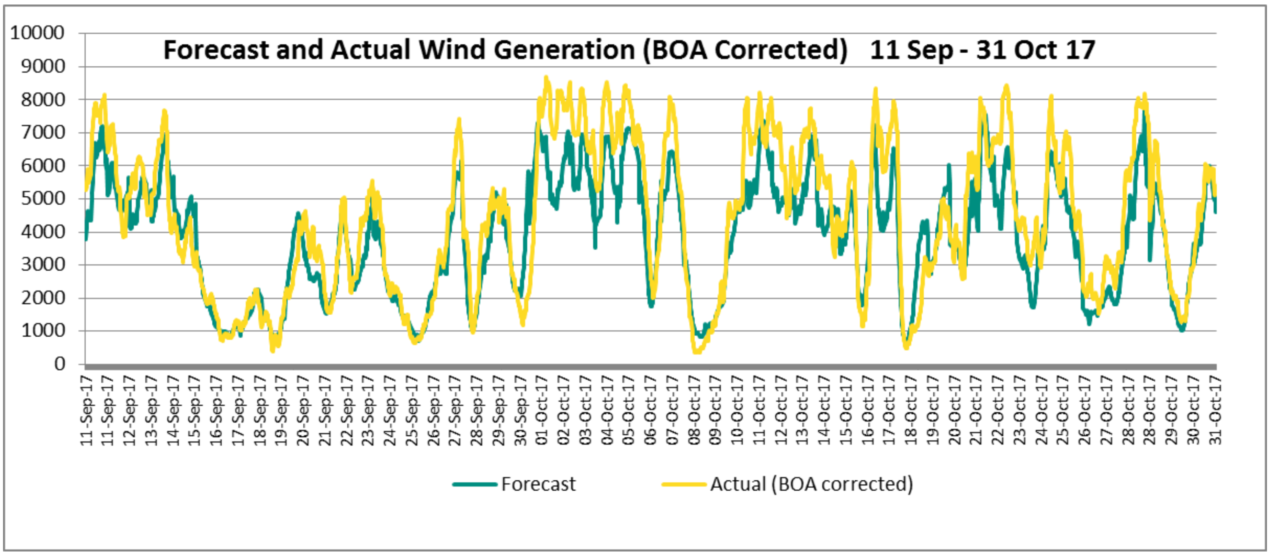
The key input to our forecasts is the wind speed forecast. The graph below shows the mean absolute error in wind speed forecast in m/s at different time horizons. As an indication of the impact of the errors, in the mid part of a wind power curve, between around 5 and 15 m/s, a 1 m/s error in wind speed forecast equates to around a 10% error in wind power forecast for the generator.

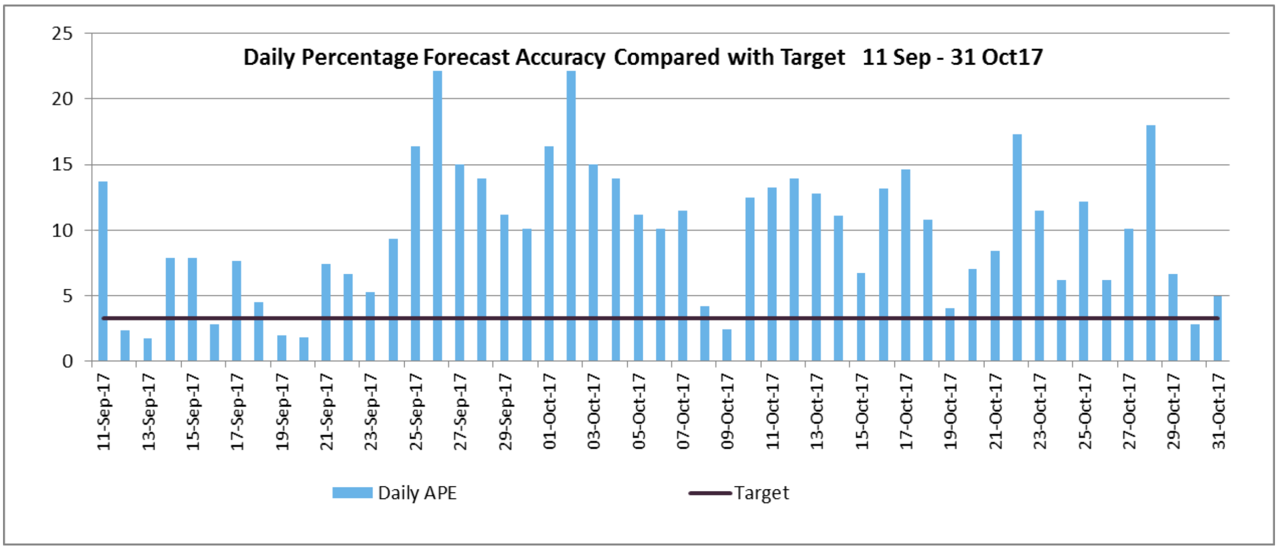
Mean abs wind speed error (m/s)

