

**The Role of Wind Generation in European Power Sector Decarbonization: A
General Equilibrium Analysis**

by

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Abstract

Wind generation has been growing fast, with onshore wind having a 27% average annual growth rate over the past decade. Motivated by this growth, a comprehensive analysis of both the economic and engineering implications of a large wind penetration in power systems was conducted.

In order to understand and capture the unique characteristics of wind generation different tools and methods were combined. First, an analysis of hourly wind and load profiles was completed for individual European countries and for the whole European region. Then, a detailed electricity model was used in order to capture the effects of a large wind penetration (up to 60% of total demand) on the power system. Finally, this information was integrated in a computable general equilibrium (CGE) model, the MIT EPPA model - a tool for analyzing the economy-wide implications of energy and climate policies. Based on the bottom-up modeling results, a new methodology for capturing wind intermittency in EPPA, through modeling system flexibility requirements at large wind penetration levels, was proposed. As a case study, a 40% and an 80% GHG emissions reduction scenarios by 2050 (relative to 1990 levels) were modeled for Europe.

The analysis illustrates that, in order to mitigate wind intermittency, particularly for large wind penetration levels, a system needs to have enough flexible capacity installed - traditionally provided by gas or hydro technologies. However, it is shown that for a significant emissions reduction scenario (80% GHG reduction in Europe by 2050), providing this flexibility from the generation side might be challenging as low-cost, low-carbon, flexible, dispatchable technological options might be limited. This might impose a constraint on the total electricity use and on the growth of wind penetration. Thus, the importance of considering other options for providing flexibility in the system, such as storage, demand response or interconnections is displayed. In particular, the wind and load profile analysis indicates a high value of interconnecting wind farms in the European region.

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1 Research Motivation

As the need for taking action against climate change becomes stronger, countries around the world have been imposing targets on their emission levels. In the power sector, low emission scenarios are associated with a high penetration of renewable energy sources, mainly wind and solar energy (IEA 2012). However, these renewable resources present different characteristics compared to conventional generation technologies that have traditionally been used, which might make the transition to them challenging from a technical and economic perspective. For example, wind is variable over time and imperfectly predictable, making it harder for system operators to match generation and load at every moment.

The aim of this work is threefold: First, to analyze the characteristics of wind generation that distinguish it from traditional generation technologies; then, to determine the effects of a large wind penetration on power systems operation; finally, to integrate these effects in a top-down computable general equilibrium (CGE) model, used for analyzing energy and climate policies.

Even though the production of conventional technologies is not perfectly predictable either (a common forced outage rate of coal or gas-fired plants would be around 6%) (Vuorinen 2007), this characteristic is more intense in the case of wind generation. A typical maximum error in day-ahead wind prediction is in the order of 20% (Perez-Arriaga et al. 2012). Even if wind could be totally predicted, however, it would still be variable, which means that there should be other technologies in the system able to generate power fast enough, in order to cover demand when wind changes quickly. This characteristic of wind generation, i.e., the intra-day and intra-hourly changes in wind output, combined with a rapid growth of wind in a number of countries, has targeted public attention on the implications of large wind penetration levels in the system.

Solar PV generation presents similar characteristics but to a smaller extent since the solar production pattern is more predictable (e.g. solar plants don't produce at night). Other renewable generation options, such as biomass-fired plants or concentrated solar power (CSP) plants with thermal storage or geothermal have more predictable production patterns and can be treated like conventional thermal plants within a power system. The term Variable Renewables, when used in this work, does not refer to these dispatchable renewable technologies. In fact, generation from all renewable technologies can vary, as shown in Figure 1, but at different timescales.

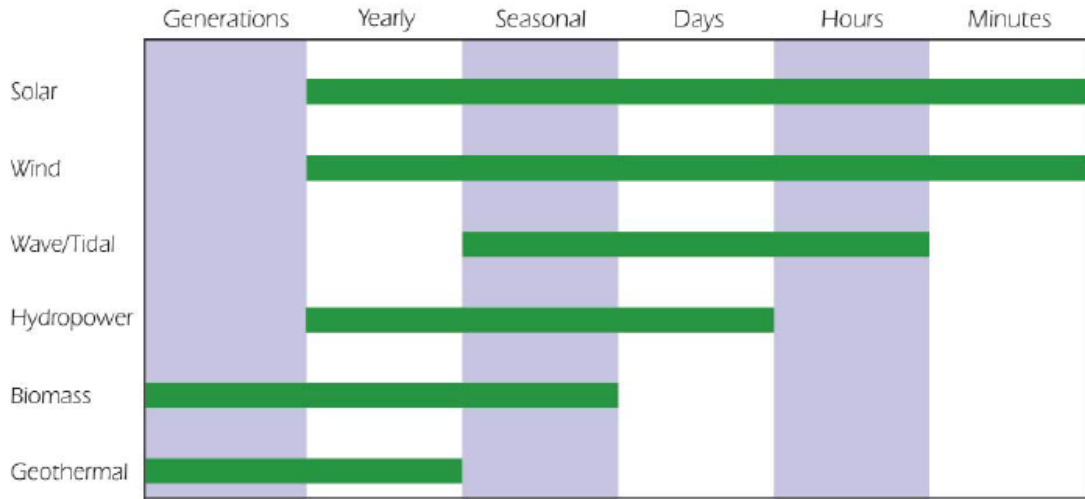


Figure 1 - Variability timescales for different renewable technologies (Source: IEA 2005)

What is interesting about wind, however, which has also been a main motivation for focusing on this particular technology, is its fast growth rate. According to IEA (2012) onshore wind has seen 27% average annual growth over the past decade. It is among the most cost-competitive renewable energy sources and can now compete without special support in electricity markets endowed with steady winds (e.g. New Zealand or Brazil).

Particularly, in the European region annual wind power installations have increased steadily over the past 17 years from 814MW in 1996 to 9,616 MW in 2011, an average annual growth rate of 15.6% (Figure 2).

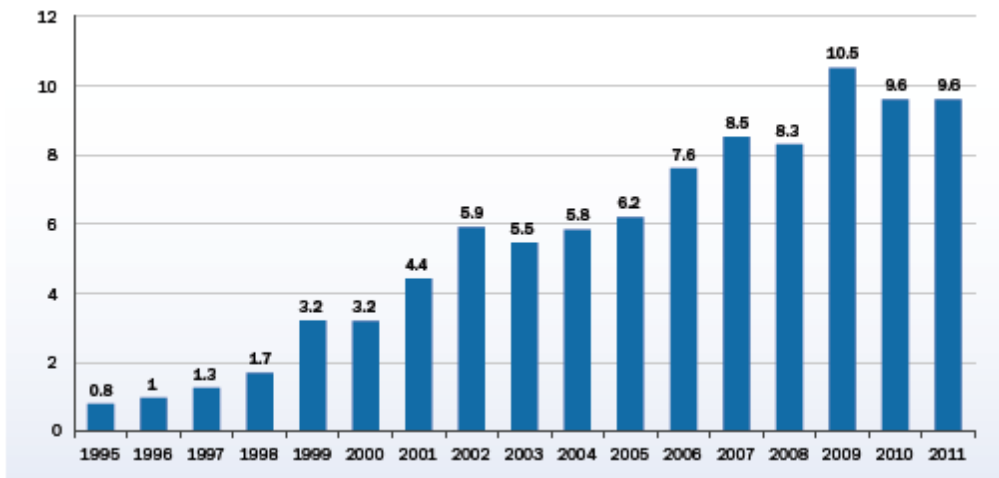


Figure 2 - Annual wind power installations in EU in GW (Source: EWEA 2012)

Therefore, studying the implications of this large increase in wind penetration in power systems over the following years is an issue of interest. Of course, a future analysis (similar to that for wind) can focus on the impact of other renewable technologies on the system when they reach large penetration levels.

1.1 Power Systems Operation

In order to better understand why wind intermittency¹ might be a challenge the way power systems operate should be considered. The main requirement that drives power systems operation is the need to always maintain a balance between generation and demand, as storage capacity is limited due to mainly economic reasons. Some issues related to energy storage are described in Section 3.1. In a particular place demand fluctuates depending on the hour of the day, the day of the week and the season of the year. For example, demand is normally lower during the night compared to the daytime. Also, demand patterns over the weekdays are similar but change over the weekend, following people's activities. These weekly patterns can be clearly seen in Figure 3 for the case of Great Britain. In places with mild winters and hot summers, such as the Mediterranean countries, the annual peak demand tends to occur in the summer due to increased used of air-conditioning. On the other hand, places with cold winters where electric heating is used tend to have their peak demand over winter months.

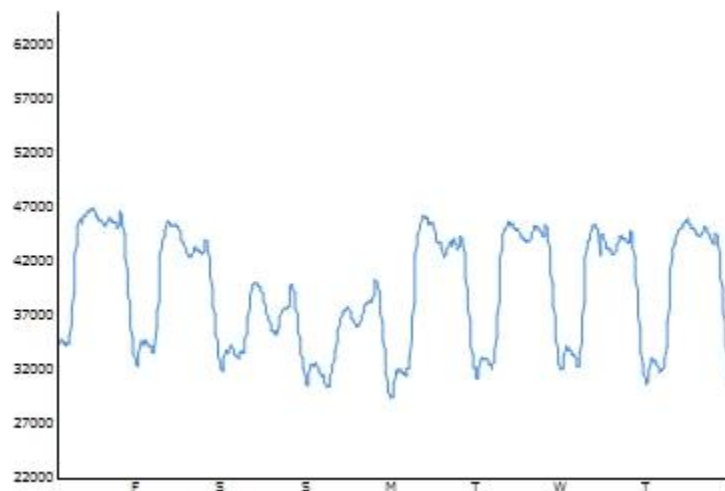


Figure 3 - Electricity demand in Great Britain for the week 4/5/2013-4/12/2013
(Source: <http://www.nationalgrid.com/uk/Electricity/Data/Realtime/Demand/Demand8.htm>)

Generation must constantly meet these fluctuations in demand. The demand curve can be divided in three load levels - base, intermediate and peak load - even though the distinction between

¹For simplicity in this work the terms intermittency and variability will be used interchangeably.

these parts is not very clear. Accordingly, generation units can be approximately categorized within one or more of these levels. In particular, base load units (including nuclear or coal plants) operate during most of the year. Peaking units (such as Open Cycle Gas Turbines) operate for a limited number of hours each year when demand is at its peak. Load-following units change their output based on demand fluctuations. These can be, for example, Combined Cycle Gas plants. A visual representation of the different load levels and how they are met by different units is shown in Figure 4 below. This graph is the outcome of a Unit Commitment electricity model through which each generating unit is "committed" to generate at a particular hour so that total demand is met with a specified probability.

