wind-up uplift validation methodology

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The wind-up tool measures energy yield uplift and uncertainty of wind turbines after they are changed in some way such as a turbine upgrade or implementation of wind farm control. The wind-up methodology uses best practice from the turbine power performance standard IEC61400-12-1 and adds innovative steps to achieve additional goals such as measurement of uplift under all conditions (including waked operation).

The wind-up tool can use met mast data and LiDAR data to measure uplift of upgraded *test turbines* as would be the case in a IEC61400-12-1 power performance test. However, this document focuses on the case where mast and LiDAR data is not available. In that case non-upgraded turbines are used as *reference turbines* to measure the uplift of upgraded *test turbines*.

The wind-up methodology comprises the following steps:

1. Identify any changes to the wind farm or in the vicinity of the wind farm that would change the relative performance of turbines in comparative analysis. Examples could include neighbouring wind farm construction, tree felling or other upgrades outside the scope of the upgrade under test. Any such changes need to be evaluated and potentially would mean certain turbines or time periods need to be excluded from data analysis.

2. A set of *reference turbines* is chosen for each test turbine. At least three reference turbines are used where possible. The following factors are considered when selecting reference turbines:

   i. Turbines for which the active power correlates most strongly with the test turbine are favoured as reference turbines. Normally these are also the closest turbines to the test turbine.
   ii. Turbines for which the mean wind speed is similar to the test turbine are favoured.
   iii. A reference turbine must have no known performance issues and should not have undergone any significant changes itself during the test period
   iv. It helps where possible for a reference turbine to be un-waked in the predominant wind direction, especially by the test turbine itself

3. Historic SCADA data (typically 10-minute but other timebases e.g. 1-minute can be used) for all turbines on the wind farm are used to derive normal operational curves of power, pitch angle and generator rpm. Filters are applied to flag as invalid any data that is far outside of this normal behaviour. Data records are also flagged as invalid if a turbine is offline for any of the period. The only valid data remaining is for turbines that are online and operating without curtailment.

   Some wind farms will have significant periods of curtailment where turbines are operating at reduced power due to environmental or grid-related factors. This might affect the uplift achieved by the upgrade. In this case it will normally be necessary to conduct a separate analysis using only curtailed periods and then combine this with the un-curtailed estimate to produce an overall result. If only certain turbines are significantly curtailed then at least one of these turbines would need to be tested and the overall wind farm uplift calculated by combining turbine results accordingly.

4. The dataset is divided into two periods: *before* and *after* the upgrade. For a toggle test these two periods are the *toggle off* and *toggle on* data, respectively. For a non-toggle test, the *after* period

will start when the upgrade installation is complete and will normally run until the day when the analysis is conducted to use as much data as possible.

A principle of *seasonal matching* is used, such that the *before* period is chosen to use the same months as the *after* period, but in the previous year. The aim is to reduce seasonal bias in the analysis. For a toggle test this is ensured by applying a toggle pairing filter which only keeps data where the time difference between a data record and the nearest valid record with the opposite toggle state is within expected limits.

It is important that neither of the periods include any other known changes or upgrades to either the test or reference turbines. This is ensured by a combination of removing reference turbines that exhibit changes (as described in steps 1 and 2 above) and shortening the data periods as required, whilst still maintaining the seasonal matching approach.

5. The validation methodology is based on a *wind speed estimate* at the test turbine location that is derived using data from the reference turbine in each data record. To derive this estimate first a robust wind speed estimate is first calculated for the reference turbine. This is a combination of the anemometer-measured wind speed on the reference turbine nacelle and the turbine's active power, as follows:

    i. For low wind speeds close to and below turbine cut-in, and for high wind speeds close to and above rated power, the wind speed signal is used (with any corrections applied eg anemometer bias or air density)

    ii. For intermediate wind speeds (i.e. in the cubic region of the power curve, sometimes called *region 2*) the active power is used and is mapped to an equivalent wind speed based on the average turbine power curve

    iii. For the transition regions the two signals are blended to create a smooth transition between using wind speed and power. The precise approach used for this transition is modified for each turbine model based on the observed power curve.

    This approach produces the most robust signal to use for the subsequent analysis. Active power is a better predictor of test turbine power than the anemometer wind speed so is used in region 2, but it becomes less useful near cut-in and rated power, hence the switch to using the measured wind speed instead.

    This approach relies on the assumption that the anemometer of the reference turbine produces consistent measurements across the test period (both before and after the upgrade). If significant changes to the reference anemometer calibration are expected or observed, the power signal would instead be used for the full range. However, this reduces the amount of useful data at high and low wind speeds.