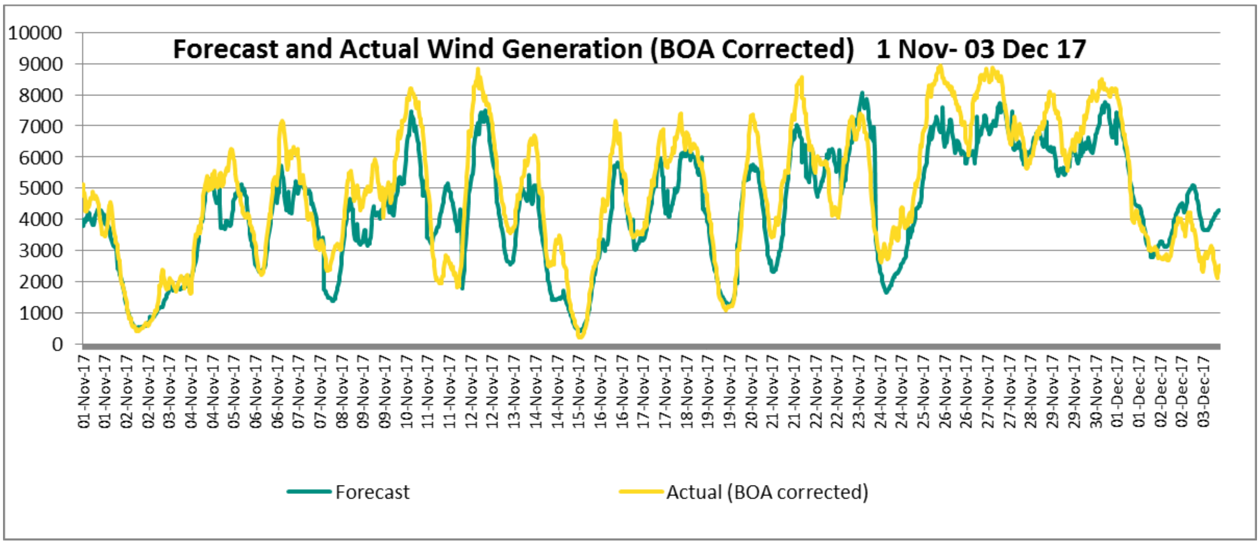


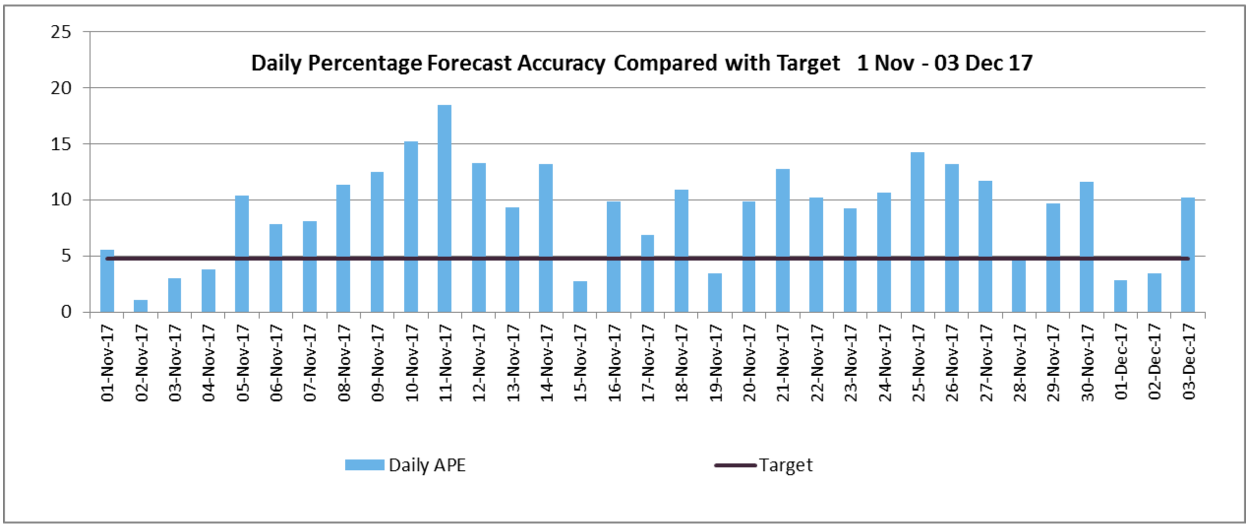
The wind incentive measures our performance in forecasting the wind power that is available, and does not require us to forecast the actual wind output after the control room have taken bid-offer-acceptances (BOAs) on wind farms to manage constraints or other system issues in real time. In order to report this, the forecasts for each individual wind farm for each half hour are recorded. For the half hour where a BOA is taken on that farm, the unit is discounted from the calculation of corrected forecast, corrected outturn and corrected installed capacity. The percentage error for the forecast for that half hour is then calculated from the corrected values, and a daily average is then calculated which is used in the formulae described in the incentive to calculate the outcome for that day.