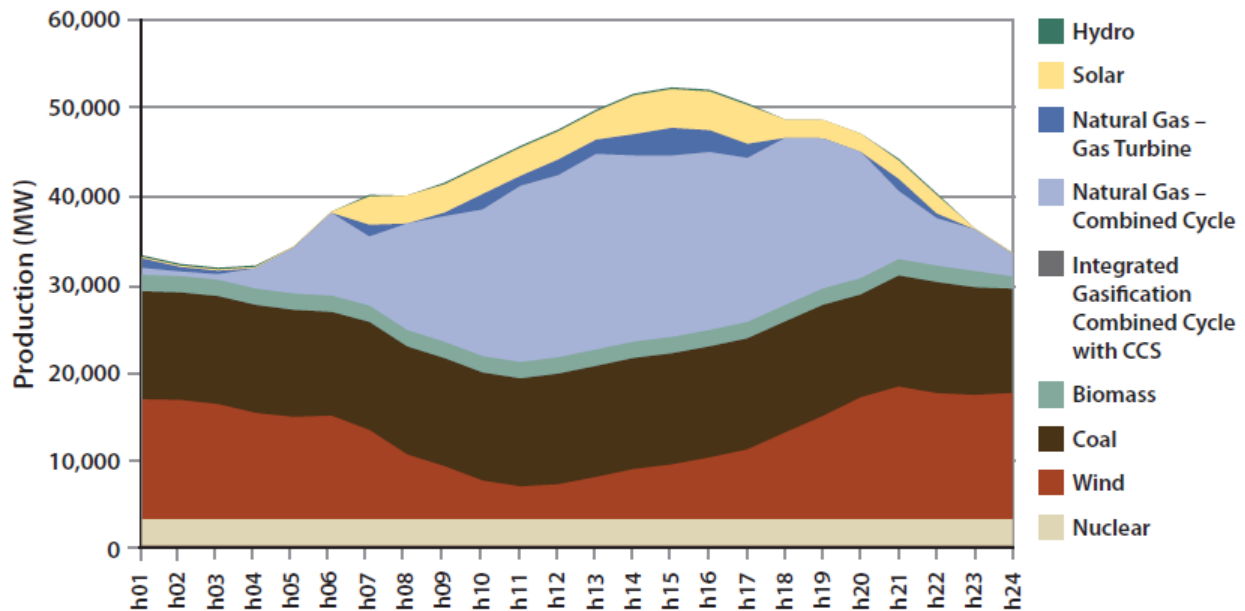


Figure 4 - A possible 24-hour dispatch of generation units to meet the load (Source: MIT 2012).

Each power system operates under tight security and quality standards. Security standards dictate that the electricity grid must be designed to withstand outages of certain magnitude and high loads without losing service. Quality standards define the exact nature of the electricity service delivered, the frequency and voltage being two important variables of this. Based on these criteria an operator has to enable enough reserve capacity to be able to maintain the specified security and quality of electricity supply in the face of major events (outage of the largest individual generating unit on the grid or the loss of the most significant transmission line).

When wind generation is introduced in a system it affects the dispatch of thermal units as shown in Figure 5 for the case of the Spanish system.

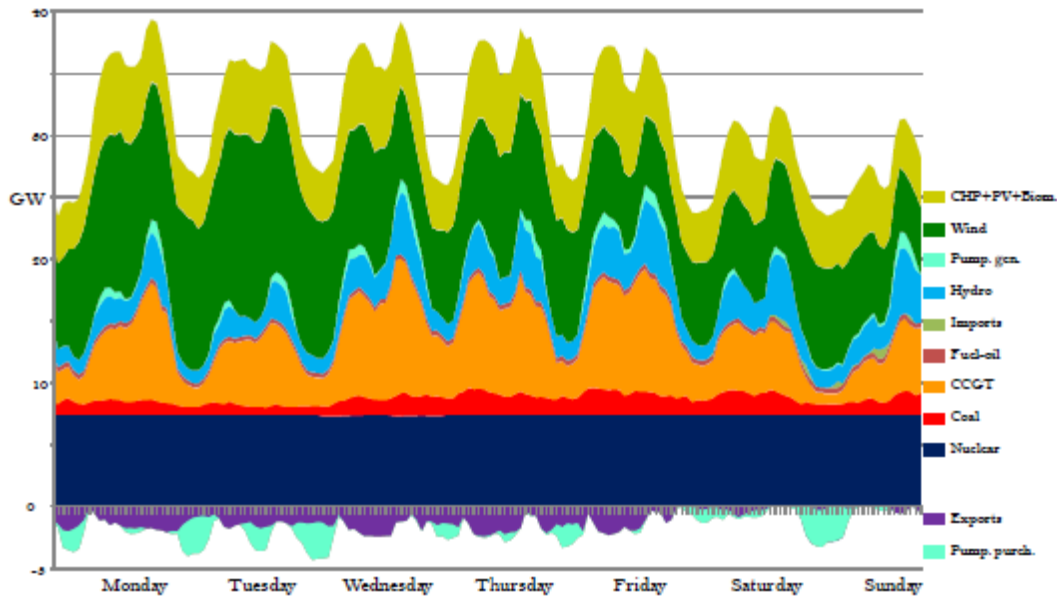


Figure 5 - Electricity supply in the Spanish system from Nov. 8th to 14th, 2010 (Source: Red Eléctrica de España)

It can be observed that generation of thermal units, particularly the load-following and peaking ones, fluctuates more with a large penetration of wind in the system. This additional "cycling"² adds to the operation and maintenance cost of thermal units.

In general, the impacts of large-scale penetration of variable generation should be considered in terms of different timeframes: seconds-to-minutes, minutes-to-hours, hours-to-days, days-to-one week and beyond (NERC 2009). Planners also must address longer time frames, sometimes up to 30 years, for both transmission and resource adequacy assessments.

- In the seconds-to-minutes timeframe, bulk power system reliability is almost entirely controlled by automatic equipment and control systems such as Automatic Generation Control (AGC) systems.
- From the minutes through one week timeframe, system operators and operational planners must be able to commit and/or dispatch needed facilities to re-balance, restore and position the bulk power system to maintain reliability through normal load variations as well as contingencies and disturbances. A contingency is an unpredictable event in the system such as the forced outage of generating units, transmission circuits, transformers and/or other equipment that might lead to the entire system instability (FERC 2013).

² Cycling refers to the startup and shutdown of thermal generation units, often done during low load periods such as overnight and on the weekends.

- For longer timeframes, power system planners must ensure that adequate transmission and generation facilities with proper characteristics are built and maintained so that operation of the system remains reliable throughout a range of operating conditions.

It has been found that wind does not change its output fast enough to be considered as a contingency event (Perez-Arriaga et al. 2012). Therefore, the largest contingency considered in the determination of reserves is not affected by wind penetration.

Also, the uncertainty and the variability of wind generation may affect the required amount of regulating (secondary) reserves, but not significantly in most cases. This is because systems already use fast response reserves to deal with load fluctuations and the effect of intermittent generation on demand for these reserves is not expected to be significant (Perez-Arriaga et al. 2012).

The largest impact of a wind intermittency is observed on the amount of load-following reserves. As a result of the errors in the prediction of wind output on the day-ahead, wind integration increases the number of generating units that must be ready-to-produce (operating reserves).

Wind will also affect the total long-term planning reserves on the system. In most systems the hours of wind peak do not coincide with load peak. This means that there should be additional dispatchable generation installed in order to meet demand in those hours. Thus, the amount of conventional capacity displaced is less than the amount of wind capacity installed and as a result, the total installed capacity in the system increases with the introduction of wind generation. In other words, all else being equal, for the same level of supply reliability a system with wind generation has more total generation capacity than a system with no wind generation.

Therefore, these effects of wind generation on reserves are expected to affect the way that power systems operate and probably impose some additional costs (at least over their integration phase).

1.2 Energy policy decision modeling tools

Given that power systems decisions are made from the very short- to the long-term, different modeling tools are used to inform decision-making in each of these timescales as shown in Figure 6 below.

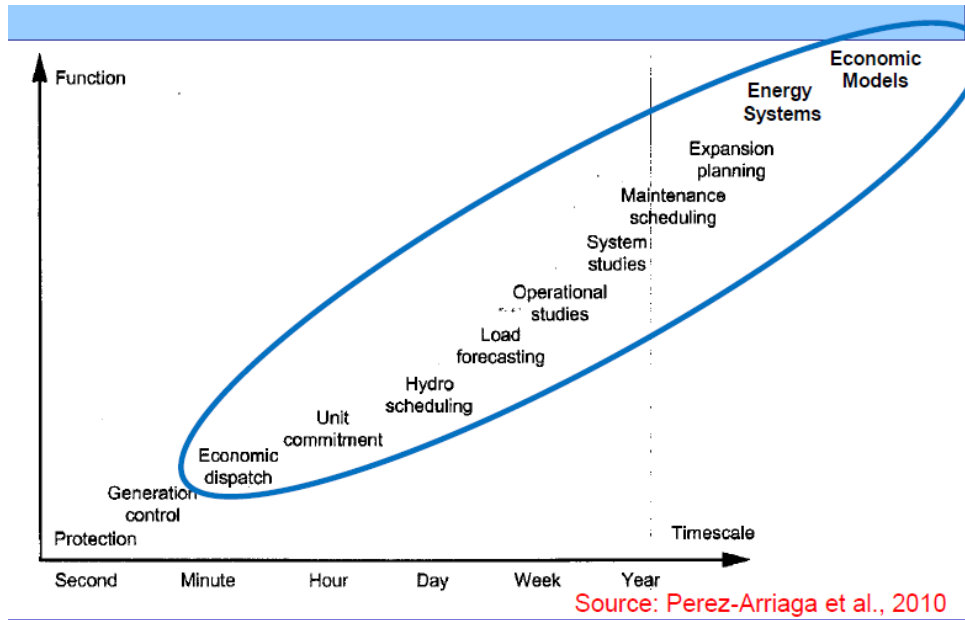


Figure 6 - Power Systems Modeling at varying scales (Source: Perez-Arriaga et. al 2010)

The models on the left part of the graph capture shorter time periods and tend to model the hourly operation of the system in detail. Moving towards the right part of the graph the models aim to capture longer periods of time and thus, sacrifice some of their detail in order not to become computationally intractable. In particular, long-term planning models often do not take the hourly load curve as an input but consider some typical demand levels within the year (base load/intermediate/peak for weekday/weekend for winter/summer etc). This practice produced acceptable results for unit dispatch, very close to reality, for traditional systems. However, when a large penetration of wind is considered, ignoring chronology of demand implied ignoring most of the effects of wind on power systems planning and operation, which are essentially caused by the hourly variations in wind generation. Therefore, it is important that information on hourly operation contained in the detailed models on the left is integrated in long-term planning models on the right.

