1 Abstract

This paper describes the development of a relatively simple new parameterization of wind turbine induced drag forces for use in today’s state-of-the-art mesoscale (“high resolution”) numerical weather prediction models. The parameterization is developed for the typical situation where several of the wind turbines of a large wind farm are contained within one vertical column of model grid boxes of the atmospheric model, but in the vertical, several model layers intersect the rotor area. The entire wind farm may span over several adjacent model grid columns.

This parameterization can be used to simulate the feedback of the additional drag forces caused by large wind farms on the atmospheric background flow (e.g., wake region, mean flow within wind farms). First results of an idealized simulation study using the Weather Research and Forecast Model (WRF) are shown in the paper. After further refinement and tuning, this model system might also become a feasible tool for offshore wind energy forecasting.

Keywords: wind turbine drag, parameterization, mesoscale model, mean flow within wind farms, wake region, feedback to background flow, power output forecasting.

2 Introduction

Today’s wind turbines for wind power generation are very efficient in transforming the kinetic energy flow $P_{\text{atmo}}$ through their rotor area into electrical power. As a rule of thumb, about 40 - 50% of this flow is "harvested". In turn, this energy amount is lost to the atmospheric flow, causing a significant deceleration in the vicinity of the wind turbine, (e.g., downstream wake flow), as investigated in many studies, e.g., by means of simple analytical models (e.g., [1, 2]) or by wind farm wake models as used in [3] or by very detailed and very costly numerical CFD simulations (e.g., [4]). Nowadays, it is planned to install collections of many wind turbines distributed over large areas, e.g., offshore wind farms in the North Sea.

From the above, it is immediately clear that such huge wind farms are an important sink of kinetic energy within the planetary boundary layer (PBL) and may have to be considered in atmospheric flow modeling, like numerical weather prediction (NWP). On the other hand, the atmospheric flow modification might also have implications for the wind power generation itself. For example, the increased roughness might, aside from the wind speed reduction in the vicinity of the farm, lead to changes of the wind direction within the boundary layer, caused by changes in the balance of inertia, friction and Coriolis force. Loosely speaking, a very large wind farm may ultimately be able to affect the track of a cyclonic storm, at least in its details.

To investigate such feedbacks of wind farms to the ambient flow, today’s detailed high resolution NWP-Models seem to be an adequate tool, with their typical horizontal grid spacings of 1 - 5 km and typical vertical layer spacing on the order of 10 - 50 m within the planetary boundary layer (PBL), along with suitable parameterizations of atmospheric turbulence.

The purpose of this paper is therefore to develop a simple and efficient new parameterization of wind turbine induced drag forces for these NWP models, which could be also used for a more accurate prediction of wind statistics. The use of this parameterization together with an NWP model is viewed as an efficient way of incorporating the bulk feedback of wind farms on the atmospheric flow.

It is planned for the future to generalize the parameterization to allow also for detailed simulations of the wake- and gap-flows in between neighboring turbines, a task which is currently usually performed either by (heuristic) wake flow models or by stand-alone CFD codes in LES mode, without back-coupling to the atmospheric flow. Such simulations are very useful to determine/project/forecast the power output of wind farms. Because the newest generation of NWP models often allows for LES simulations with grid spacings down to 10 m or so, providing at the same time nesting options and back-coupling to the larger-scale flow, these models would be ideal tools for detailed wind farm power output projections, using such a generalized parameterization of turbine drag.

3 Simple parameterization of wind turbine drag

The parameterization for the specific momentum tendencies for the horizontal wind components is developed from the power output curve $P$ from wind turbines, which is tabulated for each wind turbine type as a function of $v_{rh}$, the wind speed at rotor hub height. It is common practice to relate $P$ to a “typical” kinetic energy flow through the rotor area by

$$P(v_{rh}) = C_p \frac{\rho_0}{2} v_{rh}^3 \frac{\pi}{4} d_r^2$$

thereby defining the total efficiency coefficient $C_p$, in the usual way. $\rho_0$ is taken as a reference air density,
usually \( \rho_0 = 1.225 \text{ kg m}^{-3} \), \( d_r \) represents the diameter of the wind turbine rotor. Note that the above “typical” kinetic energy flow might not represent the “true” kinetic energy flow in the presence of a nonlinear vertical wind profile. Also note that \( P(v_{rh}) \) is determined by measurements over longer times and implicitly may contain local “specialities” of the wind profile at the measuring site.