In terms of performance for Qtr.3, the graphs below show the comparison of corrected forecast and actual wind generation for the period 11th of September until 3rd of December, as well as the daily average percentage error used to calculate the outcome of the incentive.


Forecast and Actual Wind Generation (BOA Corrected) 11 Sep - 31 Oct 17
Forecast
Actual (BOA corrected)


Daily Percentage Forecast Accuracy Compared with Target 11 Sep - 31 Oct17
Daily APE
Target


Forecast and Actual Wind Generation (BOA Corrected) 1 Nov- 03 Dec 17
Forecast
Actual (BOA corrected)



Wind generation forecasting was particularly challenging during this Quarter. Our average forecasting error after BOA's increased significantly compared to the previous three months, in spite of an increased target from October onwards. This resulted in us receiving the maximum incentive penalty for accuracy for the months September to November.

The second component of the wind incentive scheme is the bias incentive. In this component, the objective is to have as many over-forecasts as under-forecasts, with a target of 50:50, a breakeven of 60:40 and a maximum penalty of 70:30.

There is also a separate term in the bias incentive that states that if any two individual forecast half-hours are 70% biased or greater, the maximum penalty is incurred. For the wind incentive, this means if any two out of 48 half hourly forecasts are 70% biased or greater than the maximum penalty is incurred. This equates to 9 out of 31 forecasts in a month being one side of zero and 22 being the other side.

In September, October, and November, the forecasts overall had more than two half-hours outside of the [30%, 70%] bias range, and so we automatically received the maximum bias incentive penalty for each of these 3 months.

WIND GENERATION MODELLING

Efforts to review and improve the power models for larger wind farms are continuing. On the 28th of November we completed a significant update of our wind power models for the transmission connected wind farms. In total we reviewed and updated over 90% of the portfolio (totalling around 150 wind farms in total).

