Impact assessment of using wind power

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Abstract

This paper discusses a methodology to accurately determine the impact of using wind-energy-conversion systems, WECS, on the operation of the central power system. To do so, the power-generation-simulation code PROMIX is used to simulate the operation of the power system on an hourly basis and on a power-plant level, including the technological restrictions of every plant. The actual impact assessment of the WECS is done by comparing the output of two scenarios; a base case and an alternative scenario which includes the WECS.

To demonstrate the method, several case studies for WECS in different locations in Belgium are worked out. The impact is quantified by looking at the greenhouse-gas-emission reductions that can be obtained by using WECS. In these case studies, we closely look at the influence of the variability of the WECS power output, the geographical spread of the wind farms, the capacity factor and the capacity credit of the WECS and the effect of the power-generation mix.

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0. INTRODUCTION

Wind power is an intermittent, fluctuating, partly unpredictable and non-dispatchable power source. For the conventional part of the power system, wind power can be interpreted — apart from the actual power input— as an increased uncertainty in power deliverability by introducing an additional need for reserve to cope with the power fluctuations.

This paper deals with the implementation of wind-power generation in broader power-generation models. We pay special attention to a detailed analysis of both the power generation of wind-energy conversion and the operation of the central power system.

1. WIND POWER IN POWER-GENERATION MODELS

1.1 Simulation approaches

There are two main approaches that are commonly used for the simulation of wind power in broader power-generation models.

A first approach scrupulously simulates wind-energy-conversion systems (WECS) as a fluctuating power source. The power-output profile of the WECS can be based on actual measurements or on simulated plausible profiles. The simulation of the operation of the rest of the system in cooperation with the WECS is often performed by using a “negative-load” approach. This means that the fluctuating power generation from the wind turbines is interpreted as generation that no longer needs to be provided by the “conventional” part of the power system. In practice, this is achieved by mathematically subtracting the power-generation profile of the wind turbines from the overall demand. In doing so, the fluctuating nature of wind power and the adjusted optimal use of the power system are fully accounted for. This approach is only useful when using a detailed power-simulation tool in which the nuances of the wind-power fluctuations are compatible with the resolution of the model. An example of such a model is PROMIX (Voorspools and D'haeseleer, 2000) in which the operation of a power system, subject to an hourly power demand, is simulated. A brief discussion of PROMIX and the use of PROMIX in this context is presented in Section 1.2.1.

Many simulation tools, however, lack the flexibility to implement such fluctuations in power demand and generation. Models, such as ENPEP (Jusko et al., 1996), use the load duration instead of the chronological demand profile. Other models, such as MARKAL (Fishbone et al., 1983) use strongly simplified demand profiles. Therefore, in the context of these models, detailed modelling of the WECS power generation is not useful or possible and it is often simulated as a constant reduced power output, respecting the annual electric-*energy* output. E.g. if a 1000 MW wind farm has a capacity factor of 30% (or 2630 equivalent full-load hours per year), it is simulated at a constant output of 300 MW.

Many power-generation simulations implicitly use the second method. This means that the power from wind turbines is averaged over the entire year. However, it is our understanding that the validity of such simplifications or assumptions has not yet been verified in detail. Therefore, this study confronts both approaches.

1.2 Methodology for the simulation of wind power generation as part of a larger power system

1.2.1 The power-system simulation tool PROMIX

PROMIX simulates the response of a power system subject to a power demand.

The power system used in PROMIX consists of different separate power plants. The operation of a particular plant is modelled as shown in Figure 1. A plant is divided into separate parts of constant marginal energy use. The first part of the plant is defined as the minimum-operation point, below which it is not operated. When the minimum-operation point is reached, the dispatcher —or in this case the model PROMIX— has to decide whether the plant is to be shut down or further operated at its minimum-operation point while further modulating with other units. A plant can be operated at every level between the minimum-operation point and full load. Apart from the minimum-operation point, PROMIX also considers other technical restrictions of power plants such as the minimum up time and the minimum down time of a plant. Also, the fuels that can be used in the plant are specified. If different fuels are possible, PROMIX selects the most economic option.

The fuel properties in PROMIX are the emissions and the prices. The fuel prices are further on used to optimally dispatch the power generation to the demand. We use the IEA prognoses (IEA, 2004) for the fuel prices for 2010: steam coal at 40 $ per metric ton, natural gas at 3.3 $/MBtu and crude oil at 22 $/barrel. Expressed in $/GJ, these numbers correspond to 1.43 $/GJ for steam coal, 3.1 $/GJ for natural gas and 3.8 $/GJ for crude oil. For nuclear “fuel” we assume a price of 1.09 $/GJ.

The power demand is given on an hourly basis. Since PROMIX is intended to be used on a system level, the possible cross-border interactions need to be implemented exogenously.

We assume that the necessary new investments in the power system from now until 2010 are all combined-cycle gas-fired units.

PROMIX itself simulates the most economic dispatching of the power system on an hourly basis, while respecting the technological restrictions of the individual power plants (e.g. minimum-operation point, minimum up time, minimum down time, output-related primary-energy use according to the plant characteristic of Figure 1). The output of PROMIX consists of the power generation of the separate power plants on an hourly basis as well as the corresponding energy use, primary-energy costs and emissions.

For a more elaborate discussion of PROMIX and some application examples, we refer to Voorspools and D'haeseleer (2000).

1.2.2 PROMIX and the impact assessment of WECS

In this paper, the power generation of WECS is evaluated by using a scenario approach with PROMIX simulations. In one scenario, the base case, no additional WECS are installed. In an alternative scenario, additional WECS are considered. The impact of the power generation of the WECS is evaluated by comparing both scenarios.

In order to evaluate the impact of the fluctuations of wind power, the variations in annual overall CO_2 emissions[1] in comparison to the base case where no additional wind power is installed, are used as a diagnostic.

In order to illustrate our methodology with concrete examples, in this paper, an estimate for the Belgian power system of 2010 is used. In general, this is a 15 GW system consisting of 38% nuclear power, 26% combined-cycle gas, 20% steam-cycle power (gas, coal, oil, blast-furnace gas, coke-oven gas) and 8% cogeneration. This is only the rough outline of the system. In total, there are over 200 different power units in the PROMIX input, all with their own specificities.

2. CASE STUDIES; SIMULATION OF WIND POWER IN BELGIUM

2.1 Wind-power-output profiles

In our concrete case studies, we consider different power-output profiles for four different locations (Figure 2): onshore Vlissingen, near shore Middelkerke, inland Melsbroek and deep inland Kleine Brogel. For these locations, wind-speed measurements are available at 10m height.

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[1] Experience has shown that the CO_2 emissions are a good measure to evaluate variations between scenarios. Although energy costs are the driving force for the dispatching strategy of generators (both in the real world as in our model PROMIX), the variability of energy costs due to the introduction of wind-energy converters is less spectacular than the corresponding variation in CO_2 emissions. When looking, e.g., at the distinction between the differences of the full-load parameters of a coal-fired power station versus a combined-cycle gas-fired unit, the difference in total primary-energy cost ranges from 12-13 €/MWh to 18-20 €/MWh (for the IEA prognoses for 2010), respectively, whereas the change in CO_2 emissions ranges from 800-900 $kgCO_2$/MWh to 350-400 $kgCO_2$/MWh, respectively. Therefore, the CO_2 emissions are used as a measure of variability for the different scenarios.

We assume WECS with a 50m tower. Therefore, the wind speeds are first converted from 10m height to 50m by using the following formula (Grubb and Meyer, 1993):

$$v_{h_2} = v_{h_1} \frac{\ln\ (h_2 / z_0)}{\ln\ (h_1 / z_0)} ,$$

with v_h the wind speed at height h and z_0 the roughness length. We assume the turbines to be built in open terrain with a roughness length z_0 of 0.03m (Grubb and Meyer, 1993). Also, h_1 is 10m at which the measurements are available and h_2 is 50m at tower height.

