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A Quantitative Assessment of the Variability of Wind

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Abstract

Using real, historic half-hourly wind generation data for an existing portfolio of wind projects across financial year 2012/13, the frequency and magnitude of error measures derived from a variety of persistence forecast bases and their associated costs at imbalance versus market value were assessed against expected values and against individual performance indicators such as capacity factor, various values of capacity credit (as derived from different accepted definitions) and seasonal/time-of-day fractional generation output, highlighting key relationships. Total contracted value increases with total volume and capacity factor. Net imbalance value negatively correlates with capacity factor. Average contracted value is not dependent upon the total volume generated, but rather the time at which it is generated. The average net income is beneficiary of the above stated relationships - error magnitude and frequency are key suppressors of average net income and output delivery time and total volume key inflators of net income.

Objectives

1. **To extract a valuable data sample:** complete, consistent, reliable and up-to-date in-house and market domain data, representative of and relevant to the company's existing wind generation project portfolio.
2. **To analyse the wind project sample:** comparison of basic wind power performance measures such as capacity factor and appropriate definitions of capacity credit.
3. **To quantify the variability of the power output:** comparison of common error measures (MAE, RSME, SDE, NMAE, NRSME & RSDE) derived from the analysis of persistence forecast bases
4. **To value the variability at system imbalance:** system-relevant market rates applied as payments and charges, eliciting average (£/MWh) values and costs.
5. **To consider the effect of season/time-of day:** output in industry 'peak'/'off-peak' and 'winter'/'summer' periods assessed in relative to average values and costs.

Methods

Data for any wind generation projects which did not meet the assigned criteria across financial year 2012/13 were excluded from the sample. A further provision was included to separate, where necessary, those projects whose wind generation are subject to self-supply (demand) variations. Market domain data sets were also collated for the matching same period. The selection of **capacity credit** considered alongside **capacity factors** included Milborrow's loss of load expectation (LOLE) basis [1] and the IET's loss of load probability (LOLP) basis [2]. From observed HH generation levels, $O_t(\tau)$, persistence forecasts, $F_t(\tau)$, at time, t, were created for a variety of time bases, τ;

$$E_t(\tau) = O_t(\tau) - F_t(\tau)$$

Error measures for each project were then derived and normalised against each project's capacity and compared across forecast time bases and scale of project. Also assessed were HH UK total wind generation, HH UK max. incidental total gross system demand, demand net of wind and the demand net of a derived higher penetration HH UK wind profile. For each HH, associated **values and costs of errors** were calculated (as at imbalance) from the perspective of the BSC party; **contracted value** from HH UKPX market value prices, **imbalance value** from the published HH index value (assigned by overall system and BSC party positions), HH **net income value** from the sum of previous values, and averages across the financial year as a function of the sum totals and the total generated volume (£ per MWh basis).

BSC Party Position	System Position	
	Short	Long
Short	Pay Market (SBP)	Pay Reverse (UKPX)
Long	Paid Reverse (UKPX)	Paid Market (SSP)

Table 1: Assigned HH Index Value

Season/time-of-day was considered using averages for HH demand and HH UK total wind generation, market value (UKPX) price data for each HH of the day and for each month of the year. Averages were then taken for industry **seasons** (summer as Apr-Sep, winter as Oct-Mar) and for the industry **time-of-day** periods (peak as 7am-7pm Mon-Fri, off-peak as remaining times of day & days of week). For comparison, percentage of wind generation of each wind project during these periods was also calculated. In order to identify and understand any key relationships, an assessment of all derived and natural parameters was completed within an identified **subset of similar wind projects** (4 x single turbine - Enercon E48/800).

Results

24 projects were deemed suitable for comparison, 10 of which incorporated self-supply. Capacity factors ranged from 21.5-38.2%, UK total wind 29.03% (expected 30% [1.]). Capacity credit values varied with method, proving inconsistent. Error measures increased with forecast time basis, with long-term average output generally more accurate than 18+ hour persistence forecasts, and decreased with project scale – UK total wind NSDE was 1.2% (expected ≤3% [1.]). Errors from UK total wind variability were largely absorbed by the scale of demand variability (<1% increase in SDE), and for a simulated future wind penetration level of 20% residual demand SDE increased by <5%, MAE by <9%. When considering value the lower errors encountered in the aggregated wind portfolio resulted in total net imbalance savings of 37.4% (-£382k from -£609k) in in FY 12/13, an average of only -1.97%.