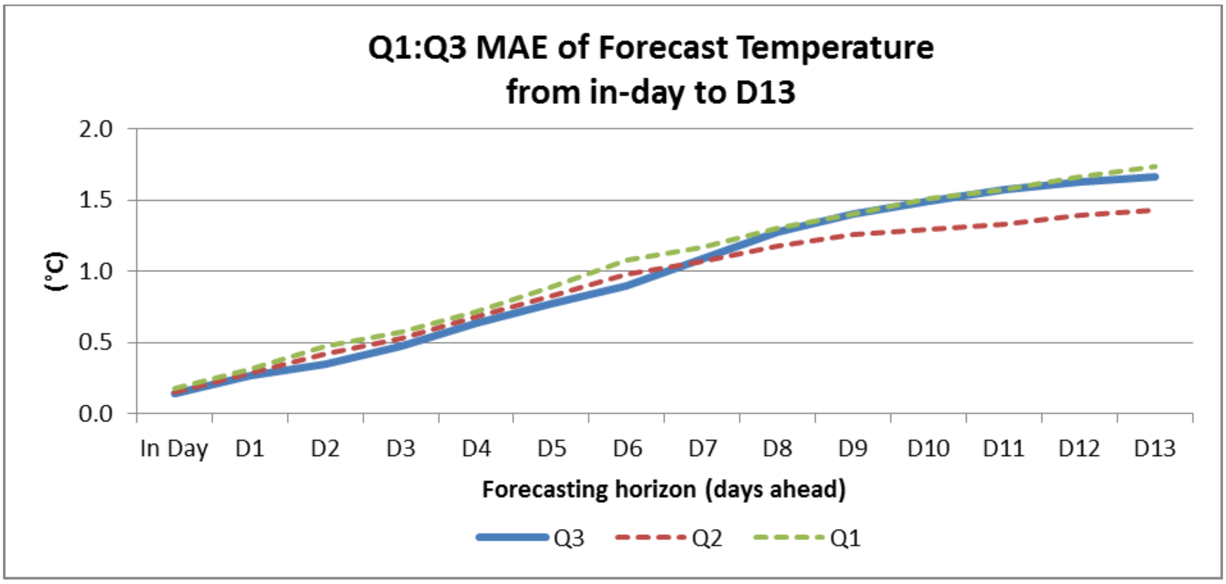
WEATHER ANALYSIS

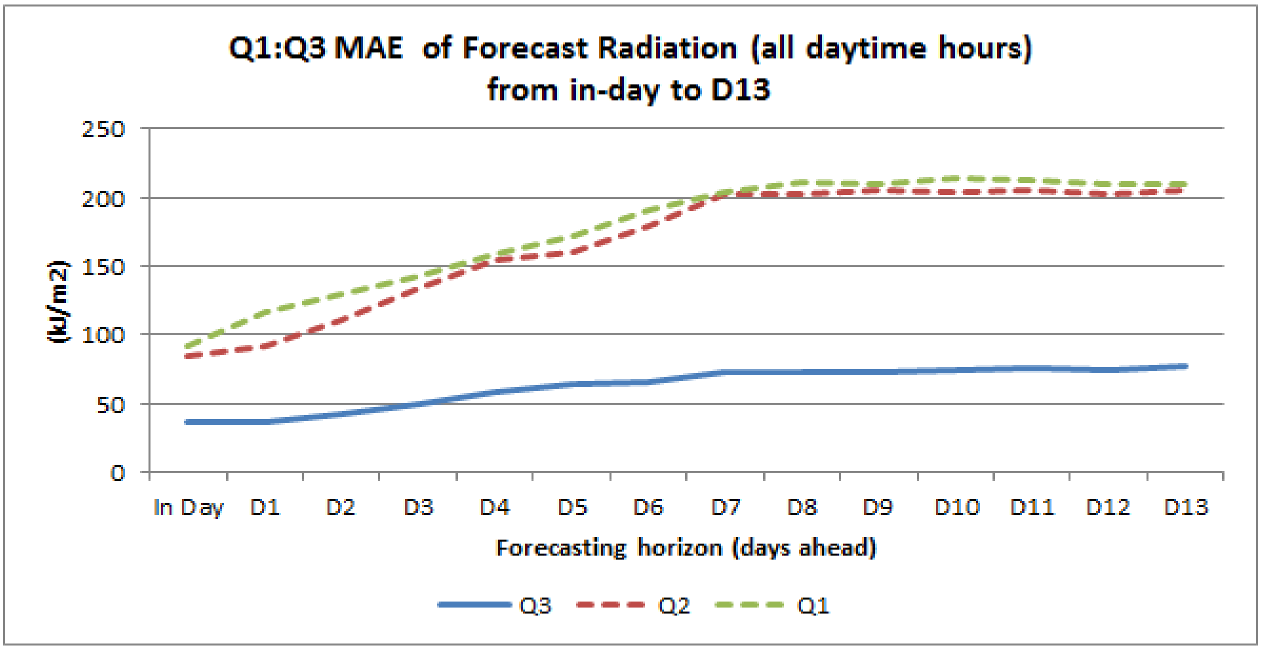
Demand forecasts rely on a number of inputs, chief among them being the forecast weather for selected locations around the country. Errors in forecasted weather lead to errors in the forecast demands and wind- and solar generation. Manual corrections can occasionally be carried out if there is any certainly on expected weather forecast errors.