To convert the wind-speed profile to a power-output profile, we use the power-output characteristic shown in Figure 3. This curve is based on the power curves of the VESTAS V52-850kW turbine (brochure download possible at www.vestas.com).

The resulting normalised power-output profiles for the four locations are partly shown in Figure 4 for Vlissingen, Figure 5 for Middelkerke, Figure 6 for Melsbroek and Figure 7 for Kleine Brogel. The output profiles are shown for three entire weeks: week 1, week 11 and week 25 of the same year for all four locations. The WECS in Vlissingen, Middelkerke, Melsbroek and Kleine Brogel have a capacity factor of 43%, 29%, 20% and 12%, respectively. Apart from these four individual power profiles, we also consider a “mixed” profile in which the sum of an equal amount of installed power at the four locations is considered. The resulting output profile is shown in Figure 8. The capacity factor for this mixed profile is 26%. Note that this combined profile fluctuates less than the individual profiles.

2.2 Different case studies

2.2.1 Base case without additional WECS

Before discussing the results of the scenarios with additional WECS, we present the results for the base-case scenario without additional WECS, because the results of the “alternative” scenarios are all compared to this base case.

In the base case, for an annual electricity demand in Belgium in 2010 of 98.4 TWh/a, we calculate an electricity generation of 95.3 TWh/a with a primary-energy use of 820 PJ/a and corresponding GHG emissions of 28.0 Mton CO_2eq.

The largest contributions in the power-generation mix come from nuclear plants, 42.6 TWh, combined-cycle gas-fired units, 30.6 TWh, cogeneration, 12.30 TWh and coal-fired power stations, 4.95 TWh. The remaining 4.85 TWh comes from blast-furnace and coke-oven gas (mostly in combination with other fuels in a conventional plant), gas-fired (single-cycle) power units, oil-fired power units, waste, hydro and wind (in the base case we already have 100 MW of WECS installed).

As an illustration of the detail of output of PROMIX, Figure 9 shows the power generation and the corresponding greenhouse-gas emissions of the overall system. Each figure is the graphical representation of a large matrix containing 8760 values. From left to right, there are 168 “columns” each representing an hour of the week starting on Monday 06.00h and ending on Monday 05.00h. From top to bottom, there are 52 “rows”, each representing a week of the year. This output is also available for every type of power plant.

2.2.2 Simulations A : actual WECS output profiles, no capacity credit

In a first set of simulations, *Simulations A*, wind power is simulated according to the output profiles based on the actual wind measurements in Vlissingen, Middelkerke, Melsbroek and Kleine Brogel. Apart from the four cases where WECS are installed in one of the four single locations, we also consider the mixed case with an equal amount of WECS in all locations. In all cases, we look at three levels for WECS installation, namely 500 MW, 1000 MW and 1500 MW. At a peak load of about 14.4 GW, this corresponds to installed wind power of 3.5%, 6.9% and 10.4% of peak load.

At this first stage, in *Simulations A*, we disregard the capacity credit[1] which actually means that the power-generation company does not consider the WECS in its investment plan.

In these scenarios, PROMIX simulates the operation of the central power system (conventional power-generating units) whereby the wind-power output is considered as a negative load.

Figure 10 shows the possible reduction in GHG emissions that can be obtained by using WECS in Belgium according to *Simulations A*. In all cases, the emission reduction increases with the WECS installed capacity. This increase, however, is slightly sub-linear. For Vlissingen, e.g., the emission reduction rises from 730 ktonCO$_2$ to 1360 ktonCO$_2$ (factor 1.8) and 2090 ktonCO$_2$ (factor 2.8) for WECS installation from 500 MW to 1000 MW (factor 2) and 1500 MW (factor 3), respectively.

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[1] The capacity credit expresses the amount of installed conventional power that can be avoided or replaced by wind power. This capacity credit is the fraction of the installed wind power for which no “double investment” is needed. E.g., 1000 MW of installed wind power with a capacity credit of 30% can avoid a 300 MW investment in conventional dispatchable power.

Another obvious observation is that the GHG-emission reduction increases with the capacity factor of the WECS. 1500 MW WECS in Vlissingen with a capacity factor of 43% lead to a GHG-emission reduction of 2090 ktonCO$_2$ whereas 1500 MW WECS in Kleine Brogel with a capacity factor of only 12% result in a GHG-emission reduction of 700 ktonCO$_2$.

The mixed profile demonstrates that not only the capacity factor, but also the variability of the profile determines the possible GHG-emission reduction. *With a distinctly lower capacity factor of 26%, the emission-reduction curve of the mixed profile approaches the emission-reduction curve of the Middelkerke profile with a capacity factor of 29%.* 1500 MW WECS in Middelkerke are responsible for an emission reduction of 1370 ktonCO$_2$ whereas 1500 MW WECS distributed evenly over the four locations lead to an emission reduction of 1340 ktonCO$_2$.

In all cases considered in this section, the potential emission reduction is about 350 to 400 kgCO$_2$ per MWh of WECS power generation. This suggests that the WECS largely replace power that would otherwise have been generated by combined-cycle gas-fired units. The power-generation mix in the cases of *Simulation A* with 1500 MW WECS, as shown in Figure 11, confirms this observation. Also note that, in the cases with 1500 MW WECS, limited modulation with the nuclear units in base load is inevitable in order to cope with the strong possible power fluctuations.

2.2.3 Simulations B : WECS at constant reduced output, no capacity credit

Since many simulation models lack the ability to handle detailed WECS output profiles, the power generation of wind turbines is often modelled as a constant reduced output.

To verify the validity of this simplification, the scenarios of *Simulations A* are repeated under the assumption of a constant reduced wind-power output. In order to respect the capacity factor, the wind turbines are assumed to be constantly available at reduced power of 43%, 29%, 20% and 12% of rated power for Vlissingen, Middelkerke, Melsbroek and Kleine Brogel, respectively, and 26% for the mixed profile.

The result of the CO_2 emission reductions in comparison to the base case without additional wind power is shown in Figure 12 for Vlissingen and the mix of WECS at four locations. The result for the simplified approach with WECS at constant reduced power is compared to the result using the actual fluctuating profiles. For the WECS in Vlissingen, the approach using the constant reduced power output slightly overestimates the potential GHG emission reduction by approximately 14 to 15% in all cases. For the other individual profiles (Middelkerke, Melsbroek and Kleine Brogel), a similar “overshoot” is observed. For the mixed profile, the overestimation is smaller at about 10 to 11%.

The reason for the overestimation when using the constant reduced power output of WECS is that the power system can be used more efficiently (especially the base-load scheduling) because it does not have to cope with the fluctuation of the WECS output. Anyway, the overshoot is limited.

2.2.4 Simulations C : actual WECS output profiles + capacity credit

In a third set of scenarios, we take into account the capacity credit of the WECS. This means that the WECS replace other “conventional” generating capacity. Because wind power is not constant and cannot be dispatched, only a fraction —the capacity credit— of the installed WECS is taken into account.

Based on the work of Van Wijk (1990) who studied WECS in the Netherlands (close to Belgium and therefore in similar wind conditions), we estimate the capacity credit for our case. In *Simulations C* with capacity credit, we only consider the case with a mix of WECS in the four locations because the capacity credit taken from Van Wijk (1990) is only valid for a comparable spread of wind farms. We estimate the capacity credit of the 500 MW, 1000 MW and 1500 MW wind farms at 140 MW (or 28%), 240 MW (or 24%) and 310 MW (or 21%), respectively. Since we only assume investment in combined-cycle gas-fired units in the period up to 2010, this means that 140 MW, 240 MW and 310 MW, respectively, investment in combined cycles is avoided.