\[ C_p \text{ can be split up into an aerodynamic part } C_a \text{ (efficiency of harvesting the kinetic energy flow through the rotor area) and the loss factor } \eta_{elmech} \text{ due to mechanical friction within the wind turbine and electrical losses caused by, e.g., } \text{current converters. The resulting } C_p = C_a \eta_{elmech}. C_a \text{ depends on the aerodynamic properties of the rotor blades as well as on how if the turning velocity is regulated depending on wind speed by, e.g., angle of attack variations.} \]

If we assume that the turning velocity regulation is solely a function of wind speed, the power output is given by, e.g., angle of attack variations. If it is further assumed that only the horizontal wind component \( v_h (v_h^2 = u^2 + w^2) \) is affected by wind turbine drag and identifying \( v_h \) by its model grid point values (box averages),

\[ \dot{E}_{\text{kin,grid}} \approx \int \int \left( \sum_{k=1}^{N_k} \frac{\partial}{\partial t} \left( \rho_k v_h^2 \right) (z_{k+1} - z_k) \right) dy dx \]

\[ \approx \int \int \left( \sum_{k=1}^{N_k} \rho_k v_h \frac{\partial v_h}{\partial t} (z_{k+1} - z_k) \right) dy dx \] \hspace{1cm} \text{(5)}

\( \rho_k \text{ and } v_h \) represent the average air density and horizontal wind component within grid box \( k \) (grid point values), assuming time constant \( \rho_k \) within the grid box, which is an approximation.

As a reasonable simplification we assume that only the height layers, which intersect with the rotor area, are affected by wind turbine drag forces, so that, expanding the horizontal integrals,

\[ \dot{E}_{\text{kin,grid}} \approx \left( \sum_{k=1}^{N_k} \rho_k v_h (z_{k+1} - z_k) \right) \Delta x \Delta y . \] \hspace{1cm} \text{(6)}

The right hand side of Eq. (3) can be formulated similarly by defining the horizontal areal density function of wind turbines \( f(x, y) \) (local number of wind turbines per area). \( f(x, y) \) is assumed to be constant within a model grid box, so that it can be written as \( f_{ij} \), \( i \) and \( j \) being the horizontal model indices of the grid box. The total number of wind turbines over a larger area is obtained by horizontal aeriel integration. With this, the right hand side of Eq. (3) becomes

\[ \dot{E}_{\text{kin}} \left|_{wp} \approx - \int \int \left( \rho v_h (z_{k+1} - z_k) \right) \Delta x \Delta y \right) \left( \int \int \frac{\partial}{\partial t} \left( \rho v_h^2 \right) dA \right) dy dx \]

\[ = - \int \int \frac{\partial}{\partial t} \left( \sum_{k=1}^{N_k} \rho_k v_h \left( z_{k+1} - z_k \right) \right) \Delta x \Delta y \int \int \rho v_h^2 dA \] \hspace{1cm} \text{(7)}
where \( v_{rh}^{(ij)} \) represents the windspeed at rotor height within grid box \( ij \). \( A_R \) is the rotor area with radius \( R \) (see Fig. 1), assumed perpendicular to the wind direction. In that way, \( C_a \) is assumed constant throughout the rotor area, which is a further approximation. Again, if \( v_h \) is replaced by its model grid point value \( v_{hk} \) assumed constant within grid box \( k \), then this is

\[
\dot{E}_{kin}[w_p] \approx -g_{ij} \left[ 2 \rho_{u-1} v_{k-u-1}^h I(z_{rh} - R, z_u) + \sum_{k=u}^{o-1} \left( \rho_k v_{hk}^3 I(z_k, z_{k+1}) \right) \right. \\
\left. + 2 \rho_o v_{ho}^h I(z_o, z_{rh} + R) \right] .
\]

with the circle segment area integrals \( I(z_a, z_b) \) defined as

\[
I(z_a, z_b) = \int_{z_a}^{z_b} \int_{0}^{\sqrt{R^2 - (z - z_{rh})^2}} \, dx \, dz \\
= \frac{R^2}{2} \left[ \arccos \left( \frac{z_a - z_{rh}}{R} \right) - \arccos \left( \frac{z_b - z_{rh}}{R} \right) \right. \\
\left. + \left( \frac{z_b - z_{rh}}{R} \right) \sqrt{1 - \left( \frac{z_b - z_{rh}}{R} \right)^2} \right. \\
\left. - \left( \frac{z_a - z_{rh}}{R} \right) \sqrt{1 - \left( \frac{z_a - z_{rh}}{R} \right)^2} \right] .
\]

Indices \( u \) and \( o \) denote the lowest and uppermost model height level boundary which is contained within the rotor area (see Fig. 1).