In this thesis I attempt to integrate information coming from a unit commitment model into a computable general equilibrium (CGE) model -on the far right of the graph, indicated as "Economic models" - so that the operation of the power sector is more accurately represented within the CGE framework, and in particular, the effects of a large wind penetration in the system are adequately captured.

From the types of models that appear in Figure 6, CGE models are the only ones that capture the economy-wide interactions of power sector policies. In an era when the impacts of energy policies on the whole economy really matter to decision-makers, these models are widely used

for evaluating such policies. As Günther Oettinger, European commissioner for energy, said in an interview with The Wall Street Journal on April 10, 2013: "Today we are looking at climate protection in its entirety, taking into account that energy has to remain affordable for industries and private households. [...] Any new carbon or clean-energy targets should be more "modest and pragmatic" in light of the Continent's economic woes". Mr. Oettinger's comments indicate a shift in the EU's clean-energy strategy, with a bigger focus on keeping down costs to preserve the competitiveness of the EU's economy. In 2007, when the EU set its last binding targets for 2020 for greenhouse-gas emissions, renewable energy and efficiency, it focused almost exclusively on climate protection, Mr. Oettinger also mentioned. Therefore, the need for tools capturing the economy-wide impacts of energy and climate policies is now becoming greater.

The recently published EU Green Paper presenting "A 2030 framework for climate and energy policies" (EC 2013) also stresses the need for the 2030 framework to ensure that the EU is on track to meet longer term climate objectives, while at the same time reflecting a number of important changes that have taken place since the original framework was agreed in 2008/9.

These changes are:

- the consequences of the on-going economic crisis;
- the budgetary problems of Member States and businesses who have difficulty mobilizing funds for long term investments;
- developments on EU and global energy markets, including unconventional gas and oil, and nuclear;
- concerns of households about the affordability of energy and of businesses with respect to competitiveness;
- and the varying levels of commitment and ambition of international partners in reducing GHG emissions.

Thus, the need for EU energy and climate policies that are in tune with European economic development and do not undermine EU competitiveness, while taking into account global energy interactions makes CGE models a necessary tool for evaluating energy policies.

Given that a high penetration of renewables is expected over the following decades it is important that the power sector representation in these models captures all the relevant costs and interactions, which is what I am focusing on in this work.

1.3 Research Questions

In particular, throughout this thesis I am trying to answer the following research questions:

a) What are the characteristics of wind generation that distinguish it from conventional generation technologies and what information can one get about them by analyzing wind and load profiles in a region?

b) What are the impacts of a large penetration of intermittent wind on power system cost and operation?

c) How can these effects be integrated in a general equilibrium model of the world economy so that the true costs of energy and climate policies involving large amounts of wind are more accurately captured?

Finally, the methodology developed is applied for the case of Europe so, the last issue addressed is:

d) What will be the role of wind generation in achieving a significant Greenhouse Gas emissions reduction in Europe by 2050?

There have been several region-specific studies trying to address questions (a) and (b). Some of them focus on analyzing wind patterns - mainly using statistical methods while others use bottom-up power systems models in order to assess the impacts of wind generation within a system framework (e.g. Gross et al. 2006, Holttinen 2008). A general conclusion from these studies is that wind and load profiles as well as the effects of a large penetration of intermittent renewables on a power system largely depend on the characteristics of the particular system.

There have also been some attempts to integrate these effects in Computable General Equilibrium models that are used for analyzing the long-term economy-wide effects of energy and climate policies (question (c)). Cheng (2005) and Morris (2009) have worked on modeling the impacts of wind intermittency in the MIT Emissions Prediction and Policy Analysis (EPPA) model, by assuming that a unit of wind production at large penetrations is accompanied by the installation of a unit of energy storage or natural gas plant capacity. Chen (2012) is proposing a different approach using a CGE model for Taiwan, representing the fact that wind is easier to introduce in flexible systems with a large penetration of hydro or gas plants. Wise et al. describe the approach followed in the GCAM model, with 1-1 backup generation for wind only considered after 35% wind penetration (Wise et al. 2010).

Other approaches attempt to completely integrate short- or longer-term planning electricity models to CGE models - effectively bridging the gap in Figure 6. The goal is to have the two models exchange information in each iteration and the main barrier is the computational complexity of such a combination. However, in this way, the power sector is accurately represented and no relevant information is lost (Wing 2006, Lanz et al. 2011).

Partial equilibrium energy models - referred to as "Energy models" in Figure 6 often represent the power sector in more detail - even though the representation of intermittent renewables is still a challenge even in these models (Capros et al. 2012)- but fail to capture the economy-wide interactions of energy and climate policies.

What is currently missing from literature is an integrated approach, taking into account:

- i. wind and load profiles in a particular region
- ii. the unique characteristics of the power system and the interactions of the different generation technologies (with a bottom-up electricity model), and
- iii. the overall economic implications of an energy or climate policy affecting the power sector.

This work is an attempt to bridge this gap.

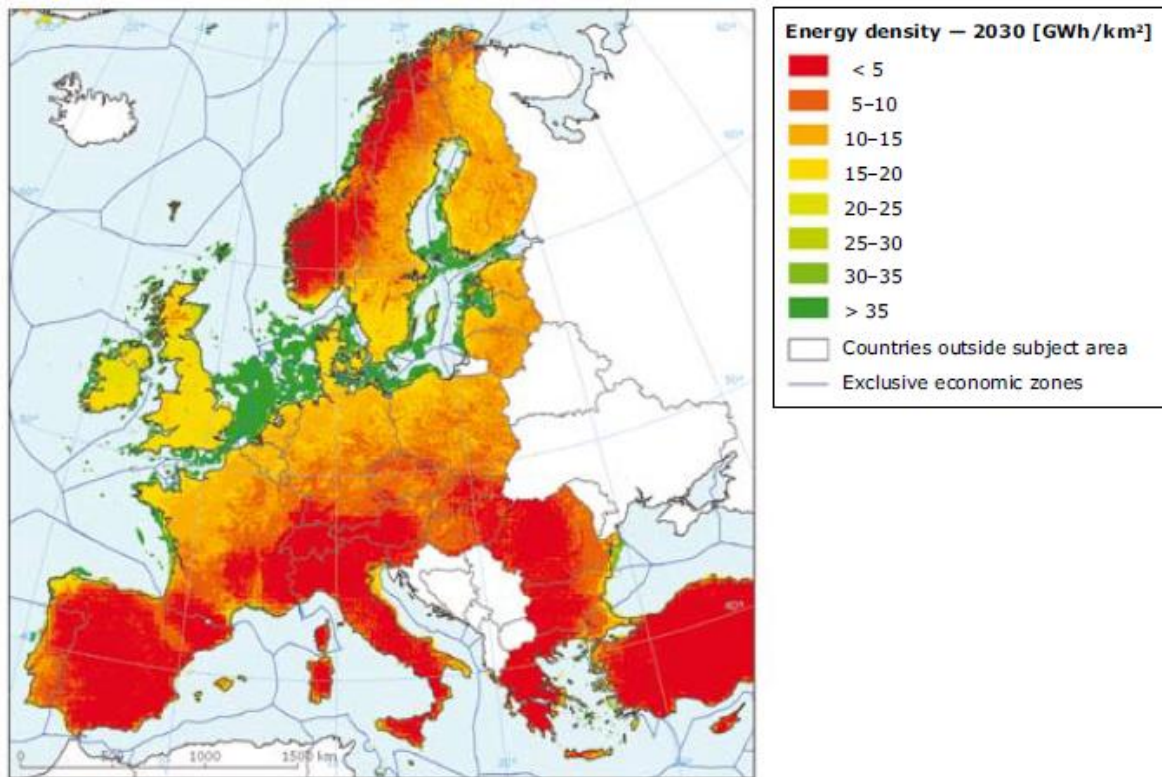
Finally, regarding question (c), the role of intermittent renewables in meeting 2050 European climate targets has been addressed by several studies, many of them supported by the European Commission (EC 2011, ECF 2010). According to these studies there is a lot of uncertainty on how the energy systems will evolve and this is why different scenarios are studied - with higher or lower penetration of renewables, with or without phase out of nuclear, with high or low CCS cost etc.

The thesis is organized as follows:

Given that wind generation is essentially determined by wind patterns in an area, in Chapter 2, wind profiles in the European region are analyzed and are compared with similar analyses that have been completed both for Europe and the U.S. In Chapter 3, the effects of a large wind penetration on the operation of power systems are explored, using a bottom-up electricity model - particularly, a single-period capacity expansion planning model with unit commitment. In Chapter 4, the MIT Emissions Prediction and Policy Analysis (EPPA) model is described with a focus on the representation of the power sector and on wind generation. Then, a new methodology is proposed for modeling wind intermittency in this model, taking into account the system "flexibility" requirements as wind penetration increases. In Chapter 5, as a case study, long-term emission reduction scenarios are modeled for Europe. The currently used approach is compared with the new approach suggested and sensitivity analyses are also completed. In Chapter 6, the outcomes of this work are summarized as well as its policy implications.

2 Analysis of Wind Variability in Europe and its Implications

Leaving aside some environmental, social and economic considerations, Europe's wind energy potential is huge. Turbine technology projections suggest that it may be equivalent to almost 20 times energy demand in 2020. As can be seen in Figure 7 below onshore wind energy potential is concentrated in North-western European areas while offshore potential can be mainly found in low-depth areas in the North Sea, the Baltic Seas and the Atlantic Ocean (EEA 2009).



Source: EEA, 2008.

Figure 7 - Distribution of wind energy density (GWh/km²) in Europe for 2030 (80m hub height onshore, 100m hub height offshore) (Source: EEA 2009)

Wind resource potential gives an estimate of the maximum amount of wind power that can theoretically be generated in a particular area. However, what is more relevant when studying the impact of a large wind penetration on a power system is the hourly profile of wind and its characteristics. Such an analysis is important for many reasons:

In a system without wind, demand varies depending on the time, day and season within the year. Demand variability, however, is predictable to a large extent. When wind is introduced the variability of wind -which is highly uncertain- is added to the variability of the demand. When

wind penetration is low, wind variability will not significantly affect the (highly predictable) variability of demand. At large penetrations, however, wind variability will dominate. So, it is important to analyze this variability.