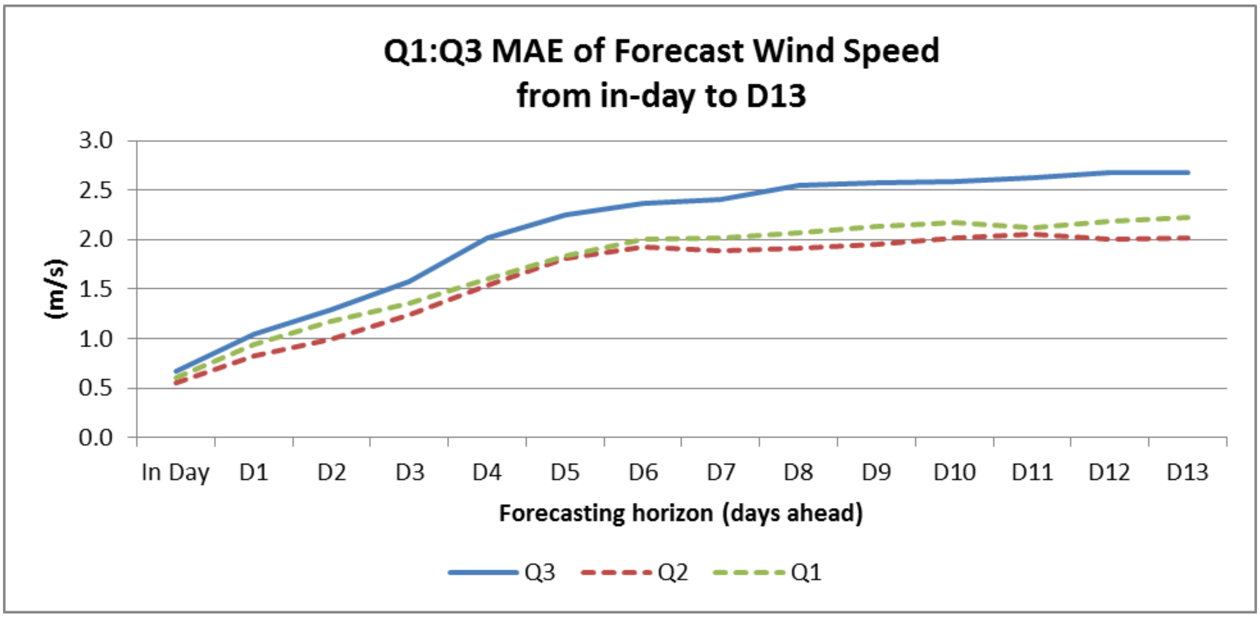
The graphs below show the mean absolute errors in the forecasts that we receive for our key weather parameters over the 0 to 13 day- ahead forecast horizons.

- Temperature is measured in °C, with 1°C approximating to a demand forecast error of ~500 MW.
- Solar radiation is measured in kJ/m^2, with 50 kJ/m^2 approximating to an error of 150 MW in our PV forecasts. Note that the graph below shows MAE calculated across all hours of the day (in contrast to the data in the PV section where only daylight hours MAE is shown)
- Wind speed is measured in m/s, with 1 m/s in the range 5 – 15 m/s corresponding to an error in generation forecast for the wind farm of around 10% of capacity

Each graph shows the mean absolute weather forecast error for this Quarter, as well as a comparison to the same error for the two previous quarters.







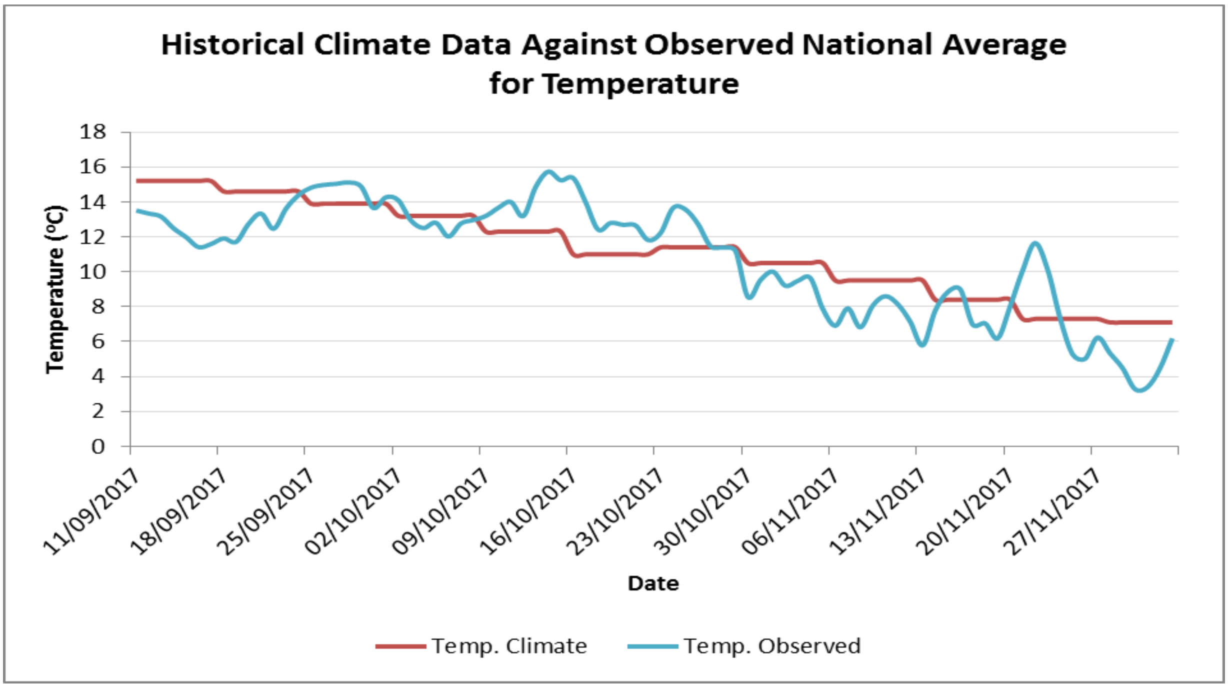
The charts above show that as the forecast lead-time increases, the weather forecast errors become greater. For wind speed and radiation, the errors level off from the 7 days-ahead lead time, as there is little meteorological skill beyond this point. With temperature forecasts, a slight improvement in the Qtr. 3 against the two previous quarters can be seen up to 7DA. However for later forecasting horizons, the error gets progressively worse.