6. The wind speed estimate at the reference turbine is now converted into a wind speed estimate at the test turbine. The relative wind speeds at the test and reference turbines will vary with direction because of terrain and wake effects. The wake effects will themselves depend on which upwind

turbines are operational at any particular time. To account for this and reduce noise in the analysis, a process of *directional normalisation* is undertaken as follows:

i. A historic period of SCADA data is used, starting from just before the upgrade was applied to the test turbine and extending back 3 years (or as far as possible if 3 years of data is not available). For toggle tests, data periods measured during the toggle test when the upgrade was *off* may also be included. Together this forms the *normalisation data*.

ii. The nacelle direction from all turbines is analysed to detect any shifts in northing calibration for the full normalisation data period, which are then corrected.

iii. The normalisation data are filtered to include only wind speeds in the range 4 - 16m/s and then analysed to determine all the combinations of operational turbines that exist in the data. For example, if all turbines are operational and un-curtailed apart from turbine T1, this represents one possible combination. Another combination is all turbines operating together.

iv. Only combinations that have at least one day's worth of data in the normalisation data are retained.

The remaining steps happen for each retained combination of operational turbines in turn:

v. For each data record a *wind speed estimate* is calculated for both the reference and test turbines separately using the methodology described in step 5.

vi. Using the reference turbine's yaw direction as a proxy for wind direction, for each one-degree wind direction bin, data from up to 5 degrees either side is selected from the normalisation data. The mean test wind speed estimate in each of these 10-degree windows is divided by the mean reference wind speed estimate in each window, resulting in 360 calculated ratios.

vii. The wind speed estimate calculated for the reference turbine in each data record is multiplied by the directional correction ratio to produce a directionally-normalised estimate of the wind speed at the test location. This is the estimate of the wind speed seen by the test turbine based on a combination of power and wind speed measurements at the reference turbine. It accounts for both directional trends and for upstream turbines being offline. This concept is called ***ws_est*** (short for estimated wind speed) for the remainder of this methodology.

7. The data are divided into bins based on *ws_est*. A bin width of 1m/s is used by default, although this may be increased to as high as 2m/s if there is insufficient data. Any bins which have below the minimum required amount of data are excluded. This minimum is defined as 3 hours of data per 1m/s of wind speed bin width. Excluded bins are considered to have zero uplift in the final calculation.

8. The mean power produced by the test turbine in each bin is calculated for both the *before* and *after* periods. A correction is then applied to this mean power to account for the fact that the mean value of *ws_est* will not be exactly at the centre of each bin, using a linear interpolation approach:

$$mean\_test\_power_{corrected} = mean\_test\_power + test\_power\_corr$$

where:

$$test\_power\_corr = \left(ws\_est_{bin\_centre} - ws\_est_{bin\_mean}\right) * \left(\frac{test\_power\_delta}{mean\_ws\_delta}\right)$$

and where *test_power_delta* and *mean_ws_delta* are the differences in *mean_test_power* and mean wind speed between the two bins either side of the bin in question.

9. To calculate the Annual Energy Production (AEP) for the test turbine based on the *before* and *after* data, the binned mean powers must be combined with a long-term distribution of test turbine *ws_est*. This long-term distribution is derived using 5 years of historic SCADA data.

   The estimate of the uplift produced by the upgrade according to the particular reference turbine being used is then calculated as follows:

$$AEP\ Uplift = \frac{AEP_{after}}{AEP_{before}} - 1$$

10. The AEP uplift result is modified using the concept of *reversibility*. If there were no biases present in the analysis, it should be possible to reverse the test and reference turbines in our methodology and produce a result that is exactly the inverse of the original result, arriving at a second (equal) estimate of the test turbine uplift. However, in reality these two results are rarely equal due to noise and comparing the two can reveal hidden bias in the original analysis.
    The full calculation cannot simply be reversed because this would involve using the test turbine anemometer wind speed, which might have been impacted by the upgrade. Instead, both the original and reverse calculation are performed using *power data* only (removing the use of the anemometer) and the difference between these results is used to correct the AEP uplift estimate as follows:

$$Corrected\ Uplift = Uplift_{original} - \frac{Uplift_{power\ only} - Reversed\ Uplift_{power\ only}}{2}$$

11. The above process is repeated for each reference/test combination, to produce a number of different uplift estimates per test turbine. The process is also repeated using each reference turbine as a test turbine, with the expectation that 0% uplift is measured for each reference turbine. The purpose of this step is to detect any possible bias in any of the reference turbines, by seeing whether any of them have a measurable change in performance relative to the others, and/or whether they tend to consistently predict changes in the remaining reference turbines. Based on this analysis it is determined whether any of the reference turbines should be excluded from the subsequent combined uplift calculation.