Of course, the impact of wind on a particular power system will depend on the initial generation mix in the system - for instance, it is expected that wind will have a higher impact on a system with inflexible nuclear penetration and smaller impact on a system based on flexible gas or hydro plants. However, when modeling long-term energy scenarios the initial generation mix of a particular area is becoming uncertain as we are moving away from the present. In this case, knowing historic wind patterns can provide a worst case scenario of the impact of wind on the system neutral to the generation mix in that system. This information can be used by system planners in order to decide whether it would be reasonable to install a large amount of wind in the particular system and, if this is the case, to plan for an adequate generation mix that would minimize the effects of wind intermittency on the system.

Finally, aggregating wind time series of neighboring regions and comparing their characteristics with per region wind series can provide an indication of the value of interconnections between these regions.

It is important to note at this point that no generation source can provide power 100% of the time (because of unexpected breakdowns or maintenance) so, they are all intermittent to a certain extent. However, this characteristic is much more intense in the case of wind. Taking also into consideration that wind is expected to provide a high share of electricity demand in future power systems, I am focusing my analysis on wind variability.

Therefore, in this chapter, the characteristics of wind and load profiles for different European regions are analyzed and compared.

2.1 Analysis of Wind and Load Time Series in selected European Regions

For my analysis, I used the Modern Era Retrospective-Analysis for Research and Applications (MERRA) reanalysis data (Rienecker et al. 2011) that have a resolution of $(1/2^\circ \times 2/3^\circ)$. I used a height of 80m, which corresponds to the hub height of most wind turbines installed in the last decade (Gunturu et al. 2012). From the wind speed data I calculated statistical metrics that can be used to approximate the "size" of wind variability in each region and thus, can be an indicator of the effect of a large wind penetration in each particular system.

The initial domain considered for this study spans the whole European continent (excluding Iceland), including offshore regions, and corresponding to latitudes from 11°W to 41°E and longitudes from 34°N to 71.5°N. An analysis excluding offshore regions, was conducted as well. As a final step I disaggregated the wind data for each European country, and analyzed the similarities/differences between them.

Therefore, the analysis was conducted as follows:

1) Wind power density at each grid point ($1/2^\circ \times 2/3^\circ$) and each time step (one hour) was calculated, using the formula:

$$P = \frac{1}{2} \rho V^3 \quad (\text{Eq.1})$$

where P, ρ and V are the wind power density, density of the atmosphere and the wind speed at the point respectively.

2) Using the time series of hourly wind power density, the hourly wind power generated at each grid point was estimated, with the assumptions:

a) Turbine Size and Power Curve

A number of GE 1.5SLE wind turbines are assumed to be installed at each grid point. These turbines have a hub height of 80m and rotor diameter of 77 m. The nominal power of each one is 1.5MW at a wind speed of 14 m/s and their cut-in speed (i.e., minimum wind speed at which they generate) is 3m/s. The density of the atmosphere assumed by the technical specifications of the turbine is 1.225 kg/m^3 . The power curve of this turbine is given as a function of wind speed and is shown in Figure 8. Using the reference air density, the power curve has been converted into a function of the wind power density. At each grid point, this power curve in terms of wind power density has been used to compute the power produced by the turbine each hour.

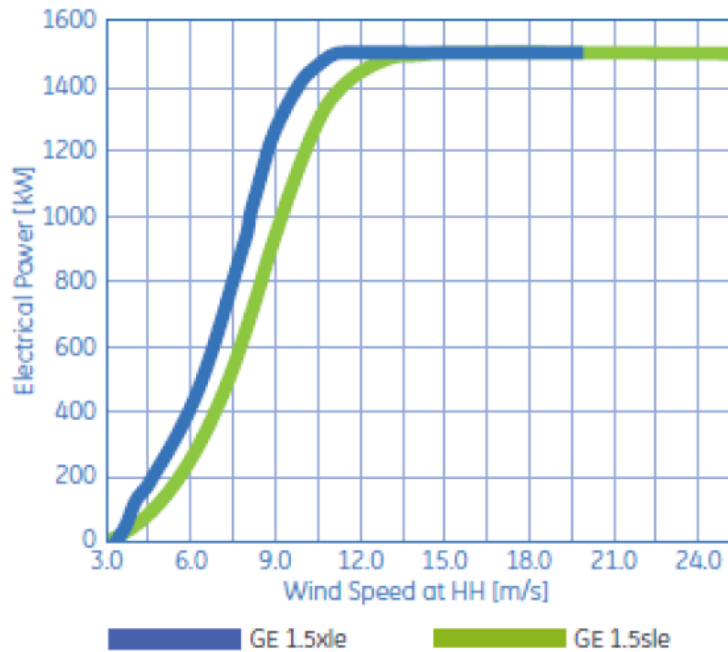


Figure 8 - Power Curve of 1.5MW GE turbines (Source: Gunturu et al. 2012)

b) Number of Turbines

Placing wind turbines 15 rotor diameters apart has been shown to be most cost effective for power generation (Meneveau et al. 2010). For GE 1.5SLE, with a rotor diameter of 77m, the separation needed is 1155m and the land area needed for each wind turbine at this optimum configuration is 0.3335 km² or about three turbines per square kilometer. Considering other land uses (forests, agriculture) and the constraints for wind farm deployment, it is assumed that 5% of each grid cell area, on average, could be reasonably anticipated to be used to deploy wind farms (EEA 2009). Each grid cell is 50 km × 66.7 km.

Next, the analysis for some typical European countries is presented as well as for the whole Europe both ignoring and including offshore regions. Italy, Spain, Germany and Sweden have been selected, which are four of the largest European countries located in the South-East, South-West, Central and Northern part of Europe respectively. Thus, they can be used to approximate wind behavior in the rest of the countries within Europe.

There are two major attributes of variable generation that notably impact the bulk power system planning and operations (NERC 2009):

- **Variability:** The output of variable generation changes according to the availability of the primary fuel (wind, sunlight and moving water) resulting in fluctuations in the plant output on all time scales.

- **Uncertainty:** The magnitude and timing of variable generation output is less predictable than for conventional generation.

Wind variability can be studied using the time series of wind. In particular, in the next paragraph I compare the hourly variability of the load before the introduction of wind with that of the net load after the introduction of wind in the system. I find that there is not a significant difference in hourly variations of load before and after the introduction of wind. This means that wind generation is not expected to pose a big challenge to the system as far as hourly variability is concerned. On the other hand, uncertainty (or unpredictability) of wind generation might have a greater effect on the system (Perez-Arriaga 2012). Errors in the prediction of wind output on the day ahead require having a significant capacity of flexible plants ready to generate, which adds to the system cost.

Hourly Variability of Wind and Load Time Series

Many studies have used standard deviation as a measure of wind variation (Holttinen, 2005a,b; Holttinen et al., 2008; Estanqueiro, 2008). In particular, Holttinen studied the use of standard deviation of the net load (load net of wind) to estimate the required power system reserves. He notes, however, that accurate estimation of the impact of wind power on power system operational reserves requires studying the system as a whole as it is the total system aggregation of the variations in all loads and generators that matters. The relative increase in system fluctuations due to wind power depends on the wind penetration level, the levels of load variability and how this is correlated with wind, as well as the initial flexibility of the system. These factors differ from region to region, which means that even for systems with the same wind penetration level there will be different wind integration costs.

According to Holttinen's approach that I am using here, the incremental increase of variability that the power system must balance when adding wind power can be estimated by considering the difference between the distribution of variations before and after wind power. As an estimate of the increase in variability, the standard deviation (σ) of the distribution can be used. Even if this is not the method by which the operating reserves are allocated in real power systems, it is fairly easy to use and produces a value that is related to the degree by which wind power increases the variability in the power system.

Assuming that L_i is the load in hour i (before the introduction of wind) and W_i the wind generation in hour i , then:

- i) I take the load time series (before the introduction of wind) and calculate variations between consecutive hours $i-1$, i :

$$\Delta L_i = L_i - L_{i-1}$$

ii) Then, I calculate the Net Load (NL) for each hour i , which is the load minus wind generation. As an example, wind was considered to be covering 25% of the demand.

iii) The variations between consecutive hours, for the Net Load time series are:

$$\Delta NL_i = NL_i - NL_{i-1}$$

The increase in variability that wind power brings to the power system can be seen when comparing the net load with the original load time series.

The following table presents the variability in the load before and after the introduction of wind. In all countries wind penetration increases load variability. An interesting observation, however, is that, if an interconnected European system is considered then the variability of the Net Load on an hourly basis remains the same as the load variability before the introduction of wind. This happens because the wind curve is much smoother on a European-wide basis. If offshore wind is also taken into account then the net load is even less variable than the initial load for 25% wind penetration.

Table 1 - Comparison of hourly variability of Load before wind and Load after wind (net load)
(Source: own calculations)

Region	Hourly variability of Load (σ_{AL})	Hourly variability of Net Load (σ_{ANL})
Spain	0.038	0.053
Germany	0.029	0.038
Italy	0.039	0.051
Norway	0.019	0.022
Europe (excl.offshore)	0.030	0.030
Europe (incl.offshore)	0.030	0.027

Some interesting insights can be drawn from this table:

a) In each individual country a 25% wind penetration leads to an increase in the hourly variability of the Net Load.

b) The level of increase is different for different countries but in all cases the change in (net) load variability after wind introduction remains small.

c) The benefit of aggregating larger regions is also obvious from the Table. If Europe had sufficient interconnections that would allow considering it as a single area then, a 25% overall wind penetration would have no effect on the hourly variations of the net load. If offshore wind is considered, as well, then wind would even lower load variations. This can be explained by the fact that the larger the area of wind aggregation, the smoother the wind profile is.

Estanqueiro (2008) also used standard deviation to study the reduction of variability of wind power when several wind farms are aggregated. In addition, several other studies have looked into the aggregation of wind turbines located in geographically diverse locations as the most suitable solution to mitigate intermittency and variability in wind power output. (Sinden, 2007; Archer and Jacobson, 2007; Degeilh and Singh, 2011; Katzenstein et al., 2010; Kempton et al., 2010).

Some additional conclusions can be drawn after determining the standard deviations of the load and net load. In particular, in power systems, operating reserves are scheduled so that the variability of the net load is covered with a specified probability. Assuming that the distribution of the hourly variations of the load and the net load is approximately normal then, about 99.7% of the data are within $\pm 3\sigma$ of the mean value of the distribution (which in both distributions is approximately zero, by default). So, the additional operating reserves required in each system could be approximated by $3(\sigma_{\Delta NL} - \sigma_{\Delta L})$. This is the difference between the approximate operating reserves that are required for a 99.7% reliability level in the case of a system with wind ($3\sigma_{\Delta NL}$) minus the approximate operating reserves that are required for a 99.7% reliability level in the case of the same system without wind ($3\sigma_{\Delta L}$).