Equating Eq. (8) and (6), i.e., assuming \( \dot{E}_{kin,grid} = \dot{E}_{kin}[w_p] \), and further equalizing the terms for each single height layer on the left- and righthand sides leads to the desired parameterization of the \( v_{hk} \)-tendency for each layer intersected by the rotor area (\( k_u \) to \( k_o \)),

\[
\frac{\partial v_{hk}}{\partial t} \bigg|_{wtdrag} = -C_a(v_{rh}^{(ij)} f_{ij} v_{hk}^3 I(z_k, z_{k+1})) \\
\frac{\partial v_{hk}}{\partial t} \bigg|_{wtdrag} = \frac{u_k}{v_{hk}} \frac{\partial u_k}{\partial t} \bigg|_{wtdrag} \quad \text{and} \quad \frac{\partial v_k}{\partial t} \bigg|_{wtdrag} = \frac{v_k}{v_{hk}} \frac{\partial v_k}{\partial t} \bigg|_{wtdrag} .
\]

which can finally be implemented into a mesoscale atmospheric model.

In this way, the wind power energy production is determined by and reduces exclusively the kinetic energy of the mean (grid scale) flow and induces wind shear. It is then left to the numerical flow model to counteract the local energy- and momentum deficit by shear-generated turbulent diffusion.

In reality, energy is also taken from the subscale turbulent motions, and the wind turbines themselves generate vorticity and turbulent kinetic energy. Moreover, subscale wind flow inhomogeneities caused by gap flows inbetween and wake structures downstream of wind turbines are not resolved in full detail, if the horizontal grid spacing is considerably larger than the
rotor diameter. Such details may however be important for the wind power output of the turbines.

A simple method to approximately take into account at least the effect of subscale kinetic energy production by the wind turbine rotors (which may feed back to the model’s turbulence closure, if the latter is $TKE$-based), is devised in the following. If we define a spatial Hesselberg (density weighted) average,

$$\langle \phi \rangle = \frac{\iiint_V \rho \phi \, dV}{\iiint_V \rho \, dV} = \frac{\iiint_V \rho \phi \, dV}{M_k}$$

(13)

($\phi$ representing $u$, $v$ and $w$) and

$$\bar{\rho} = \frac{\iiint_V \rho \, dV}{V_k}$$

(14)

with $dV = dx \, dy \, dz$, $V_k = \Delta x \Delta y (z_{k+1} - z_k)$ and $M_k = \bar{\rho} V_k$, such that as usual

$$\phi = \bar{\phi} + \phi'' \; , \; \bar{\phi}'' = 0 \; ,$$

(15)

then we can split the kinetic energy in each grid box into a mean and a subgrid scale contribution,

$$E_{kin,k} = \iiint_{\Delta x \Delta y \Delta z} \frac{1}{2} (u^2 + v^2 + w^2) \, dz \, dy \, dx = \left( \bar{u}^2 + \bar{v}^2 + \bar{w}^2 + \frac{\bar{\rho} \bar{\phi}''}{2} \right) \bar{\rho} V_k$$

(16)

The first term on the right hand side is identified as the mean (grid scale) contribution to the kinetic energy ($E_{kin,grid,k}$), and the second term represents the $TKE$ within grid box $k$ ($TKE_k$). We are interested in the local time rate of change of the kinetic energy, and renaming the grid scale quantities with index $k$, this is

$$\frac{\partial}{\partial t} E_{kin,k} = \frac{\partial}{\partial t} \left( \frac{u^2 + v^2 + w^2}{2} \bar{\rho}_k V_k \right) +$$

$$\frac{\partial}{\partial t} \left( \frac{\bar{u}''^2 + \bar{v}''^2 + \bar{w}''^2}{2} \bar{\rho}_k V_k \right)$$

(17)

Note that $TKE$ is defined as per unit mass, which is customary in turbulence modeling, whereas $E_{kin,grid,k}$ is defined per grid box volume, as is the tendendy of the grid scale kinetic energy in Eq. (6).