12. The uncertainty of each reference/test pair uplift estimate is calculated as the maximum of three uncertainty components:

    i. The first component is the statistical uncertainty based purely on the spread of data in each wind speed bin. This is sometimes referred to as the Category A uncertainty and follows the approach of IEC61400-12-1 [1]. Bins that were excluded based on low data count are given zero uncertainty at this stage and accounted for later (see step 13). The per-bin uncertainties are then combined assuming independence between each wind speed bin to give an uncertainty on the total AEP and on the AEP uplift.

    ii. The second component is based on a *block bootstrapping* approach, in which large time series blocks of the test period are removed at random and replaced with another block, after which the AEP uplift is recalculated. Repeating this many times produces a distribution of AEP uplifts, from which the confidence interval can be calculated and used as an estimate of the uncertainty in the original AEP estimate.

    iii. The final component is based on the principle of *reversibility* in the methodology as described above. If the original and reversed uplift estimates are significantly different this suggests an error in the analysis. Both uplift estimates are derived using power data only and the uncertainty component is calculated as follows:

$$Reversibility\ Error = \frac{Uplift_{power\ only} - Reversed\ Uplift_{power\ only}}{2}$$

    The combined uncertainty is calculated as the maximum of these three components. It is then adjusted as per the following step.

13. The final uncertainty for a test/reference pair is now adjusted to account for the fact that some wind speed bins are missing due to the data count limits. The combined uncertainty is multiplied by a factor that depends on the proportion of long-term energy produced in the missing bins:

$$Uncertainty\ Scale\ Factor = \frac{1}{\left(1 - \frac{AEP\ in\ Excluded\ Bins}{Total\ AEP}\right)}$$

    In most uplift measurement situations it is reasonable to assume zero impact above rated power. In these cases only bins below rated power are included in the calculation of the uncertainty scale factor.

14. The final AEP uplift estimate for each test turbine is calculated by combining the individual reference turbine estimates for all remaining reference turbines using an uncertainty-weighted approach, where the weighting is proportional to the inverse of the squared uncertainty. This is a standard approach to combining uncertain estimates.

The uncertainty of this combined AEP uplift for each test turbine is calculated by combining the following three uncertainty components:

i. The combined uncertainty assuming full independence between reference turbine uplift estimates:

$$\sigma_{independent} = \sqrt{\sum_{1}^{n} (\sigma_n w_n)^2}$$

where the normalised weights w_n are calculated as follows:

$$w_n = \frac{1/{\sigma_n}^2}{\sum_1^m 1/{\sigma_m}^2}$$

ii. The combined uncertainty assuming full correlation between reference turbine estimates. This is the weighted mean of the uncertainties, weighted by the inverse-square of the uncertainties themselves. This will always be higher than $\sigma_{independent}$ and simplifies to the following expression for *n* reference turbines:

$$\sigma_{correlated} = \frac{\sum_1^n \frac{1}{\sigma_n}}{\sum_1^n \frac{1}{{\sigma_n}^2}}$$

The two components above are averaged to produce a first estimate of the uncertainty for this test turbine:

$$\sigma_{test} = \frac{\sigma_{independent} + \sigma_{correlated}}{2}$$

iii. The final component is intended to account for possible bias in the reference turbines. Each reference turbine has its own combined AEP uplift estimate based on running it as a test turbine against other reference turbines, which we would expect to be close to zero. The weighted absolute average of this uplift estimate across all remaining reference turbines is used as a lower limit on the final test turbine uncertainty:

$$\sigma_{ref} = \frac{\sum_1^m |U_m| w_m}{\sum_1^m w_m}$$

where U_m is the AEP uplift estimate of the m^{th} reference turbine based on running it as a test turbine against the other reference turbines, and w_m is the weighting given to the m^{th} reference turbine based on the inverse-square of σ_{test} for this turbine:

$$w_m = \left(\frac{1}{\sigma_{test}^m}\right)^2$$

The final combined uncertainty for a particular test turbine is then calculated as follows:

$$\sigma_{AEP} = max(\sigma_{test}, \sigma_{ref})$$

15. The above steps produce an estimate of the AEP uplift and uncertainty for each test turbine. The methodology now extrapolates this uplift to the wind farm as a whole by repeating steps 9 to 14 using the wind farm average *ws_est* distribution in place of the turbine-specific distribution. This produces an estimate of the whole wind farm uplift that would be achieved by the upgrade based on a single test turbine. If there are curtailment schemes in place on particular turbines that would affect their AEP uplift then this is accounted for in this step.

16. If multiple test turbines have been used, the final combined AEP uplift estimate is calculated as an uncertainty-weighted mean across all test turbines, using the values of σ_{AEP} for the wind farm derived using each test turbine in step 15. The uncertainty on this combined AEP uplift is calculated assuming partial independence across test turbine estimates by using the same approach as outlined in step 14 above for the calculation of σ_{test}:

$$\sigma_{combined} = \frac{\sigma_{independent} + \sigma_{correlated}}{2}$$

where $\sigma_{independent}$ and $\sigma_{correlated}$ are calculated in the same way as described in step 14 but combining across test turbines rather than reference turbines.

References

[1] Wind energy generation systems - Part 12-1: Power performance measurements of electricity producing wind turbines (IEC 61400-12-1:2022). International Electrotechnical Commission, September 2022.

Revision History

Issue	Date	Name	Latest changes
01	2024-09-04	Alex Clerc	First Created
02	2024-10-16	Alex Clerc	Formatting improvements
03	2025-01-21	Alex Clerc	Added new step (step 1) and References section