Figure 13 shows the results for the scenarios in *Simulations C* in comparison with the results for *Simulations A* without capacity credit. This comparison shows that the capacity credit reduces the GHG-emission-reduction potential by using WECS in a power system. The obvious reason for this unfavourable effect is that the avoided investment in gas-fired capacity —if it had been built— would have partially replaced “other” conventional-power generation with a higher emission responsibility. Here, WECS cause an emission reduction of about 350 kg per MWh of the power generated by the WECS. This is slightly less than the 400 kg/MWh for the case with a mix of WECS without capacity credit in *Simulation A*.

Figure 13 also shows the GHG-emission reduction that is calculated when assuming the WECS at constant reduced power output, for the mixed case, of 26% of rated power. Here, we also observe a small overestimation of the reduction potential of about 14%, which is comparable to the overestimation noted in the cases without capacity credit.

2.2.5 Simulations D : actual WECS output profiles + CO_2 tax

Up till now, all results have been discussed for the Belgian power-generation mix under the boundary conditions of the IEA prognoses of the energy prices. Since the GHG-emission-reduction potential of using WECS is strongly determined by this power-generation mix, it would be interesting to also investigate other generation mixes.

In order to test the influence of the generation mix, the energy prices are supplemented with a CO_2 tax of 10 €/tonCO_2. Such a tax drastically alters the proportions of the energy prices depending on the carbon content of the different fuels. The fuel prices including the tax component are now 2.39 €/GJ for coal (of which 0.96 €/GJ from the tax), 3.71 €/GJ for natural gas (of which 0.59 €/GJ from the tax) and 4.62 €/GJ for crude oil (of which 0.78 €/GJ from the tax). The emission free nuclear fuel remains at 1.09 €/GJ.

Without changes in the composition in the power system, the generation mix in the new base case including the tax alters. The coal-fired share in the power generation decreases from 5.2% (or 4.95 TWh) in the base case without taxes to 3.3% (or 3.14 TWh) in the new base case with a CO_2 tax of 10 €/tonCO_2. The gas-fired share increase from 33.0% (or 31.4 TWh) to 34.9% (or 33.3 TWh), respectively. The other generation shares remain the same.

Figure 14 shows the results in which the scenario with additional WECS is compared to the scenario without additional WECS, in an environment with a CO_2 tax of 10 € per metric ton CO_2. Also the results for the same scenarios without additional taxes are shown for comparison. We only look at the results for the case with a mix of WECS in the four locations and we do not consider a capacity credit. In a CO_2-tax environment, the GHG-emission-reduction potential is larger than in the case without the CO_2 tax. The GHG emission reduction compared to the respective base cases is about 12 to 15% higher for all penetration levels. This is unexpected at first sight. Although the base case with a CO_2 tax is less polluting (since a part from the power generation is shifted from coal to gas), the effect on CO_2 reduction thanks to wind power is larger than in the environment without CO_2 tax. When looking at the emission reduction per unit of WECS power generation, we find about 450 kg/MWh. Figure 15 shows the power-generation mix for the cases with and without CO_2 tax. The results on the left hand side already appeared in Figure 11; the results on the right hand side are the results for the corresponding scenarios with CO_2 tax. It is clear that the CO_2 tax reduces the share of the coal-fired generation as already discussed earlier.

Figure 14 also shows the GHG-emission reduction that is calculated when assuming the WECS at constant reduced power output, for the mixed case, of 26% of rated power. Here, we also observe an overestimation of the reduction potential of about 20%, which is higher than for the same cases without CO_2 tax.

2.2.6 Considerations and suggestions for future research

2.2.6.1 Considerations on the spread of wind farms

The wind profiles used in the simulations discussed in the previous sections are all based on the wind measurements at one singe location. The mix case assumes equal share of WECS in four different locations, still within a radius of 100 km, varying from onshore to inland. The result of using a wider spread of wind farms (as, e.g. the entire EU territory as used by Giebel, 1999, and Landberg, 1997) is that the combined power-output profile is smoother than the profiles for WECS at single locations. The *local* variations in power generation will nevertheless still mainly need to be compensated with local generation.

The analysis of wind data at the four locations in Belgium shows a strong correlation between the wind speeds. The reason for this strong correlation is the small distance between the locations and the lack of complex topography. Furthermore, it is noted that these correlations improve when the power output profiles are shifted in time over one or two hours. Indeed, the dominant wind direction in Belgium first supplies the coastal wind turbines to later on “feed” those inland. This time shift between profiles results in an overall joint power generation less peaked than those based on data for a single location.

The simulations with the profile at one location as discussed in the previous parts of this Section 2 can therefore be considered as one extreme. The simulations using a constant power as discussed in Section 2.2.3 can be considered as another theoretical extreme of a very widely spread wind-farm resulting in a combined constant power output. From a simulation point of view, Figure 12 shows the difference between these two extreme cases. The constant WECS output profile has a slightly larger GHG-emission-reduction potential than the strongly fluctuating profile. These differences are, however, limited to about 10 to 15%.

2.2.6.2 Belgium versus other regions

For all the simulations discussed above, the Belgian power-generation system was used. From a modelling point of view, this is a very interesting power system due to its variety in power plants; nuclear base-load units, coal- and gas-fired mid-load units, gas- and oil-fired peak units and pumped-storage units. The variety in energy carriers will result in a large possible swing in CO_2 emissions; from 1000 kg/MWh for older coal-fired power plants to 0 kg/MWh for nuclear power plants. Simulations for other regions with less variety in power-generating options (e.g. the Dutch system with a larger share of gas-fired power generation) will lead to smaller deviations and variability of the CO_2 emissions. Therefore, we assume that our qualitative conclusions —i.e. the difference between the different cases— based on the CO_2-emission variations of a system with large potential CO_2 swing, are also valid for other systems with a lower potential CO_2 variability. The quantitative results —i.e. the total amount of GHG-emission reduction— is evidently determined by the generation mix and is system dependent.

As a next step in future research, it would be interesting to also include other regions with a different generation mix.

2.2.6.3 Influence of energy prices

All simulations up till now have been performed for the 2004 IEA prognoses for energy prices (IEA, 2004). In Section 2.2.5, we imposed a CO_2 tax of 10 €/tonCO_2 which distorted the resulting energy prices. It was shown that the changes in energy prices and the resulting alteration of the power-generation mix does indeed influence the quantitative results; with a CO_2 tax, the GHG-emission-reduction potential of WECS increased.

Therefore, it would be interested to further apply our methodology to other plausible distortions of energy prices.

3. CONCLUSIONS

This paper discusses a methodology to accurately determine the impact of the use of wind energy in a large power-generating system. To do so, detailed data of both the wind-power output and the power system and all of its technological boundary conditions are combined. The power generation of the central power system is simulated on an hourly basis using the model PROMIX. The impact of the use of wind power is identified by comparing two scenarios; one base case without additional WECS and one alternative case with WECS.

The method is demonstrated in an elaborate case study for Belgium in 2010. The entire power system is simulated in detail by considering every individual power plant with its own technological specifications. For the wind-power generation, hourly wind-speed measurements in four different locations are used: onshore Vlissingen, near shore Middelkerke, inland Melsbroek and deep inland Kleine Brogel. These wind-speed profiles are converted into power-generation profiles by using the characteristics of a commonly used wind turbine.

Different cases are studied. In all cases, we look at the GHG-emission-reduction potential of the installed WECS.

- In a first set of scenarios, the chronological power-output profiles are tested for all four locations and for a geographical spread of WECS over the four sites.
- A second set of scenarios simplifies the power output of the WECS as a constant reduced power output by assuming that the WECS constantly generate a fraction, more specifically the capacity factor, of rated power.