It is important to note, however, that the goal of analyzing load and wind curves here is not to determine the exact amount of additional reserves that the system is expected to require. Instead, the goal is to get an idea of the wind and load profiles in different regions (of different size and geographical location), get a first approximation of the quality of wind and how this would correlate with load and thus, make a first comparison of the effect that a large penetration of wind would have in these different systems. Other factors are also significant when determining the amount of operating reserves that will be required. For instance, the current generation mix of the particular region. Areas that are endowed with lots of hydro resources (such as **Austria** or the Scandinavian countries) are expected to be able to integrate lots of wind with limited impact on the operating reserves required. These effects are not considered with a simple analysis of wind and load profiles.

Another useful thing to look at is the minimum wind generation over the year for different areas. This can be obtained by drawing the relevant normalized wind duration curves. These wind duration curves -similar to the load duration curves - have been created in the following way: On the x-axis, the hours of the year are sorted by decreasing wind generation. So, Hour 1 in the graph is the hour with the highest wind generation, Hour 2, the hour with the 2nd highest wind generation etc. It is obvious that these hours are not necessarily consecutive. What is nice about this graph is that, looking at the wind generation that corresponds to, let's say Hour 100, we know that there are 100 hours that have at least this much wind generation. Similarly, looking at wind generation in Hour 8760, we know that at least this amount of wind generation is provided for the whole year. Therefore, the wind duration curve provides a good estimation of the minimum amount of wind that we can rely on.

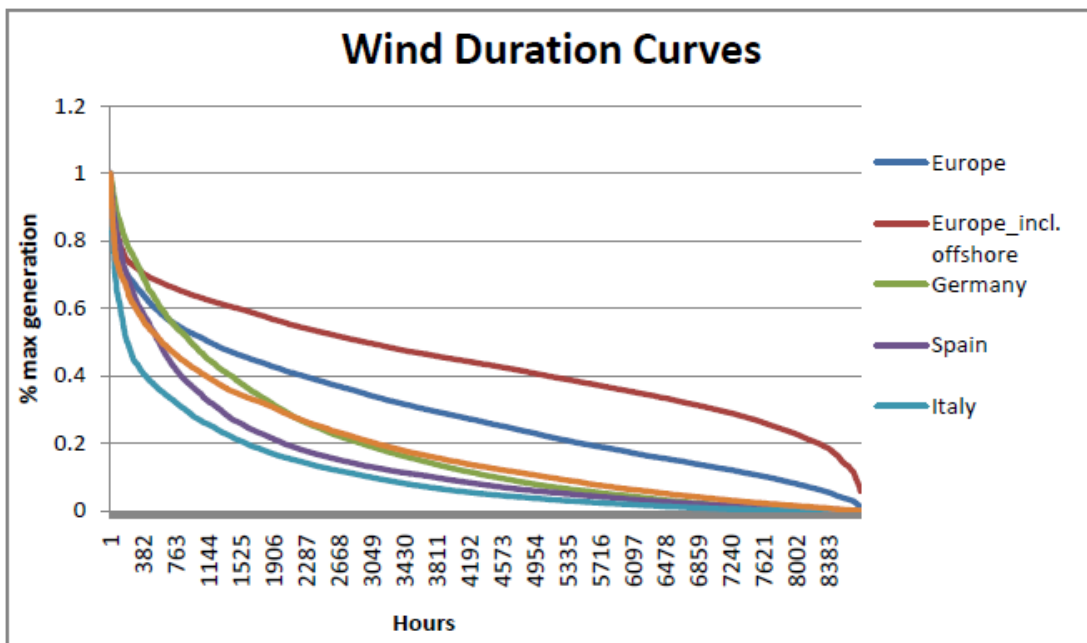


Figure 9 - Wind Duration Curves for different European Regions (Source: own calculations)

From Figure 9, it is obvious that there are hours with very low wind, particularly when a single country is considered. However, no generating unit is available 100% of the time, due to unexpected failures or maintenance, for example. So, "requiring" from wind to have the same level of reliability as a typical dispatchable unit (e.g. a Natural Gas Combined Cycle (NGCC) plant), the conclusions are different. For a 90% reliability level I am looking at the amount of wind that is available at least 10% of the time (i.e., for at least 7880 hours). Therefore, it can be concluded that, in Germany only 0.5% of wind is available for 90% of the time whereas in Europe as a whole this number amounts to 8.6%. These numbers are consistent when studying 10 years of European wind data. Again, the benefits of interconnecting the grid can be seen.

Currently, the state of interconnections in the European region lies in between the two extreme cases analyzed above - completely disconnected single countries vs. completely interconnected European grid, while the transmission grid keeps expanding. For instance, Central Europe is currently very well-interconnected. So, taking France-Germany-Denmark-The Netherlands and Switzerland as one European region, the minimum wind available 90% of the time is 2.5%.

The numbers that were derived show the minimum wind contribution to covering demand at each moment within the year. A more sophisticated way of determining the effect of a large penetration of wind is to calculate the capacity credit of wind. The capacity credit indicates how much wind contributes to peak demand, taking into account the correlation of wind and load and the characteristics of the system. It is a measure of the contribution of any new generation capacity (wind or conventional) toward securing the availability of an energy supply system. It is expressed as a percentage of the installed capacity of the new power generation source.

The capacity credit of a conventional power generation plant is influenced by the type and age of the power plant itself, the size of the balancing area, demand characteristics and the availability of the total power generation mix. A new NGCC power plant, for example, has a high capacity credit (the literature refers to levels of around 90-95%), which means that when added to a power generation system, other generation capacity can retire to the amount of 90-95% of the nameplate capacity of the CCGT plant and still retain the same system reliability (if demand stays stable). The capacity credit of wind power is lower than the capacity credit of conventional power generation techniques due to the variable nature of wind. It depends on the number of full load hours of wind, the wind penetration level, the geographical spread, timing of wind delivery relative to peak demand periods and the availability of the “rest” of the power generation mix. Increasing wind penetration level leads to a lower capacity credit for wind. For wind, the capacity credit varies in the literature from approximately 5-40%; for Northwest Europe it is usually estimated at 5-20%.

Even though the numbers vary significantly for different systems, it is generally known that the capacity credit is at its highest at low wind energy penetration levels and tails off at higher penetration levels. In particular, at low penetration levels the capacity credit of wind is approximately equal to the capacity factor of wind power during times of high load, while at higher penetration levels the capacity credit is determined with probabilistic methods (EWEA 2009). Figure 10 indicates the capacity credit values that have been estimated in different studies. The trends are similar in all cases but the absolute numbers vary, which indicates the dependence of this metric on the particular system analyzed.

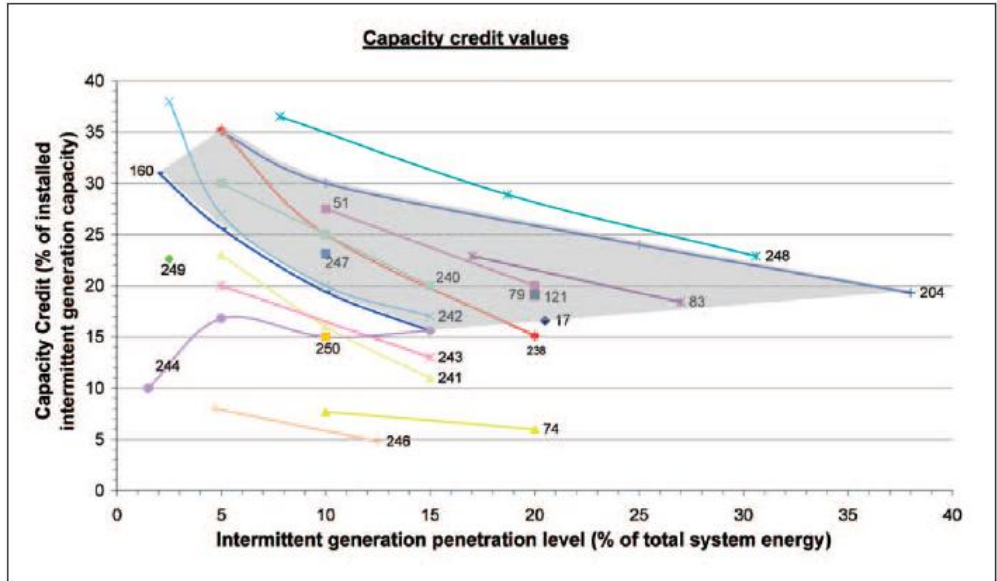


Figure 10 - Capacity credit of wind generation for different wind penetration levels (Source: Gross et al. 2006)

(Studies: Key for studies used in figure 3.3: 17(Watson 2001), 51(Mott MacDonald 2003), 74(DENA Project Steering Group 2005), 79(Dale et al 2003), 83(Ilex and Strbac 2002), 121(Giebel 2000), 160(Holt et al 1990), 204(Grubb 1991), 238(Martin and Carlin 1983), 240(Commission of the European Union 1992b), 241(Danish Energy Ministry 1983), 242(Commission of the European Union 1992d), 243(Commission of the European Union 1992a), 244(Commission of the European Union 1992g) 246(E.ON Netz 2005), 247(Sinden 2005), 248(Commission of the European Union 1992f), 249(Commission of the European Union 1992e), 250(Commission of the European Union 1992c).

It has also been found that certain factors, such as aggregation of larger areas can increase the capacity credit. For example, for the ten countries with the highest installed wind energy capacity (Germany, Spain, France, the GB, Italy, Portugal, the Netherlands, Sweden, Poland, Denmark) in 2020 according to a 12% wind penetration scenario studied in the Tradewind project (EWEA 2009), the capacity credit increases by a factor 1.5, namely from 8% (not aggregated) to 12% (aggregated). When wind power is shared between all European countries, the total capacity credit is 8%. On the other hand, when one European wind energy production system is distributed across multiple countries according to their individual load profiles, the capacity credit increases by a factor of 1.75 to reach 14%.

In order to approximate the capacity credit of wind power in Europe I am using the approach followed by IEA (IEA 2011).

For example, in the case of Germany, I create the Load Duration Curve by sorting the load for each hour of the year. I also create the Residual Load Curve by sorting the difference (Load - Wind Generation) for various wind penetration levels. The resulting curves are shown in Figure 11 below.