Eq. (17) motivates to simply parameterize the increase of $TKE$ due to wind turbines as being proportional to the decrease of total kinetic energy due to wind turbines,

$$\bar{\rho}_k V_k \ TKE_k \bigg|_{wp} = -\alpha \ E_{kin,k} \bigg|_{wp} \; ,$$

(18)

so that the gridscale kinetic energy time tendency is larger by the factor $(1 + \alpha)$ compared to the tendency of total kinetic energy removed from the atmosphere by the wind turbines,

$$\dot{E}_{kin,grid,k} = (1 + \alpha) \ \dot{E}_{kin,k} \bigg|_{wp}$$

(19)

$$\dot{E}_{kin,grid} = \sum_{k=u-1}^{o} \dot{E}_{kin,k} \bigg|_{wp} = (1 + \alpha) \ \sum_{k=u-1}^{o} \dot{E}_{kin,k} \bigg|_{wp} \; .$$

(20)

$\alpha$ represents the additional kinetic energy conversion from grid scale to subgrid scale. The such refined wind turbine drag parameterization is obtained by plugging Eq. (6) into the lefthand side and Eq. (7) into the right-hand side of Eq. (20) and again by equating the terms for each single height level. Under the same approximations that led to Eq. (10), the parameterization of wind turbine drag induced $\chi_{khi}$-tendency in each rotor intersecting model height level then becomes

$$\frac{\partial v_{khi}}{\partial t} \bigg|_{wtdrag,k} = - (1 + \alpha) \ \frac{C_a(v_{rhi}^{(ij)}) f_{ij} v_{rhi}^2}{\bar{\rho}_k} I(z_k, z_{k+1}) \; ,$$

(21)

replacing Eq. (10). The corresponding source term for $TKE$, which might be coupled to the $TKE$-budget of the NWP-model (if present), reads

$$TKE_k \bigg|_{wp} = \alpha \ \frac{C_a(v_{rhi}^{(ij)}) f_{ij} v_{rhi}^2}{\bar{\rho}_k} I(z_k, z_{k+1}) \; .$$

(22)

Because of deviations of the apparent wind profile in the model simulation from the underlying mean profile which went into the measured power curve $P(v_{rhi})$ and because of the various approximations drawn to derive the above parameterization, the “true” kinetic energy removal tendency in Eq. (8) (consistent with the parameterized velocity tendency) is not exactly equal to the energy removal tendency given by the power output curve as function of rotor height wind-speed, normalized to the actual air density at rotor height $\rho_{rhi}$, which is

$$\dot{E}_{kin,pc} \bigg|_{wp} = - \frac{P(v_{rhi}) f_{ij} \rho_{rhi} \Delta x \Delta y}{\rho_{0 \text{Helmech}}} \; .$$

(23)

To correct for this, the above tendencies (Equations (8), (10), (21) and (22)) may be further multiplied by the ratio

$$\frac{\dot{E}_{kin,pc} \bigg|_{wp}}{\dot{E}_{kin} \bigg|_{wp}} \bigg( \text{from Eq. (23)} \bigg) = \bigg( \text{from Eq. (8)} \bigg) \; .$$

(24)

The simulated power generation per grid column $P_{sim}$ is then given as

$$P_{sim} = \frac{P(v_{rhi}) f_{ij} \rho_{rhi} \Delta x \Delta y}{\rho_{0 \text{Helmech}}} \; .$$

(25)
Note that the normalization of $\frac{E_{\text{kin},pc}}{P_{\text{sim}}}$ with the air density ratio $\rho_h/\rho_0$ is based on the assumption that $C_p$ is independent of air density and on the fact that the kinetic energy flux is proportional to the air density. $\rho_h$ is regarded as a suitable average value over the rotor area.

Now all that is left is finding an appropriate value for $\alpha$. For the first tests reported in the next section, $\alpha$ has been tentatively set to 0.2. A better estimate of this parameter might in future come from evaluations of more detailed direct numerical simulations of rotor flow, as in [5–7]. However, some limiting values for $\alpha$ can be given. First, $\alpha > 0$ seems reasonable ($TKE$-production by the flow around the rotor blades larger than $TKE$-transfer to the blades). Second, from an energetic standpoint, there cannot be more kinetic energy loss caused by wind turbine power- and $TKE$-production than there is energy flux impinging on the rotor area. Therefore, within the framework of our parameterization, the reasonable limits for $\alpha$ are

$$0 \leq \alpha \leq \frac{1 - C_a}{C_a} = \frac{\eta_{\text{elmech}} - C_p}{C_p}$$