- In a third set of scenarios, the capacity credit of the WECS is considered.
- In a fourth set of scenarios, we include a CO_2 tax for primary-energy carriers which changes the price ratios of the different fuels according to their carbon content.

As a first conclusion, we find that in all cases considered, the GHG-emission reduction obtained on a national level is in the range of 350 to 450 kgCO_2 per MWh of power generated by the WECS. By way of comparison, we mention that the overall emissions of the Belgian system are about 300 kg/MWh for the complete system and almost 500 kg/MWh for the dispatchable fossil-fuel fired part of the generation mix.

The emission-reduction potential increases if more WECS are installed. We observe that the increase in emission reduction is slightly sub-linear with the increase in installed power. If the installed power increases with a factor X, the emission reduction increases with a factor slightly below X.

Another observation is that the emission-reduction potential is larger for smoother WECS-power-output profiles due to a more efficient use of base-load units. Two extreme situations with on the one hand strongly fluctuating profiles of WECS in one single location and on the other hand constant power-output profiles show a difference of about 10% to 15% in overall emission reduction.

In the scenarios with a CO_2 tax, the emissions are, evidently, lower than in the same scenarios without CO_2 tax. Also the emission-reduction potential of WECS increases when assuming a CO_2 tax. The merit order of the coal-fired power plants is high under a CO_2 tax which makes them more eligible for incremental changes in central power delivery imposed by using WECS.

When taking into account the capacity credit of the WECS, the emission-reduction potential of using WECS decreases compared to the cases where no capacity credit is taken into account. This has everything to do with the natural emission reduction obtained by renewing the power system. We assume that new and highly efficient combined-cycle gas-fired units are the most eligible candidates for new investments. These units replace older units which are less efficient and produce higher emissions. The capacity credit partly inhibits this evolution which leads to a lower reduction potential. It should be noted that, in the real world, the market will decide to what extent the capacity credit will be taken into account.

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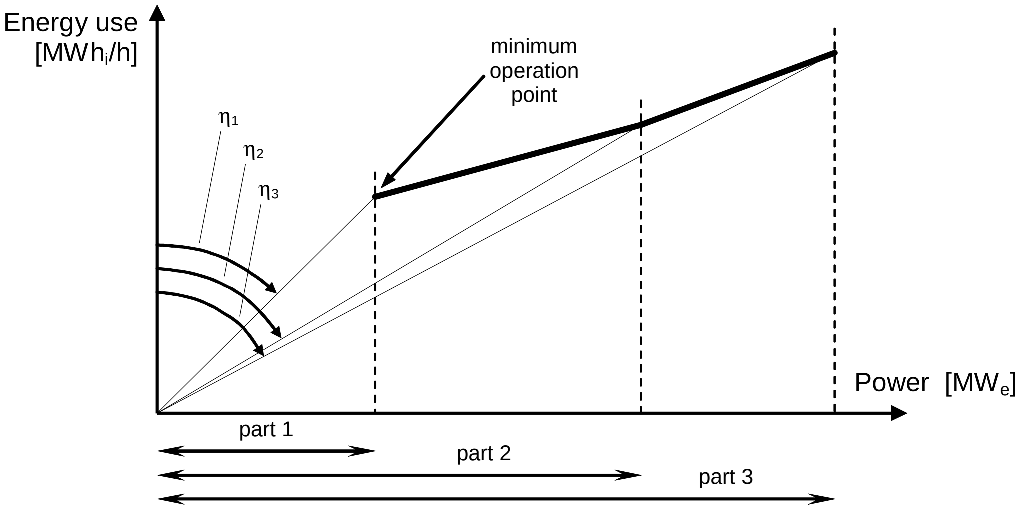

Figure 1 : Operation of a power plant as used in PROMIX. A plant is divided in different parts of constant marginal energy use

Figure 2 : Map of Belgium with the indication of four locations of wind-speed measurements

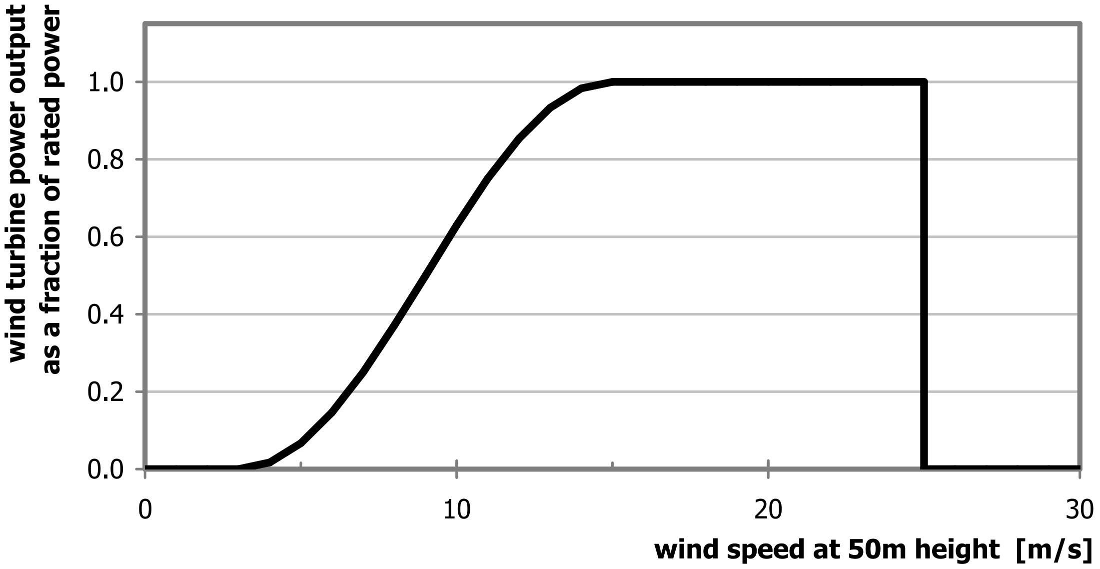

Figure 3 : Wind-turbine power output as a function of the wind speed at 50m height (based on the data for the VESTAS V52-850kW turbine)