As can be seen in **Table 2,** right, total contracted value (14) is consistent with total volume (17) and capacity factor (4). Net imbalance value (15) negatively correlates with capacity factor (4). Total net income (16), being derived from these figures, exhibits the same relationships. Lower average contracted values were generally consistent with lower winter output (22) and lower peak output (24), highlighting the importance of time at which power is generated. Higher capacity factor (4) gives a higher level of generation year-round which leads to a higher frequency of low value forecast errors (in summer output (25) and/or off-peak output (27) periods), reducing the average net imbalance value (20). Average net income (23) is beneficiary of the complex relationships described above; error magnitude and frequency both acting as apparent key suppressors of average net income and generation output delivery time and total volume both acting as apparent key inflators.

Parameter	Project	1	2	3	4
1	Group	A	A	A	A
2	Turbine Manufacturer/Model no.	Enercon E48/800	Enercon E48/800	Enercon E48/800	Enercon E48/800
3	Capacity (kW)	800	800	800	800
4	CC Basis 1 (=CF)	32.62%	26.87%	23.30%	27.62%
5	CC Basis 2	41.08%	39.11%	34.11%	39.21%
6	CC Basis 3	27.25%	22.44%	19.46%	23.07%
7	Forecast Basis, τ (min.)	60	60	60	60
8	$MAE_\tau(T)$ (kW)	33.60	30.47	28.09	31.90
9	$RMSE_\tau(T)$ (kW)	55.20	51.03	49.94	52.45
10	$SDE_\tau(T)$ (kW)	55.20	51.03	49.94	52.45
11	$NMAE_\tau(T)$	4.20%	3.81%	3.51%	3.99%
12	$NRMSE_\tau(T)$	6.90%	6.38%	6.24%	6.56%
13	$NSDE_\tau(T)$	6.90%	6.38%	6.24%	6.56%
14	Total Contracted Value	£106,515.10	£88,726.95	£76,206.57	£91,063.34
15	Net Imbalance Value	-£4,494.45	-£3,997.59	-£3,563.81	-£4,264.60
16	Total Net Income	£102,020.65	£84,729.36	£72,642.76	£86,798.75
17	Total Volume (MWh)	2,286.21	1,882.72	1,632.81	1,935.38
18	Average Contracted Value (/MWh)	£46.59	£47.13	£46.67	£47.05
19	Average Net Imbalance (/MWh)	-£1.97	-£2.12	-£2.18	-£2.20
20	Average Net Imbalance (/MWh)	-4.22%	-4.51%	-4.68%	-4.68%
21	Average Net Income (/MWh)	£44.62	£45.00	£44.49	£44.85
22	Winter Output	56.97%	62.87%	62.70%	61.86%
23	Summer Output	43.03%	37.13%	37.30%	38.14%
24	Peak Output	37.87%	39.39%	37.97%	39.51%
25	Off-Peak Output	62.13%	60.61%	62.03%	60.49%

Table 2: Assessment of results across similar projects

Conclusions

The error values associated with UK demand net of wind profiles showed relatively low increases in absolute error values, implying that the system largely absorbs most of the error currently associated with wind variability, and would be able to absorb increased errors en route to 20% wind penetration. Portfolio aggregate wind was subject to significantly lower imbalance costs, with the UK aggregated profile benefiting further, implying support for arguments for aggregated wind generation management. As demonstrated across a group of similar projects, correlations exist between forecast error frequency, magnitude and season/time-of-day output fractions; as we progress down a path of continued investment in wind power technology, a more detailed understanding of these relationships, attributes and dynamics will become more pertinent.

References

1. Milborrow, D., 2009. Managing Variability, s.l.: s.n.
2. IET, 2007. Wind Power - A Factfile provided by The Institute of Engineering Technology, London: The IET.