(26)

In case of using a constant value of $\alpha$ in the parameterization (from a physical standpoint it should probably better depend on the windspeed), the maximum allowable $\alpha$ can be computed by using $C_{p,\text{max}}$ from the power output curve of the wind turbines, because $(\eta_{\text{elmech}} - C_p)/C_p$ is a strictly monotonic decreasing function of $C_p$. For example, if $C_{p,\text{max}} = 0.5$ and $\eta_{\text{elmech}} = 0.9$, then $\alpha \leq 0.8$. In light of this, our $\alpha = 0.2$ seems to be a reasonable choice.

If, at a specific location, there is a mix of several types of wind turbines, then simply the tendencies for each type have to be calculated and summed up to the total tendency in each influenced height layer, using the appropriate area density function $f$ for each single type.

Toxday's weather forecasting models typically exhibit horizontal grid spacings in the range of 1-20 km. Typically, within a wind farm, several wind turbines are contained within the footprint area of one such model grid box. Conceptually, the parameterization can be applied down to grid spacings as small as a wind turbine rotor diameter, but not smaller.

As mentioned earlier, in a future version of the parameterization it will be possible to specify smaller horizontal grid spacings by generalizing the circle segment area integral $I$ to allow also the vertical grid faces to intersect with the rotor aera — at the moment only the horizontal grid faces are allowed to do this. With that, LES-Simulations of wind farms with grid distances well below 100 m should be possible, resolving also gap- and wake flows inbetween the wind turbines. However, then the new task arises to implement the generation of subscale $TKE$ and gridscale vortical motion, caused by the spinning rotor blades.

### 4. Idealized simulation for an exemplary large wind farm

The above parameterization of wind turbine induced drag has been implemented into the well-established mesoscale Weather Research and Forecast Model (WRF) version 3.0 from the National Center for Atmospheric Research (NCAR).

To test the parameterization as well as to investigate the influence of a wind farm on atmospheric boundary layer flow speed, a simple yet instructive idealized test case has been set up. An exemplary large wind farm of 225 wind turbines on flat terrain, evenly distributed over an area of $10 \times 10$ km$^2$ ($f = 0.0000025$ m$^{-2}$ within this area, $f = 0$ outside), is centered within a model domain of $61 \times 31$ km$^2$. The horizontal grid spacing is $\Delta x = 1$ km. 80 vertical model levels stretch up to an altitude of 8 km, with level spacing increasing from 16 m at the lower boundary to about 250 m at the model top.

The exemplary power output curve $P(v_{r,t})$ for the wind turbines has been taken from the Multibrid M5000 (nominal power output 5 MW), which has a gear and starts to operate at $v_{r,t} \approx 4.2$ m/s$^{-1}$, has a comparatively high maximum $C_p \approx 0.48$ and $\eta_{\text{elmech}} \approx 0.9$. $z_{rh}$ is 102 m and $\ell$ is 116 m. The shutdown-windspeed is 25 m/s$^{-1}$.

Other specifications are periodic boundary conditions to the North and South, fixed inflow conditions to the West, open boundary conditions to the East on outflow, a Rayleigh damping layer from 5 km height to the model top (damping of vertically propagating gravity waves and their reflection at the upper rigid lid) and the use of a 3-D Smagorinsky-type LES tur-
Horizontal cross section of the wind field at $z = 100$ m AGL after 3 h simulation time. Arrows: $u$ and $v$. Color shades: $u$. Black contour line: $w = 2$ cm/s. The $x$- and $y$ axes are labeled in km.

Bulletin closure as well as surface friction specified by a constant drag coefficient $C_D = 0.0002$.

Horizontally homogeneous vertical profiles of $u$ (no directional shear) and $T$ are specified at model startup, and pressure is initialized hydrostatically, disregarding Coriolis force and geostrophic balance. In this way, the atmospheric flow is kept up solely by its inertia and the constant inflow. The initial $u$-profile follows a power-law formula with exponent 0.1, which is characteristic of very smooth surfaces and rather stable stratification, and is depicted in Fig. 2. The profile characterizes by a strong increase of the windspeed within the lowest 20 m and $u_{r_h} = 10$ m s$^{-1}$ (westerly wind) at the rotor hub height. Temperature decreases linearly with height with a rate of 0.065 K/m (stable stratification).