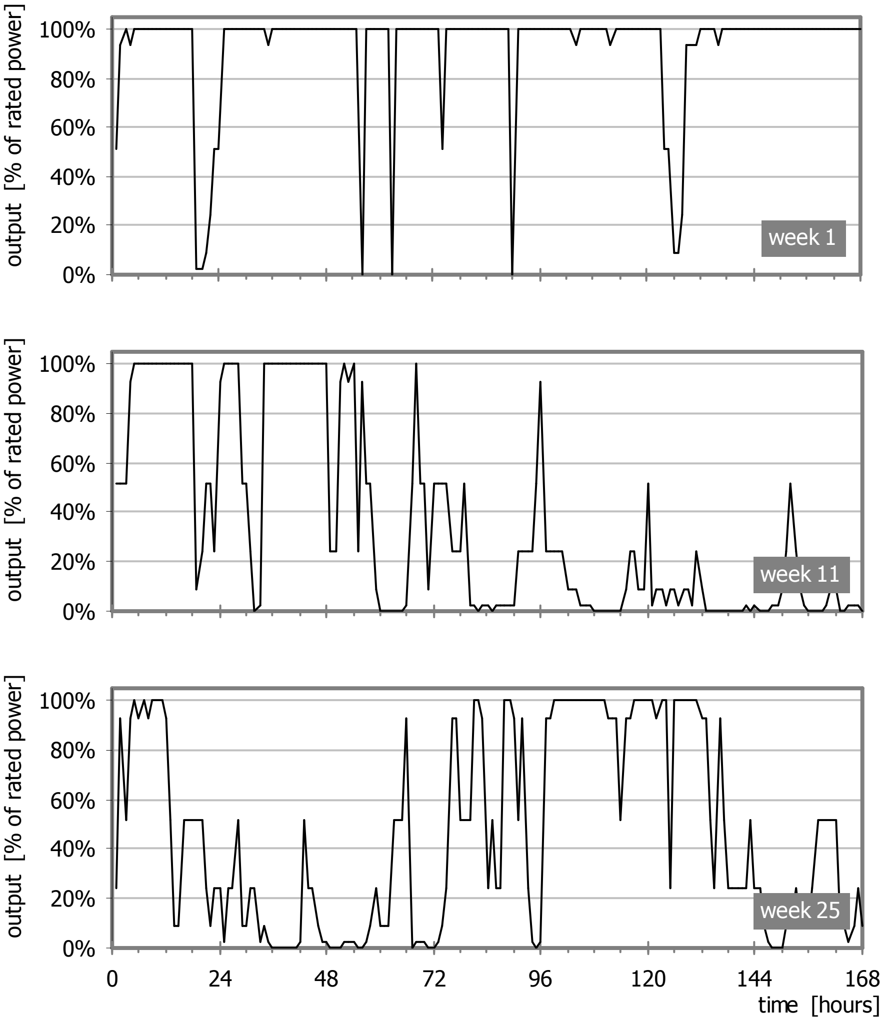

Figure 4 : Normalised fluctuating generation profile for wind turbines in Vlissingen (coast) with overall annual capacity factor of nearly 43%. The profiles for weeks 1, 11 and 25 are shown.

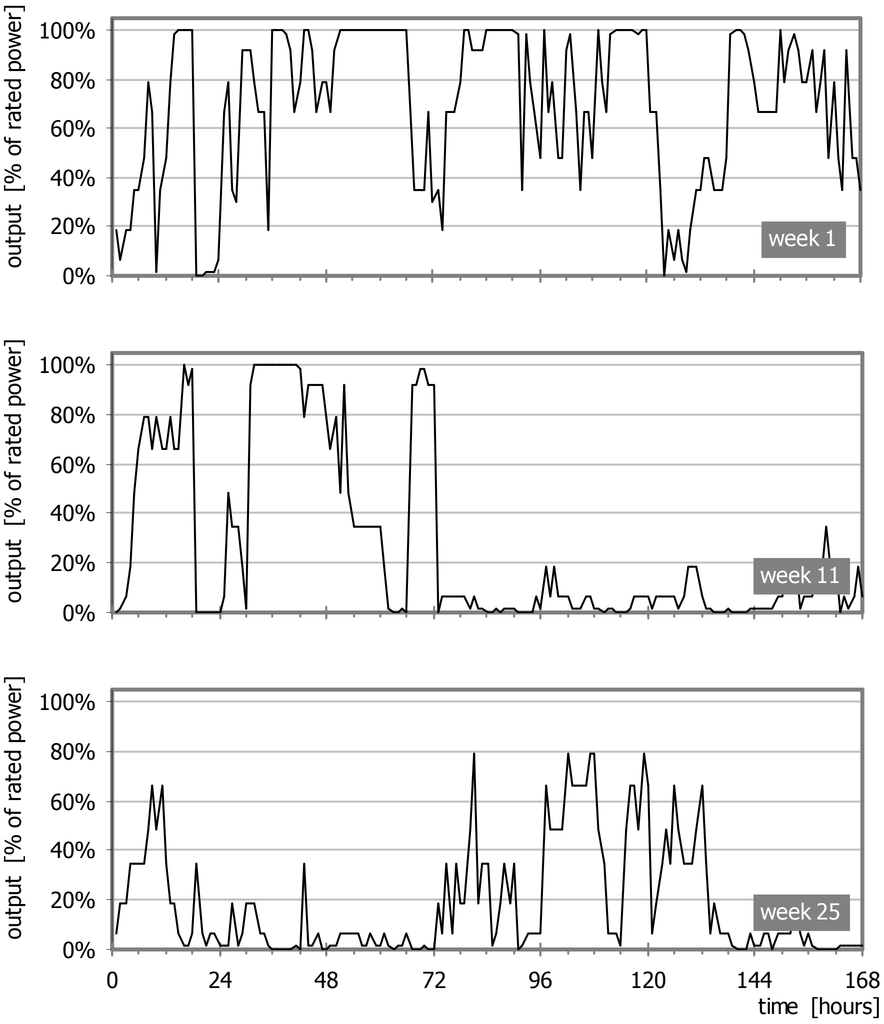

Figure 5 : Normalised fluctuating generation profile for wind turbines in Middelkerke (near cost) with overall annual capacity factor of nearly 29%. The profiles for weeks 1, 11 and 25 are shown.

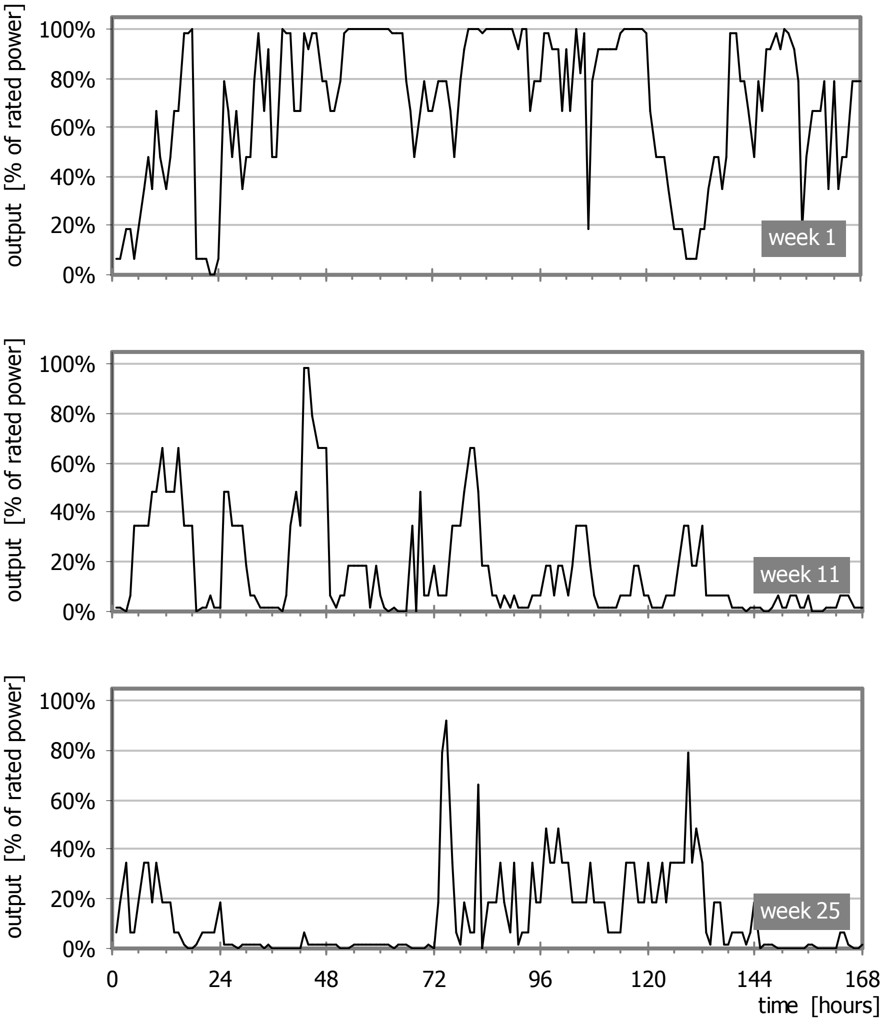

Figure 6 : Normalised fluctuating generation profile for wind turbines in Melsbroek (inland) with overall annual capacity factor of 20%. The profiles for weeks 1, 11 and 25 are shown.