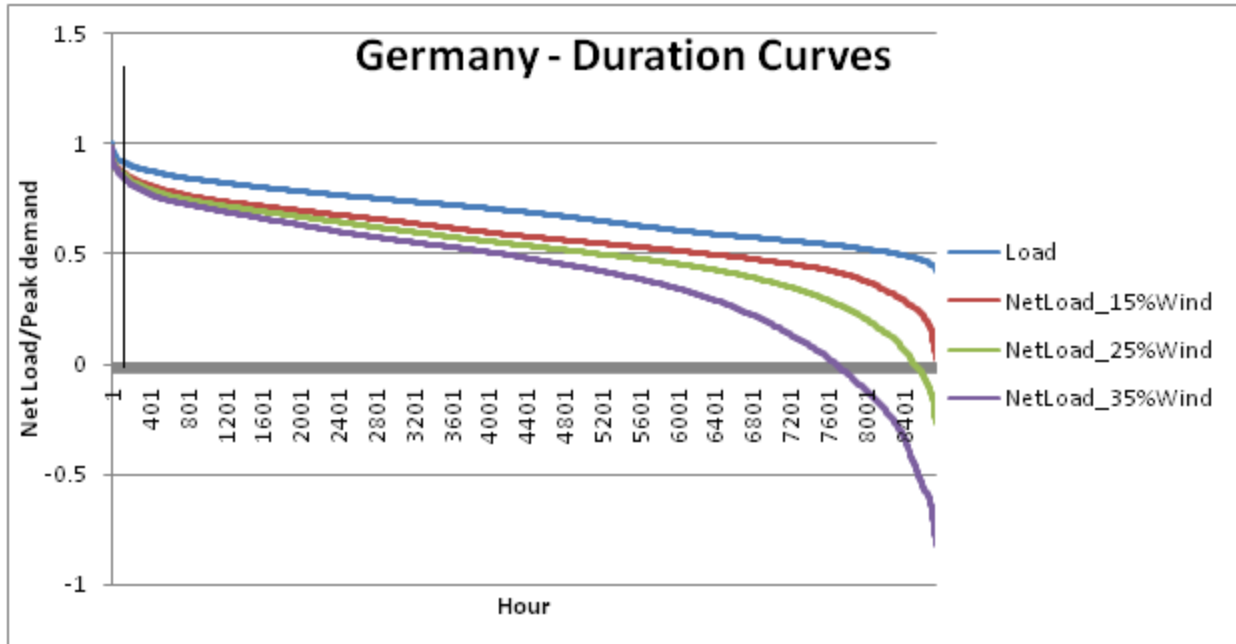


Figure 11 - Load Duration Curve and Residual Load Curves for different wind penetrations (Source: own calculations)

The peak demand is 90GW. The top curve is the system Load Duration Curve without wind while the bottom ones correspond to wind installed capacity equal to 15%, 25% and 35% of peak demand respectively. The capacity credit of wind can be approximated by finding the contribution of wind to reducing peak demand. Assuming a Loss of Load Probability of 1% this contribution is estimated by looking at the peak 100 hours in Figure 11, indicated by a vertical line. Dividing the decrease in the net load in hour 100 as a result of wind by the installed capacity of wind in the system gives an approximation of the capacity credit of wind for different penetration levels, as shown in Table 2 for Germany and for Europe as a whole (excluding offshore wind resources).

Table 2 - Capacity credit of wind for different penetrations in Germany and Europe (Source: own calculations)

Wind installed capacity (% of peak demand)	Capacity Credit (% of wind installed capacity)	
	Germany	Europe (excl. offshore)
15	7.4	14.2
25	5.3	10.4
35	4.4	8.2

Other than the capacity credit of wind there are many other metrics that can be used for studying wind intermittency and its implications. A different set of experiments has been conducted by Gunturu et al. (2012) for the U.S.

For their work they also used the MERRA reanalysis data (Rienecker et al., 2011). They characterized wind patterns over 30 years (from 1979 to 2009) using descriptive statistics of wind power, such as the mean Wind Power Density, the Coefficient of Variation of wind power, and the Wind Episode Lengths. They looked at Intermittency metrics, mainly focusing on the spatial and temporal relationship between the wind resource at different "grid points". An important conclusion from their experiments is that the west coast region of the U.S. has sufficient spatial inhomogeneity of wind resource intermittency. However, in the central U.S. which is very rich in wind resource, homogeneous intermittency patterns are observed.

They also calculated hourly capacity factors and power generation at each grid point for seven different Independent System Operator (ISO) areas. Hourly capacity factors were defined as the ratio of the wind energy produced in a particular hour over the total wind installed capacity. They found that aggregation of wind power in each ISO region mitigated intermittency to some extent, reducing the fraction of time for which the power is less than 5%. However, in spite of the improvement due to aggregation, each region has considerable fraction of time for which the capacity factor is less than 5%. Table 3 shows their capacity factor statistics for different ISO regions for 31 years of data:

Table 3 - Statistics of intermittency in different RTOs in the U.S. (Source: Gunturu et al. 2012)

ISO	Critical hours (%)		Level crossing rate		CoV of AP ¹	Median ACF ²
	< 5%	< 10%	5% level	10% level		
CalISO	53	70	298	263	1.26	0.04
ERCOT	28	45	239	262	1.02	0.12
MISO	15	30	150	212	0.82	0.18
NEISO	56	71	198	161	1.51	0.03
NYISO	56	70	198	160	1.52	0.04
PJM	45	63	213	189	1.22	0.06
SWPP	17	31	180	238	0.85	0.18

¹ AP: Aggregated power

² ACF: Aggregated capacity factor

The aggregated capacity factor is defined as the ratio of the total produced power in the region (i.e., sum of the power produced in all the cells that correspond to the region) to the total name plate capacity in the region.

The critical hours are the percentage of hours for which the aggregated capacity factor in the particular region is less than 5% or 10%. The level crossing rate shows the number of times that wind generation crosses this hourly factor of 5% or 10%.

CoV of AP is the Coefficient of Variation of the Aggregated Power. The Coefficient of Variation is a normalized measure of the dispersion of a probability distribution. It is defined as the ratio of the standard deviation (σ) to the mean (μ):

$$\text{CoV} = \frac{\sigma}{\mu} \quad (\text{Eq.2})$$

For two regions with the same mean power density, the one with a lower standard deviation will have lower CoV and is preferable (i.e. less variable power quality). Similarly, for two regions with the same standard deviation, the one with greater mean power density is preferable and this has lower CoV. Given the impact of variability in wind power on the electric grid and the economics of power generation and distribution, it is desirable to lay wind farms in regions of low CoV of wind power.

The last column presents the Median Aggregated Capacity Factor, which is a measure similar to the Mean, but robust to outliers in the wind time series.

In Table 4 below, the CoV for Europe has been calculated using the European data:

Table 4 - Coefficient of Variation (CoV) for selected European regions (Source: own calculations)

Region	CoV of AP
Spain	1.24
Germany	1.13
Italy	1.31
Norway	0.95
Europe (excl.offshore)	0.61
Europe (incl.offshore)	0.36

The Coefficient of Variation (CoV) of the aggregate power in single European countries is comparable to that in U.S. ISO regions as found by Gunturu et al. What is noteworthy, however,

is the very low CoV of 0.61 that is observed when Europe is studied as one area. This shows the benefits of aggregating wind farms throughout the European region. When offshore wind is taken into account the CoV gets even smaller. It should be noted here, though, that the numbers for offshore wind might be somewhat optimistic. Some of the areas considered are further away from the shore and, in reality, installing wind parks in these areas might not be economical, besides the better quality of wind.

3 Impact of a Large Wind Penetration on Power Systems Operation

Intermittency is the main characteristic of wind that makes its large-scale integration challenging for power systems costs and operation. There are various ways to mitigate this intermittency (IEA 2005):

3.1 Ways of mitigating wind intermittency

Power plants for providing operational reserves and backup capacity:

In today's systems operational reserves and backup capacity are mainly offered by power plants of various types, such as, for example, open-cycle gas turbines (OCGT) or coal plants. In systems with a large amount of wind additional reserves and backup capacity will be needed to make up for wind intermittency, provided by new or existing plants. Flexible plants with relatively short response times are expected to be needed for this purpose given the uncertainty in wind generation. Overall, in terms of commercial availability, cost competitiveness and ease of system integration, power plants are the state of the art for providing the necessary ancillary services for intermittent wind generation and additional backup capacity in most countries and are certainly the most tried and time-tested from the point of view of the System Operator. In this work this is the wind intermittency mitigation option that has been considered and a further analysis is presented later on.

Storage:

Hydro storage facilities, whether in the form of pumped-hydro or hydro reservoirs, have played a key role in many countries in providing grid balancing services. Their advantages are the potential for large-scale electricity storage (>1000MW capacity, depending on location), fast response times and relatively low operating costs. However, beyond hydro storage, there has been very little commercially available storage technology that operates on today's electricity grids. The main reason is that large-scale grid integration replaces to a certain extent the function of storage and that other storage technologies are not cost competitive yet. Storage systems within the grid have to compete against other technologies for the operational reserve services they could provide, and there is no a priori advantage to storage systems over generators for example. One fundamental problem with storage is that when energy is converted from one type to another, conversion losses and thus inefficiencies are inevitably incurred. This is true for batteries and hydrogen fuel cells (where electrical energy is converted to chemical energy storage) and flywheels (where electrical energy is converted to kinetic energy).

Certain storage systems such as flywheels and certain battery types could become viable to provide specific support services for renewables in the frame of bridging very short-term output fluctuations (less than one minute). Depending on available locations another viable form of

storage is compressed air, which is stored in geologic structures under the ground and released when necessary. In the long-run, it is speculated whether hydrogen storage might become a viable option on different scales, however, currently high costs and relatively poor round-trip efficiency is preventing wider market penetration.

Overall, in the absence of major technological and cost breakthroughs, storage in mature large scale power systems will only play a minor role in the short term, apart from hydro- and compressed air storage. Besides, technologies for bridging short-term power fluctuations such as flywheels or batteries may only gain importance at higher than current wind penetration levels. As renewables penetration in the markets increases, the need for operational reserves becomes more important and could act as an incentive for introducing storage systems. Also, the full pricing of emissions of conventional reserve providing backup capacity would improve the relative economics of storage as an alternative.

Interconnections:

Interconnections are a way to mitigate wind intermittency as they enable different regions to share their operating reserves and backup capacity resources. Large volumes of intermittent generation would be integrated much more easily in existing power systems with integration and coordination of balancing areas (Perez-Arriaga 2012). In addition, interconnections lead to geographical aggregation of wind resources, which can smooth out the overall wind generation curve. Aggregation of wind turbines located in geographically diverse locations has been studied extensively and is being looked upon as one of the most suitable solutions to mitigate intermittency and variability in wind power output. Several studies have researched the viability of this option (Sinden, 2007; Archer and Jacobson, 2007; Degeilh and Singh, 2011; Katzenstein et al., 2010; Kempton et al., 2010). A recent study by Katzenstein et al. (2010) showed that a substantial reduction in the small scale variability of wind power can be achieved by interconnecting wind plants. The most important assumption in choosing this mitigation option is that the wind power from the different aggregated farms is anti-correlated. Many researchers studied the presence of such anti-correlation (Apt, 2007; Archer and Jacobson, 2007; Kempton et al., 2010; Katzenstein et al., 2010; Degeilh and Singh, 2011). The positive effects of aggregation in Europe were shown in Table 2 of the previous chapter.