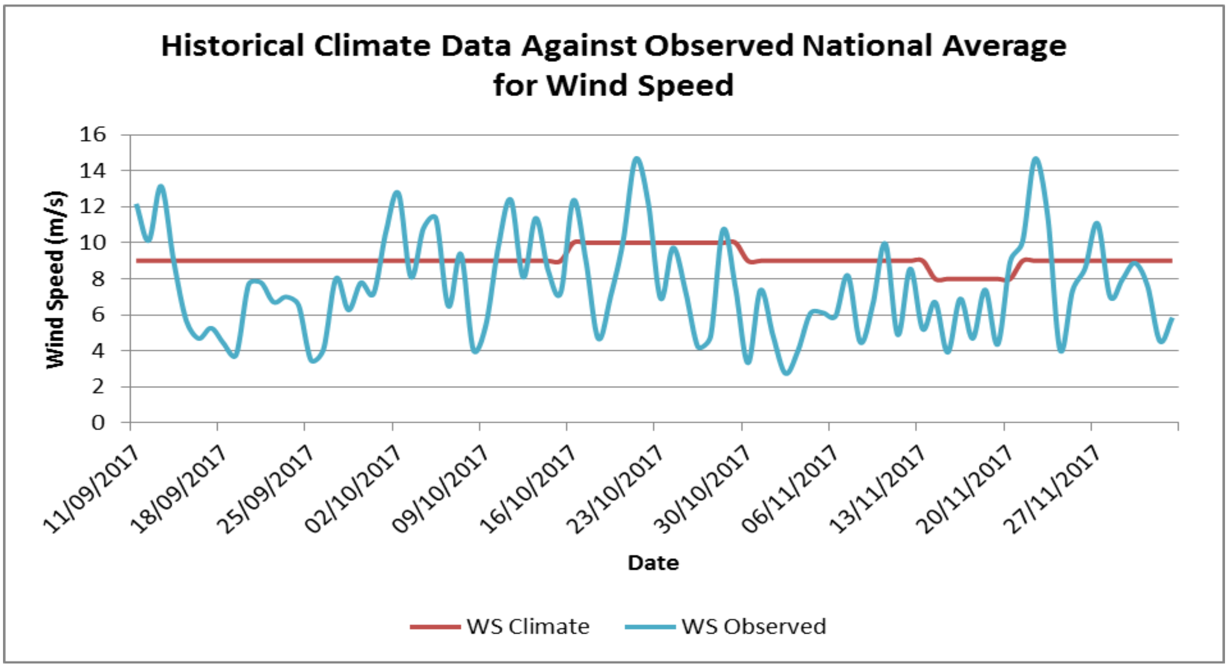
The sizeable improvement in forecast radiation error between the last Quarter and the two previous Quarters is due to seasonal differences. As days become shorter and solar angles change, radiation levels decrease significantly, with tighter bounds between maximum and minimum outturns, and a reduction in absolute errors.