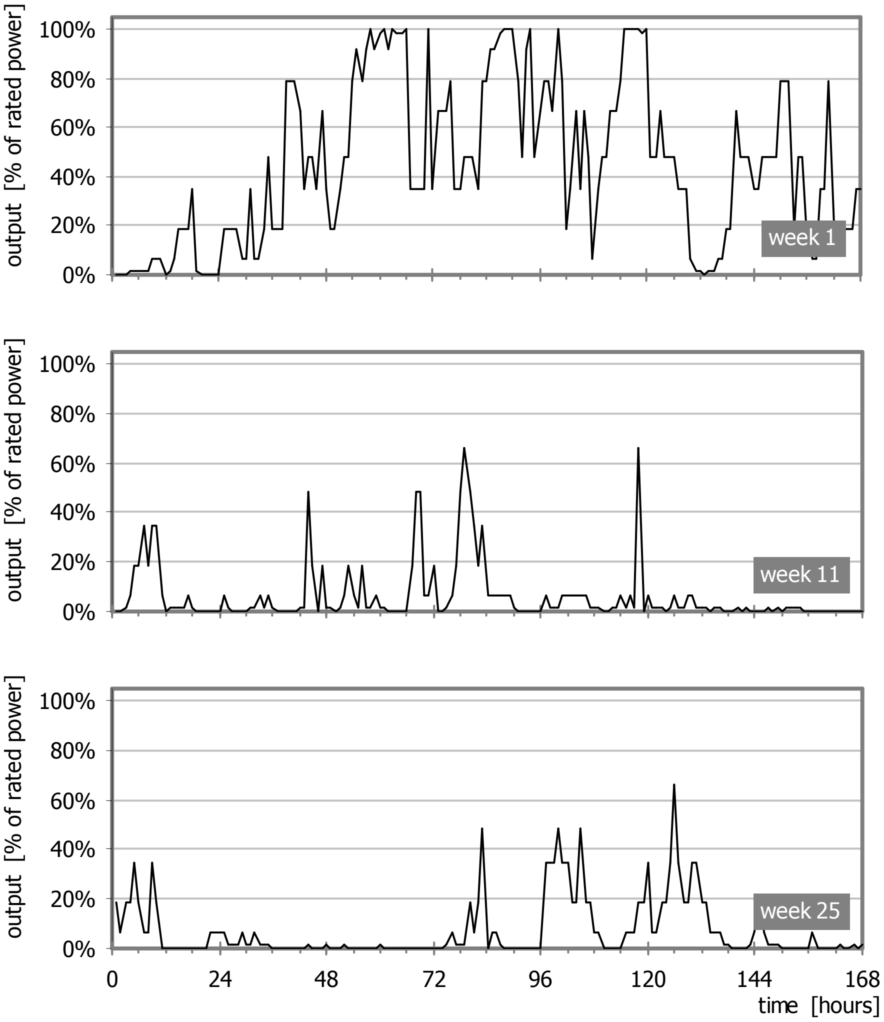

Figure 7 : Normalised fluctuating generation profile for wind turbines in Kleine Brogel (deep inland) with overall annual capacity factor of 12%. The profiles for weeks 1, 11 and 25 are shown.

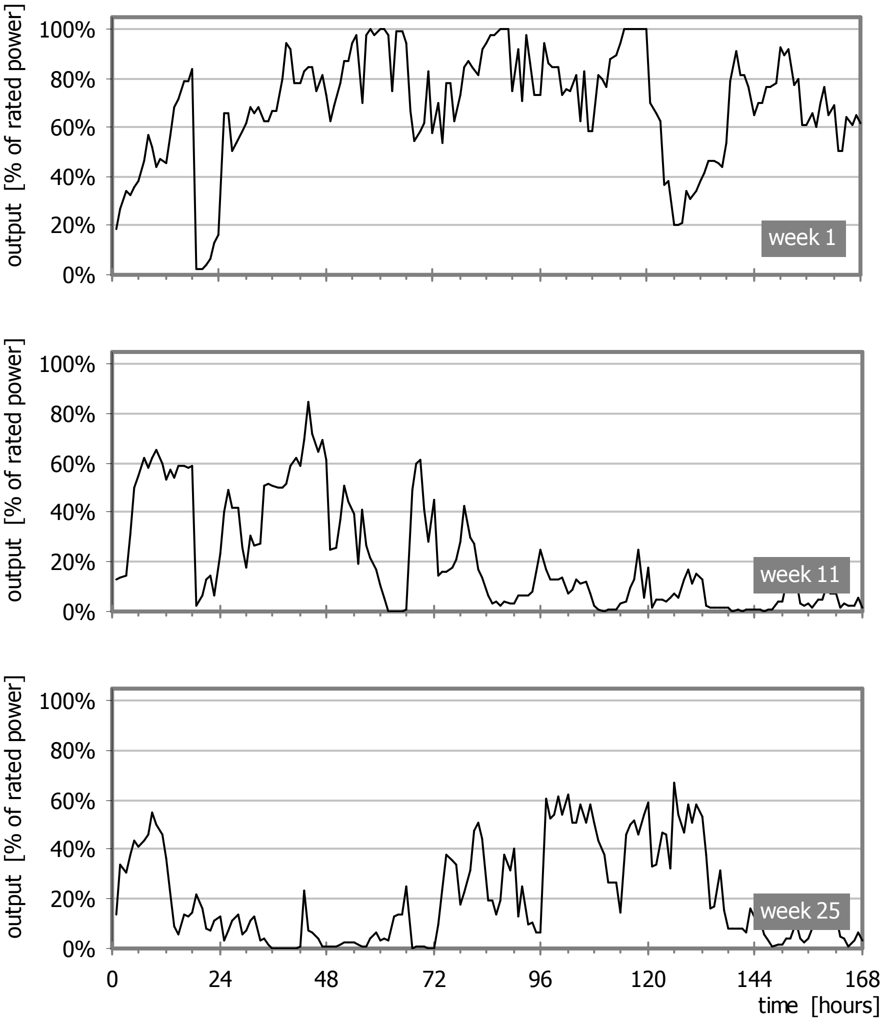

Figure 8 : Combined normalised fluctuating generation profile for equal amounts wind turbines in Vlissingen, Middelkerke, Melsbroek and Kleine Brogel with overall annual capacity factor of nearly 26%. The profiles for weeks 1, 11 and 25 are shown.