Demand Response:

According to Federal Energy Regulatory Commission, Demand Response (DR) is defined as: “Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.” DR makes the demand curve for electricity

more elastic and thus sensitive to price changes which will reduce the need for reserves in an electricity market *ceteris paribus*. Theoretically, DR holds a huge potential that still has to be demonstrated. This includes applications that have long been used such as "interruptibility" contracts with large industrial consumers or more recent endeavors such as aggregation of medium and small-size consumers by third parties. In practice, contributions from DR in many countries have so far been relatively small with the exception of certain markets, such as PJM in the US. It is however unclear, whether this is due to electricity users' marginal valuation of electricity being too high to stay on-line even at high prices, or whether there are transaction costs or informational barriers to access such a market.

These intermittency mitigation options have a certain cost (e.g. cost of building transmission lines or cost of building additional plants for system backup) or provided services that have a certain cost (e.g. provision of operating reserves). To the extent that these costs are caused exclusively due to the presence of wind, they could be considered as the wind system integration costs. However, the constant interactions between technologies in a power system make it hard to isolate the impact of wind.

3.2 Costs of Wind power integration - Literature Review

Many efforts have been made to quantify the additional system costs that wind power might impose on electricity systems. According to IEA (IEA 2005) assessing the added costs of integrating renewables into electricity grids involves four main parameters:

Balancing/operational reserves, capacity reserves and extension of transmission and distribution lines. Overall, grid operators estimate that the need for additional operating reserve is likely to be limited relative to the other two items. As wind power expands, the issues of additional capacity reserve and new transmission and distribution lines will grow in importance. Some studies aim to quantify all of the above-listed system integration costs, others focus specifically on the operating and capacity reserves.

Balancing/operational reserves: Even though power plants are committed to generate in advance, adjustments are needed in real time (or close to real time) to ensure that demand and supply balance at each instant. The system operator balances the system by purchasing services from generators or adjustable loads (balancing or operational reserves). Intermittent generation adds to the balancing costs by requiring the provision of additional reserves. Holttinen et al. (2011), Gross et al. (2006) and Hirth (2012a) compile balancing cost estimates from various studies at different penetration levels. Even though different studies are hard to compare and there is some variance in the results, a characteristic relation can be found. In particular, Ueckerdt et al. (2013) have parameterized balancing costs from these studies at about 2 to 4 €/MWh when increasing the wind share from 5% to 30%.

Capacity Margin: To maintain reliability of supplies in an electricity system the installed generation must exceed peak demand by a "system margin". This margin is needed to cope with unavailability of installed generation and fluctuations in electricity demand. Conventional plants – coal, gas, nuclear – cannot be completely relied upon to generate electricity at times of peak demand as there is, approximately, a one-in-ten chance that unexpected failures (or “forced outages”) in power plants or transmission networks will cause any individual conventional generating unit not to be available to generate power. Even with a system margin, there is no absolute guarantee in any electricity system that all demands can be met at all times. Intermittent generation increases the size of the system margin required to maintain a given level of reliability. This is because the variability in output of intermittent generators means they are less likely to be generating at full power at times of peak demand. Intermittent generators can make a contribution to system reliability, provided there is some probability of output during peak periods. They may be generating power when conventional stations experience forced outages and their output may be independent of fluctuations in energy demand. These factors can be taken into account when the relationship between system margin and reliability is calculated using statistical principles. The amount by which the system margin must rise in order to maintain reliability has been described in some studies as “standby capacity”, “back-up capacity” or the “system reserves”.

The additional capacity to maintain reliability entails costs over and above the direct cost of generating electricity from intermittent sources. There has been some controversy over how to estimate the costs associated with the additional thermal capacity required to maintain reliability. In part this reflects the fact that under current market arrangements there is no single body with responsibility to purchase system margin. This is one reason why costs are less transparent than they are for system balancing services.

Some studies have assessed the costs of the capacity required to maintain reliability based on assumptions about the nature of plant providing ‘system reserves’. Others have assessed only the change in the total costs of the electricity system as a whole. There is broad agreement between both approaches on the total change to system costs. For example, the cost to maintain system reliability has been found to be within the range of £3 - £5/MWh under British conditions (Gross et al. 2006). This number has been estimated based on the difference between the contribution to reliability made by an intermittent generation plant and the contribution to reliability made by a conventional generation plant that provides the same amount of energy when operated at maximum utilization.

Other than looking at costs, impacts can also be expressed in MW terms; again for the British system, additional conventional capacity to maintain system reliability during demand peaks

amounts to around 15% to 22% of installed intermittent capacity. This assumes around 20% of electricity is supplied by well dispersed wind power (Gross et al. 2006).

Transmission: Regarding grid-related costs of integrating variable renewables, Holttinen et al. (2011) give an overview for grid reinforcement costs mainly due to added wind power. At wind shares of 15-20% these costs are about 100 €/kW (~3.75 €/MWh). For Ireland the costs rise to 200 €/kW (~7.5 €/MWh) at 40% wind penetration (All Island Grid Study 2008). For Germany DENA (2010) calculates annual transmission-related grid costs of € 1 bn to integrate 39% renewable energy of which 70% is wind and solar generation. This corresponds to 7.5 €/MWh of intermittent renewables.

A general conclusion that can be drawn from these studies is that precise numbers are country-specific and there is no one cost figure that is universally applicable. Even if the systems were similar, however, confusion might arise as different studies often use the same terms in a different way. As noted in Gross et al.(2006), some studies of the ‘cost of intermittency’ only quantify the cost of additional system balancing –the capacity to maintain reliability may be neglected, or not directly addressed. This may give rise to a ‘reserve cost’ estimate that understates the full cost of intermittency. In other studies, however, the term ‘reserves’ is used to refer to both capacity provision to maintain reliability and short term reserves, which leads to cost estimates considerably larger than those directly attributable to the only reserve services actually purchased by the system operator. It is not always clear which approach is used in each study so, comparisons should be made carefully.

In this work I am focusing on the first option described for mitigating wind intermittency, i.e., using power plants for providing operating reserves and backup capacity to the system.

I am not attempting to find a figure representing the cost of wind intermittency. Instead, I approach this cost by determining how the capacity of thermal plants and the energy produced by them will be affected by the introduction of a large amount of wind generation in the system. The procedure followed is explained in detail in Section 3.3.1. I am using a bottom-up electricity model for simulating the system and then, integrate the information obtained to a top-down CGE model. The aim is to enable the CGE model to better capture the impacts of a large penetration of wind in the system and the additional system costs incurred.

It should be stated here that, even though only some of the wind intermittency mitigation options have been described above and just one of them is considered in the modeling that follows, it is expected that at very high wind penetrations the least-cost solution for dealing with wind intermittency will come from combining all the available options (i.e., flexible power plants and storage and sufficient interconnections and demand response etc). Also, the resultant mix of options is likely to be different between different national grids according to the available

resources but also to political factors and public perception (particularly relevant in the case of interconnections or demand response).

3.3 Insights from Bottom-up Electricity Model Simulations

In this work a bottom-up electricity model was used in order to determine the effects of a large penetration of wind generation in power systems.

The model used is a single-period capacity expansion planning model with unit commitment formulated as a linear programming problem. Its solution gives the cost-optimal mix of technologies that meet demand requirements in a particular year, subject to constraints such as: Electric load balance per hour, Downward and Upward operating reserves requirements, Start-up and shut-down constraints, Maximum and minimum generation constraints and Long-term capacity requirements.

The model is an adaptation of the MARGEN model (Meseguer et al. 1995) with some modifications, including the hourly representation of load and wind. This addition is really important for my purpose as it makes the model suitable for studying large wind penetrations. Commonly, electricity models of this category consider some typical load segments within the year (energy and time blocks) in order to minimize computational complexity. However, by making this simplification the effect of wind on the power system that depends on the hourly correlation of wind and load time series is not accurately captured. The model used overcomes this problem by considering the hourly wind and load curves within the year.

The objective function of the model is a minimization of the Total annualized cost of producing electricity in a region which, for the single period version used here, has the following cost components:

$$\begin{aligned} \min TotalCost(r) = & \left(\sum_n IC_{r,n} \cdot c_{r,n}^{fix} \right) + \left(\sum_{h,n} G_{h,r,n} \cdot (c_{r,n}^{fuel} + c_{r,n}^{vom} + c_{r,n}^{CO2}) \right) + \\ & \left(\sum_{d,h \in d,n} (CP_{d,r,n} - G_{h,r,n}) \cdot c_{r,n}^{vom} \right) + \left(\sum_{d,n} SU_{d,r,n} \cdot c_{r,n}^{su} \right) + \left(\sum_h NSE_{h,r} \cdot c^{nse} \right) + \left(\sum_h S_{h,r} \cdot c^{surplus} \right), \quad (Eq.3) \end{aligned}$$

where:

Indices:

- r = region
- n = technology
- d = day
- h = hour

Variables:

IC = installed capacity of technology n, in region r (in GW)

G = generated power of technology n, in hour h, region r (in GWh)

CP = connected power of technology n, in day d, region r (in GW/day)

SU = connected power of technology n, started up from day d-1 to day d, in region r (in GW/day)

NSE = non-served energy in hour h, region r (in GWh)

S = energy surplus in hour h, region r (in GWh)

Parameters:

c^{fix} = annualized fixed cost of technology n, in region r

c^{fuel} = fuel cost (=fuel price x heat rate of technology n)

c^{vom} = variable O&M cost of technology n, in region r

c^{co2} = cost of CO2 (= price of CO2 emissions x emission factor of technology n)

c^{su} = start-up cost of technology n, in region r

c^{nse} = cost of non-served energy

So, in brief:

TotalCost = CapitalCost + VariableCost + OpResCost + StartUpCost + NSECost + SurplusCost

OpResCost is the cost of spinning operating reserves given by:

$$\text{OpResCost} = \sum_n \{(\text{ConnectedPower} - \text{GOut}) * \text{VarO\&MCost}\}.$$
 This is the difference between

the total capacity that is synchronized with the system each hour minus the amount of energy that is generated (i.e., the amount of available synchronized capacity that is ready to generate if needed), multiplied by the Variable Operation and Maintenance costs.

NSECost is the cost of Non-Served Energy in the system. A fictitious generator is used to model non-served energy, without investment or connection costs, but with a very high variable cost $c^{\text{NSE}} = 1000\$/\text{kWh}$.

Surplus cost is the cost of having energy produced in excess (surplus) in the system. It is used in order to have a reasonable economic operation of the system, especially under a high wind penetration scenario.