Note that, because Coriolis force and geostrophic balance are neglected, we cannot expect to see a change of the wind direction with time. This is left to more realistic simulations in the near future.

Horizontal cross sections of the resulting wind field ($u$, $v$ as vectors, $u$ additionally as color shades, $w$ as black contour lines) at $z = 100$ m AGL (rotor center height) after 3 h simulation are shown in Fig. 3 and 4. The color coding in Fig. 3 denotes the $u$-component itself, whereas in Fig. 4, colors denote the difference to a reference simulation without wind turbines. Within the wind farm (dashed line in the domain center) the windspeed is significantly lower than in the surroundings. The effect of the wind turbine induced drag is further highlighted by a vertical West-East-cross section through the center of the model domain of the difference of $u$ to such a control simulation without wind turbine drag in Fig. 5. The wind farm extends from $x$-coordinate 27 km to 37 km with the rotor center height at 102 m. The grid scale windspeed reduction is clearly visible, with a downstream extending wake region. Also, the wind farm acts as a (semi-permeable) flow obstacle and there is a tendency for flow-around and flow-over (not explicitly shown). $u$ is influenced up to a height of about 250 m by the wind farm.

If the vertical temperature- and windspeed stratification is more favorable for gravity waves than this test case is, one might expect the wind farm to generate those waves above and behind the farm. These are present in this simulation but not very pronounced (peak vertical velocities $< 10$ cm/s).

Finally, time series of $u$ at different heights of a vertical column from within the wind farm (solid lines) and from a location well outside the farm (dashed lines) are presented in Fig. 6. Within the farm, at height levels intersecting with the rotor area (black, red and blue), the windspeed reduction after about 30 min stabilizes at about 20 – 25 % compared to undisturbed outside locations, and even about 150 m above the upper rotor tips there is a slight windspeed reduction.

As mentioned earlier, the new parameterization acts solely on the grid-scale (1 km) flow motion and cannot resolve the actual complex windfield at each single wind turbine. However, we assume that the parameterized wind reduction is correct for larger wind farms in an average sense and might be already useful to determine the bulk feedback of wind farms on the impinging atmospheric flow. A generalization to allow for horizontal grid spacings smaller than the rotor area is envisioned.
**Figure 4:** Same as Fig. 3, but the color shades denote $u - u_{ref}$ (difference to reference model run without wind turbines).

**Figure 5:** $x-z$-cross section through the center of the wind farm of the difference of $u$ to a control simulation without wind turbine drag, after 3 h simulation time. Axis units are in km. On the $x$-axis, the label "0" corresponds to 20 km and "30" to 50 km. The wind farm boundaries are at 27 km ("7") and 37 km ("17").
Figure 6: Time series of \( u \) at selected grid points (see legend, coordinates are in km). The solid curves represent gridpoints with horizontal positions within the wind farm, the dashed curves are from points well outside the wind farm to represent the more or less undisturbed flow. The black, red and blue curves are from height levels intersecting the rotor area, the green curve is from above the wind turbines.

5 Discussion and conclusions

A simple parameterization has been developed, which enables to simulate the feedback of wind power generation to the atmospheric flow in the framework of a state-of-the-art NWP-model (e.g., WRF).

The presented first idealized case study shows the reduction effect of a wind farm on the grid-scale wind speed (in this case, reduction of up to 20 - 25 % within the wind farm and a notable influence well beyond the farm area and wind turbine height). These are promising results with respect to the determination of wind statistics from NWP models. However, the question remains, how the average wind speed within a farm correlates with the "apparent" windspeed at each single wind turbine, important for the total power output of the farm. The latter is mainly determined by gap- and wake flows and the turbine position in relation to other turbines and the wind direction and which can be larger or smaller than the grid-scale value of the NWP model. Commonly, computationally very expensive CFD-methods are employed to simulate such flow features, but these lack the feedback to the impinging flow.

Our next step will be to determine the magnitude of the bulk influence of large wind farms on the impinging atmospheric flow by means of real-case simulations in NWP-mode.

For now, the horizontal grid spacing has to be equal or larger than the rotor diameter, so that wind turbines are "subscale" flow obstacles. As mentioned earlier, in a future version it is envisioned to generalize the simple parameterization in a way to allow horizontal grid spacings to be smaller than the rotor diameter, which would enable us to conduct LES-simulations with the WRF model which resolve wake- and gap flows within the wind farm.

References