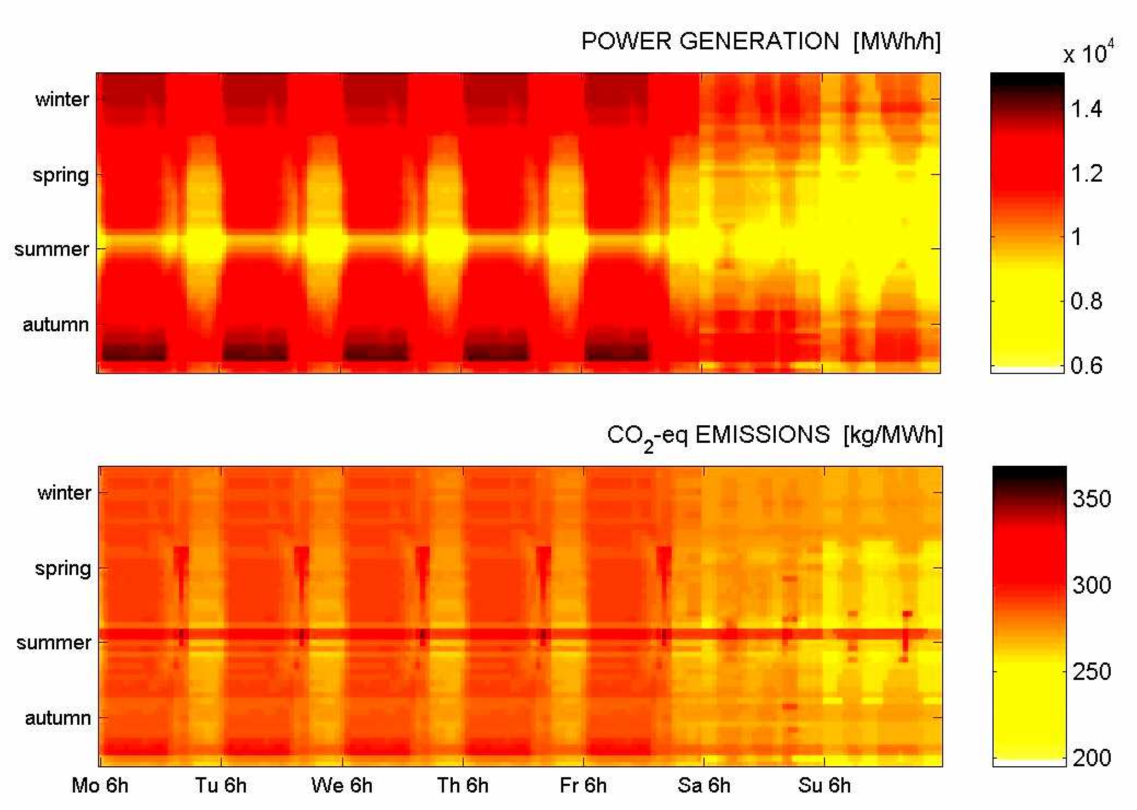

Figure 9 : PROMIX output; power generation and GHG emissions for every hour in the base-case scenario

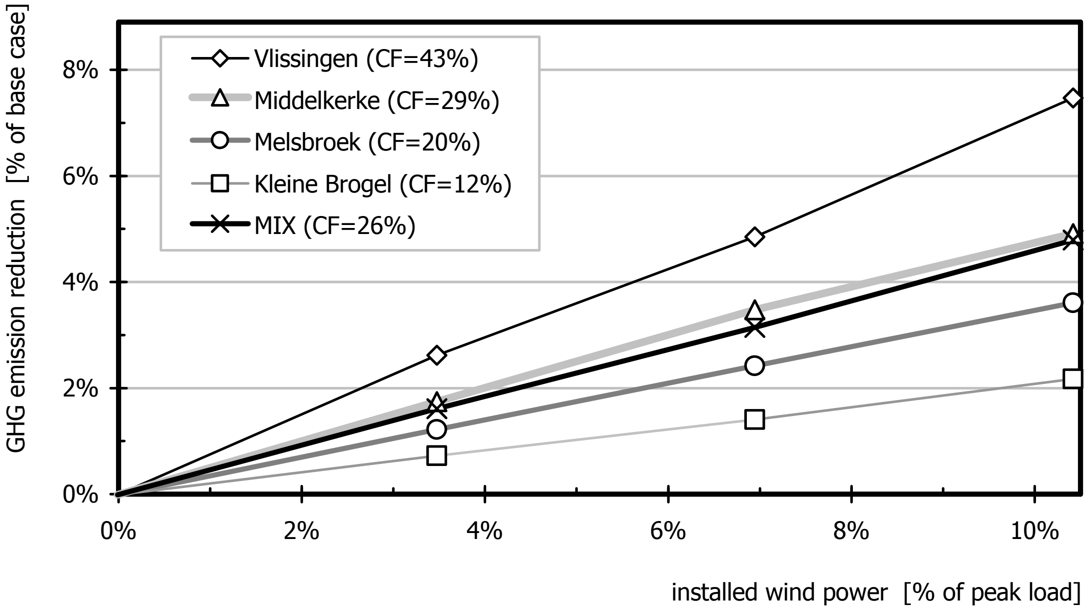

Figure 10 : Impact of wind-power generation on the overall GHG emissions in power generation; results for “Simulations A” with the actual WECS power-output profiles and without capacity credit

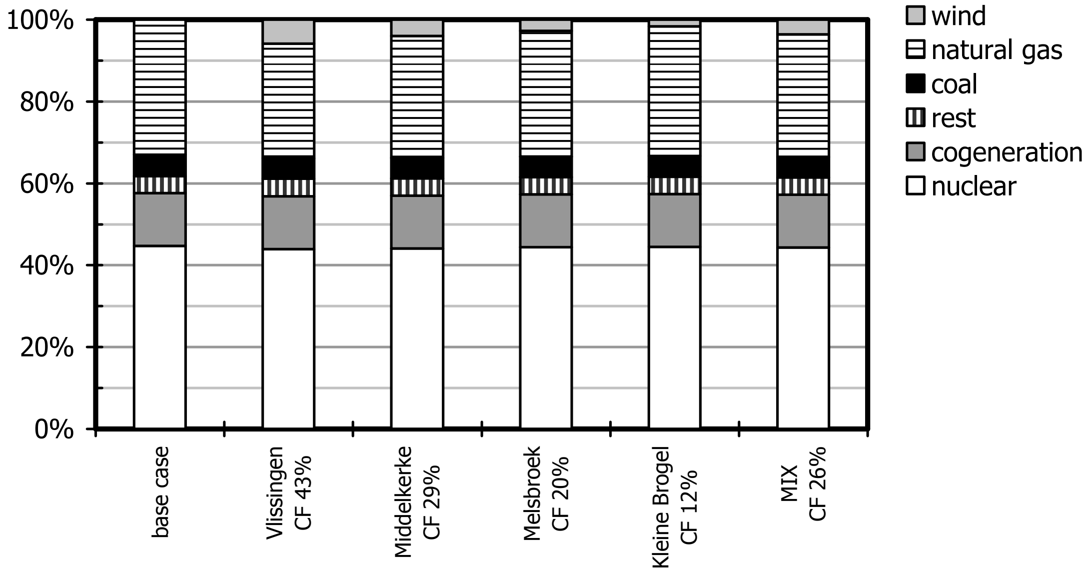

Figure 11 : Power generation mix in the cases of "Simulations A" with the actual WECS power-output profiles and without capacity credit and 1500 MW WECS

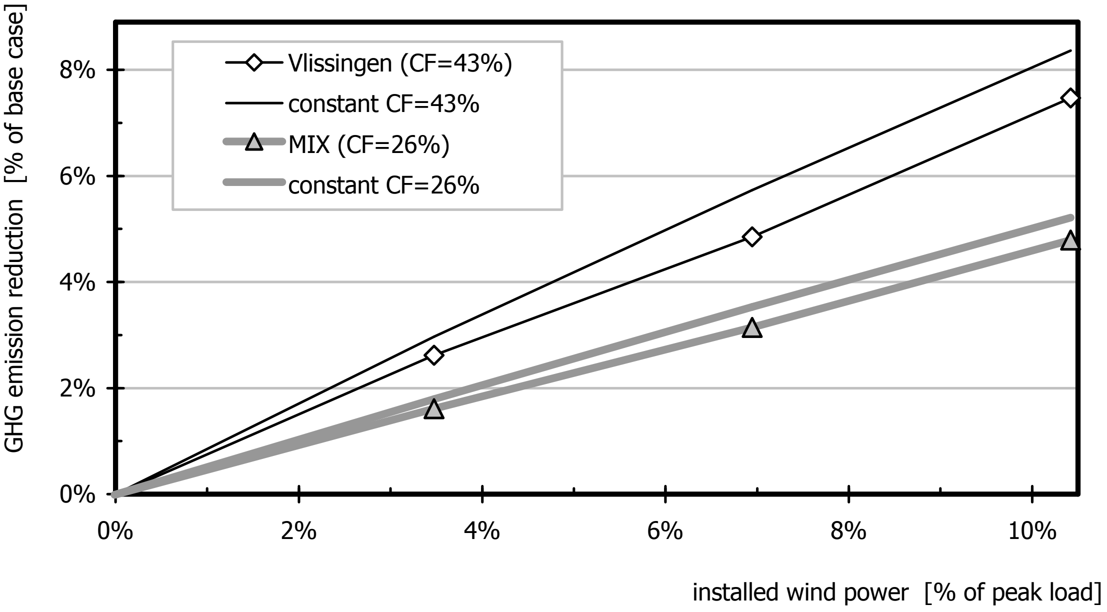

Figure 12 : Impact of wind-power generation on the overall GHG emissions in power generation; comparison of the results with the actual WECS power-output profile and the results with WECS at constant reduced power output; results for Vlissingen and the mix of WECS at four locations