In terms of wind speed, this was slightly higher during Qtr. 3 compared to the two previous quarters. This is consistent with typical seasonal behaviour due to atmospheric conditions.

The core information displayed by the above charts is firstly the significance of forecasting horizon, where a relatively high gradient between In Day and D7 implies an increasing difficulty in accuracy, whereas the maximum chance of error lies between D7 and D13. The magnitude of these errors contributes significantly to the challenges in achieving accurate demand forecasts, as highlighted in detail in the Case Study part of this report.

Secondly, the data shows notable differences in radiation and wind speed between seasons, further increasing the difficulty of demand forecasting. In order to ensure the accuracy is maintained, systems and models (especially PV, wind and national demand) must be updated and reviewed throughout the calendar year to account for these seasonal variations. The following graphs explain this further by showing the variation of temperature and wind speed of the current quarter compared to the mean values over the last 30 years of historical climate data.





Both of the above two charts also show significant variations for observed values when compared to climatic data over the Qtr. 3 reporting period, with wind speed variations being particularly pronounced. This exemplifies the limitations inherent in the production of accurate forecasts on longer timescales, which are by necessity based on seasonal average weather.

WORK TO IMPROVE FORECASTS

Some of our work to improve our forecasting accuracy has been mentioned in earlier sections, but for completion we highlight and collate these activities again here.

- As per our regular demand model updates, we updated our weather & time demand models to account for GMT (winter) behaviour.
- The internal PV generation forecast model has been updated twice, once in October and again more recently in November, both of which led to immediate accuracy improvements.
- We made a first review of the proposed solar power model as provided by the Reading University NIA, and we anticipate completing our evaluation and implementation of this now in the New Year.
- On November 28th, we completed a significant update of our wind power models for the transmission connected wind farms. In total we reviewed over 90% of the portfolio (totalling around 150 wind farms in total).
- Work is continuing to build upon the work completed with our external partners and NIA projects, as well as our strategic review of the Energy Forecasting system.

CONCLUSIONS

A detailed analysis is presented describing the errors and sources of errors in National Grid's demand, solar and wind generation forecasts for the period 11th September 2017 to 3rd December 2017. In addition, the work that has been done to improve these forecasts is described.

Some highlights during this reporting period were a peak demand of 47.3GW on 13th November 2017, and an overnight minimum of 17.1GW on the 2nd of October 2017.

The overnight minimum demand was the lowest ever observed for the month of October. The previous October record low was 19.3 GW in 2016.This is a significant drop and due particularly to the contribution from embedded wind as well as mild overnight temperatures.

Daytime cardinal point errors tended to improve slightly at the day ahead and two days ahead forecast horizons. For the overnight cardinal point demand forecasts, errors generally worsened during this Quarter..

The number of large demand forecast errors, greater than 1GW, increased slightly, consistent with expectations from the seasonal change.

Our embedded PV generation forecast errors remained higher than desired, in spite of notably reduced solar radiation forecast errors. This seemed to be connected to our solar power model refreshes, something which we anticipate focussing more closely on in the New Year.

Finally, wind generation forecasting was challenging during this Quarter. Our average forecasting error after BOA's increased compared to the previous three months. At the end of November however we completed a significant update to the majority of our transmission connected wind power forecasting models, which should help manage the error from December.

Work continues on our internal projects and with our NIA-funded projects to improve our forecasting accuracies further.

APPENDIX 1 – SOURCES OF DEMAND FORECAST ERROR

Forecast error is made up of many independent, but interacting components. On some days small errors due to several different components can result in a large overall error, while on other days two very large errors can cancel out leaving a net very accurate forecast.

The components of error are:

- Model error - errors in demand model coefficients. Coefficients are estimated from data..
- Residual in demand forecast models, which represents the variation in underlying demand unexplained by model.
- Short term demand fluctuations (1 day to 1 week) unexplained by the model. Estimated by the forecasters' choice of basic demand.
- Error in outturn demand – demand data received by NG differs from "real" outturn demand because of metering errors, data transfers errors. In addition outturn demand is calculated on an assumption that the frequency is a constant 50 Hz. As frequency deviates from this figure the actual demand differs from the calculated demand. We can estimate that this introduces an error of up to ± 100 MW in the outturn demand.
- Error in weather forecast data – difference between forecast and actual observed weather at weather stations can be measured, and our models can be used to retrospectively estimate the impact of these errors on our demand forecasts
- Error in wind and PV capacity – our embedded wind and solar models assume a certain capacity, and its geographical location. National Grid has limited data on such installations, and data has to be gathered from publically available data sources. This data is neither exhaustive nor up to date.
- Error in solar radiation weather forecasts – the solar radiation forecasts are a key input to our forecasts for PV generation, and can be a significant source of errors.
- Error in PV models – we use models to convert forecast solar radiation into forecast PV load factors. The models use radiation forecast at a single point to represent solar radiation incident on a very large area on which PV installations are installed. We currently use 53 solar radiation measuring stations across GB, so on average each measuring point represents an area of 8840 km^2. The error can be estimated by comparing model output with model estimates of outturn PV generation, as discussed next.
- Error in outturn PV – NG in collaboration with the Sheffield Solar team of Sheffield University produces an estimate of outturn PV generation. It is based on a limited sampling from a number of installations combined with complex algorithms. There is an approximately 10% error in this estimate of PV generation. Error in wind speed weather forecasts – we currently receive wind speed forecasts for around 100 locations in the country. Some of these are weather station locations where observations are available, allowing us to quantify the error at these locations, but other forecasts are for sites near large wind farms where outturn data may not be available. We can however estimate the error from the points that we can measure.
- Error in embedded wind generation models – we use models to convert the nearest available wind speed forecast into a generation forecast for embedded wind farms. As per embedded PV, there is no available output data available to National Grid. Error cannot be quantified. We assume these errors are broadly comparable to the errors in metered wind farm forecast.

APPENDIX 2 – BREAKDOWN OF LARGE INDIVIDUAL ERRORS

DAY AHEAD FORECASTING ERRORS

Date	CP	Forecast	Actual	Error	Forecaster Note
17th Sep 17	3B	24400	26906	-2506	A sunny autumn day. Estimated PV turnout at 14:00 was 1405 MW higher than forecast.
25th Oct 17	3B	33200	30007	3193	A bright and mild day. Estimated PV turnout at 14:00 was 2575 MW higher than forecast.
29th Oct 17	1S	21560	19206	2354	Half hour before clock change, uncertain demand shape due to extra hour and clock change behaviour.
10th Nov 17	2B	36020	33117	2903	An unexpectedly bright day. Estimated PV turnout at 12:00 was 1770 MW higher than forecast.
29th Nov 17	DP	48910	46452	2458	High demand day, estimated 1600MW of demand suppression for Triad avoidance

2 DAY AHEAD FORECASTING ERRORS

Date	CP	Forecast	Actual	Error	Forecaster Note
25th Oct 17	3B	33910	30007	3903	A bright and mild day. Estimated PV outturn at 14:00 was 2920 MW higher than forecast.
10th Nov 17	2B	35950	33117	2833	An unexpectedly bright day. Estimated PV outturn at 12:00 was 1950 MW higher than forecast.
11th Nov 17	1B 2F 2B	20650 30220 31850	23534 33412 34761	-2884 -3192 -2911	This day was forecast to be windy, but turned out to experience only moderate winds. Wind speed errors were: -4 m s^{-1} at 05:00 -6 m s^{-1} at 09:00 -5 m s^{-1} at 11:00 Furthermore, this day experienced a sudden and unexpected jump in underlying demand. (See appendix 1, point 2 and 3)

7 DAY AHEAD FORECASTING ERRORS

Date	CP	Forecast	Actual	Error	Forecaster Note
5th Oct 17	3B	32790	28115	4675	An unseasonal mild and bright day. Estimated PV forecast error 3150 MW Nationally averaged wind speeds were 12 $m\ s^{-1}$ compared to a forecast of 9 $m\ s^{-1}$
21st Nov 17	4B	40640	36217	4423	A very mild November evening. Temperature outturn nationally was 10.9°C @ 21:00hrs (4B) compared to forecast 6.1°C. Wind speed was 13 $m\ s^{-1}$ compared to a forecasted wind speed of 7 $m\ s^{-1}$
10th Nov 17	2A 2B 3B	39830 39480 38250	34882 33117 33248	4948 6363 5002	This was a windier, warmer and particularly brighter day than forecasted. Estimated PV turnout was 336 MW higher than forecasted at 09:00 2565 MW higher than forecasted at 12:00 1400 MW higher than forecasted at 14:00 National temperatures were 1.5 - 2°C higher than forecast and wind speeds were 3 - 5 $m\ s^{-1}$ higher than forecast.