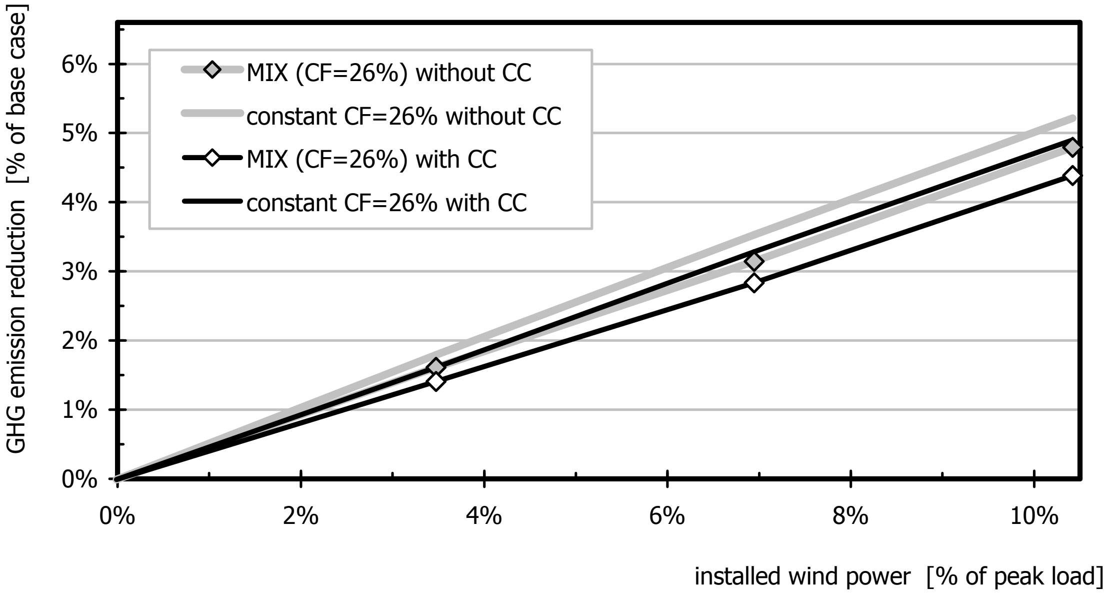

Figure 13 : Impact of wind-power generation on the overall GHG emissions in power generation; comparison of the results without capacity credit and the results with capacity credit

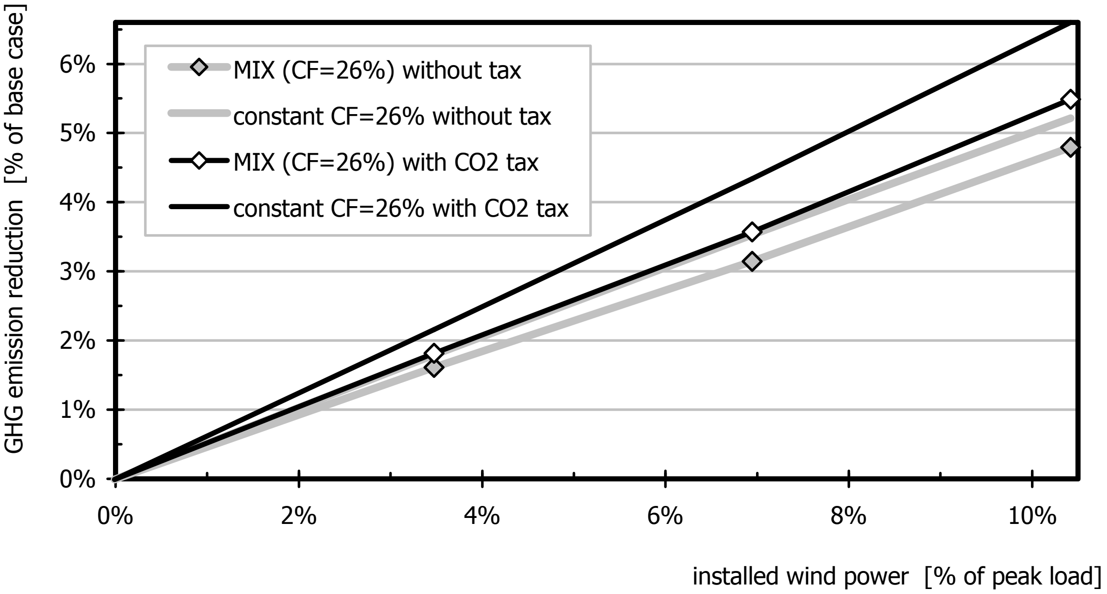

Figure 14 : Impact of wind-power generation on the overall GHG emissions in power generation; comparison of the results without additional taxes and the results with a 10 €/tonCO_2 tax

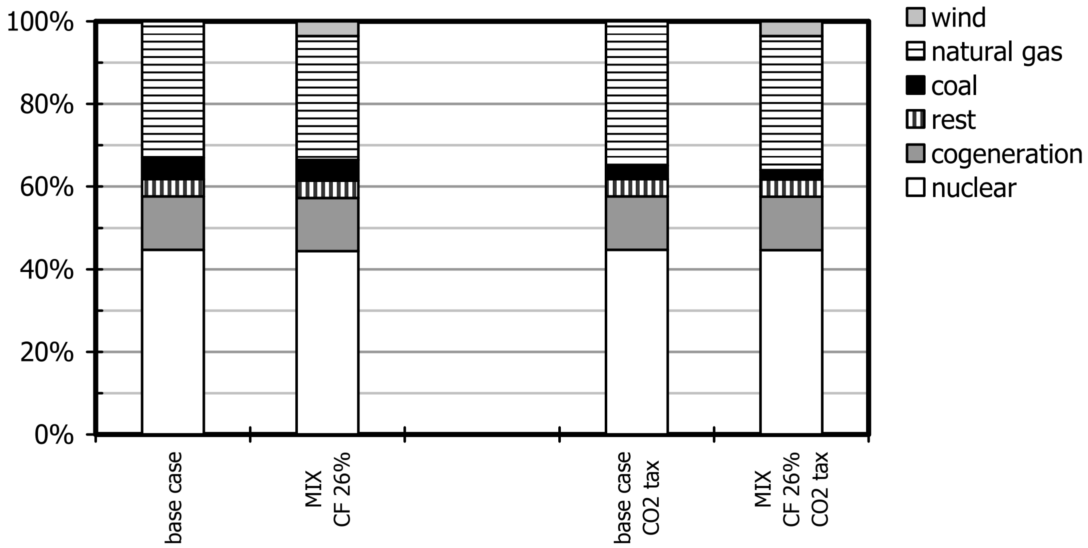

Figure 15 : Power generation mix for the cases with and without CO_2 tax. No capacity credit in these cases.