Various technologies are represented in the model. For my purposes I used the following ones: Natural gas combustion turbine, Combined cycle gas turbine, Combined cycle gas turbine with carbon capture and sequestration (CCS), Conventional pulverized coal steam plant, Advanced supercritical coal steam plant, Integrated gasification combined cycle (IGCC) coal, IGCC with carbon capture and sequestration (CCS), Gas steam turbine, Nuclear plant, Conventional pulverized coal steam plant (with SO2 scrubber and biomass co-firing).

When a large wind penetration is considered in different power systems that have different wind and load patterns and different initial generation mixes the outcomes are expected to be different. Here, I attempt to understand how the impacts of wind generation are changing when these underlying factors (wind resource, wind/load profiles, generation mix) differ and to find some rules that could describe this change. In particular:

Wind resource: It has been shown by Gunturu et al. (2012) for the U.S. that the regions that have less wind resource (California, New England, New York and PJM) have longer durations of no power whereas the regions in the central U.S. that have higher resource (MISO, ERCOT and SWPP) have no power for shorter durations (see also Table 3). Therefore, integrating a large amount of wind generation in areas with relatively lower wind resource is expected to be more challenging.

Hourly wind and load profile: The more the load profile is correlated to the wind profile (common peak and valley hours) the easier the integration of wind power is expected to be. In particular, if wind generation tends to peak over hours of peak demand, the capacity credit of wind will be higher. Thus, the additional system backup capacity required in case of a large wind penetration will tend to be lower.

Initial generation mix: A very important source of flexibility in the system is the spare capacity of already existing flexible power plants. Particularly, in systems with large wind penetration the rest of the technologies in the mix should be able to vary their production fast enough - following wind fluctuations - in order to meet demand. Coal plants and current nuclear plants were not designed specifically for this flexible operation, but were instead intended to provide steady base load generation. Natural gas plants, on the other hand, have been built, in part, with flexibility in mind in order to respond to the daily variations in load. Table 5 compares the flexibility of gas plants with that of other plants (MIT 2012).

Therefore, these flexible gas plants will play an increasingly important role in systems with large wind penetration levels. In a system with already a lot of flexible capacity installed it is expected that wind will be integrated without significant additional costs, as opposed to a system which initially has a lot of inflexible generation installed. For instance, the "New England Wind Integration Study" (NEWIS) has revealed that the ISO-NE system currently has adequate resources to accommodate up to 24% of annual energy penetration of wind generation by 2020 (GE Energy 2010).

Table 5 - Comparison of the flexibility of gas plants with other energy plants (Source: IEA 2012)

	CCGT	OCGT	Coal (conventional)	Hydro	Nuclear
Start-up time (hot start)	40 to 60 minutes	<20 minutes	1 to 6 hours	1 to 10 minutes	13 to 24 hours
Ramp rate	5% to 10% per minute	20% to 30% per minute	1% to 5% per minute	20% to 100% per minute	1% to 5% per minute
Time from zero to full load	1 to 2 hours	<1 hour	2 to 6 hours	<10 minutes	15 to 24 hours
Minimum stable load factor	25%	25%	30% to 40%	15% to 40%	30% to 50%

Source: IEA, 2012; Siemens, 2011; and VGB, 2011; and expert opinion.

3.3.1 Simulation Methodology and Results

Using the bottom-up electricity model described as a tool, there are various ways in which one can approach the problem of determining the impact of a large wind penetration on a power system. A simple approach would be to just take an existing system that can already meet demand without wind (well-adapted system), add wind to it and observe the changes in the generation mix. However, this approach would underestimate the effect of wind on the system. Wind in this case will not be required to provide any firm capacity. Instead, it will only be adding extra capacity to a system that already has enough installed capacity to meet demand and ensure reliability.

A better approach that has been used in this work is the following:

- Start by an existing, well-adapted system.
- Increase system demand (D) by a significant amount ΔD .
- "Require" this additional demand to be met by wind generation (i.e., "require" an amount of energy equal to ΔD to be produced by wind), while maintaining the same level of reliability. This reliability level is a hard requirement imposed by relevant model constraints and is maintained by adding, if necessary, generation of other technologies.
- Analyze the resulting changes in capacity and energy of all other technologies in the system (thermal technologies in my case) that need to "come together" with the amount of wind energy imposed in order to meet the increment in demand (ΔD).
- Thus, find the additional thermal capacity and energy required per MW of wind installed and MWh of wind generated in order to "help" wind technology to meet additional demand in the system.

For the analysis several U.S. power systems were simulated. The nonexistence of a publicly available model already calibrated for Europe and the difficulty in finding all the detailed data needed (e.g. initial generation mix in each country and particular technologies used) in order to calibrate our bottom-up model (already calibrated for the U.S.) within the available timeframe were the main reasons for working with U.S. systems.

However, the results obtained can be applied to Europe, as well. Power systems in different U.S. regions have very different characteristics and this allows the effects of different factors - wind resource, wind and load profiles, flexibility of the initial generation mix - to be captured. For instance, the New England system has a relatively low wind quality (Gunturu et al., 2012) but a flexible initial mix. On the other end, the North-Central system (including Missouri, North Dakota, South Dakota, Nebraska, Kansas, Minnesota, Iowa) has much better quality of wind but an inflexible initial mix, without hydro generation and mainly consisting of coal plants. In fact, these two systems (i.e., New England and North-Central) presented the two extremes among a number of U.S. systems that were simulated (including Texas, California, North-East and South-Central regions). Therefore, because of the variety of wind resource levels, of generation mixes and wind and load profiles found in U.S. systems, the range of the obtained results will be applicable to systems in other developed countries with similar load patterns and technological options, such as the European systems.

Based on the results from the bottom-up electricity model runs, certain conclusions can be drawn regarding the effect of a large penetration of wind in a system:

- In order to meet an increment in demand with wind generation additional thermal capacity needs to be installed in the system.
- In all cases this additional capacity comes from natural gas plants.
- Two types of plants are installed: peaking Gas Turbines and load-following Combined Cycle Gas plants (NGCC). The reason for this is because natural gas plants are currently more flexible - in the sense that they have fast ramping³ times, short startup times and are more economical (have lower combined capital and operational expenses - CAPEX and OPEX -for short- and mid-utilization factors).
- For different wind penetration levels the resulting mix is different. A different amount of Gas Turbines and NGCC plants are installed and these plants are operating at different capacity factors. In particular:
 - For smaller wind penetrations peaking Gas Turbines are mainly installed. As wind penetration grows, fewer peaking units are installed and, gradually, NGCC plants take their place.

³ Ramping refers to changes in the output of a thermal generation unit, often done to balance the electricity supply with the electricity demand.

- As wind penetration increases the capacity factor of the additional peaking gas turbines installed decreases and the capacity factor of the additional NGCC plants installed increases.

Table 6 shows the additional thermal capacity required (in kW per additional kW of wind installed) and the capacity factors of these additional thermal plants - both for Gas Turbines and for NGCC plants. The two regions that had the most "extreme" results are presented - New England and the North-Central region. The numbers refer to each wind penetration increment. For instance, for North-Central, moving from a 20% to a 30% (of total energy) wind penetration, each kW of wind will "need" to be accompanied by 0.33kW of NGCC installed.

Table 6 - Additional thermal capacity per kW of wind capacity in the New England and North Central systems and capacity factors of these additional thermal plants (Source: own calculations).

New England							
Wind Penetration		10%	20%	30%	40%		
Gas Turbines	Additional capacity	0.68	0.58	0.24	0.14		
	Capacity factor of additional capacity	0.05	0.08	0.03	0.01		
NGCC	Additional capacity	0	0.12	0.57	0.54		
	Capacity factor of additional capacity	0	0.29	0.58	0.28		
North-Central							
Wind Penetration		10%	20%	30%	40%	50%	60%
Gas Turbines	Additional capacity	0.43	0.37	0.27	0.08	0.07	0.01
	Capacity factor of additional capacity	0.07	0.05	0.03	0	0	0
NGCC	Additional capacity	0	0.18	0.33	0.37	0.48	0.54
	Capacity factor of additional capacity	0	0.12	0.16	0.17	0.23	0.29

According to a conservative approach that is used in some studies, for large wind penetrations a 1-for-1 backup capacity should be used for wind as there might be periods of time when wind is not blowing in large areas. This can happen theoretically in periods of anti-cyclones but existing data - at least for Europe - do not provide evidence that this has happened so far. In particular, in the 10 years studied for Europe there has not been an indication of long periods of very low wind in extended areas. There is not such evidence in literature either. Sinden (2002) found that the longest continuous time of calm weather in a 21-year hourly wind data set from 13 different locations in England and Wales was 11 hours. For the Scandinavian countries, 3-year data (2000-2002) showed that the longest duration of calm (production below 1 % of capacity) for Denmark was 58 hours in 2002 and 35 hours in 2000. For Finland and Sweden it was 19 hours and for Norway 9 hours. For the combined wind power production of these four countries, there were no totally calm periods in the data (Nørgård et. al. 2004).

In any case, statistically these low-frequency, high-impact 'outlier events' are at the edge of the probability distributions. Building additional capacity in order to meet demand during these very rarely occurring events will most probably not be the most cost-effective solution. Instead there are other ways in which these events could be dealt with. Implementing Demand Response would be a solution or even choosing not to meet demand for these few hours. In general, if the cost of meeting demand in these very few hours is higher than the value that consumers - on aggregate - place on having electricity over these hours then, it would be acceptable to have some Non-Served Energy over these hours. So, the 1-1 backup consideration - in whichever models this rule is adopted - is a conservative approach that adds to the system cost when wind is introduced.

So far, the impact of wind penetration on the capacity mix was discussed but the energy mix will be affected, as well. In the presence of an increasing amount of wind in the system generation from coal plants is decreasing while generation from natural gas plants (as a total) is increasing. Disaggregating the generation patterns of the different types of gas plants, as we move to larger wind penetrations generation from peaking units is decreasing while generation from NGCC plants is constantly increasing. This result can be explained logically:

- At smaller wind penetrations additional peaking plants are installed in the system in order to deal with relatively small wind fluctuations. At this point, it is not economical to install NGCC plants that have higher capital costs and have them operate only for a very limited amount of time. However, as wind penetration gets larger fluctuations in the net load also become larger and flexible thermal plants need to operate more. So, it is more economical to install NGCC plants rather than peaking units in the system. As the capacity of NGCC plants increases in the system compared to GTs, these plants tend to "substitute"

generation from GTs whenever possible as their marginal cost of generation is lower than that of GTs.

Finally, generation from nuclear plants is generally not affected as more wind is added to the system.

An interesting thing to explore is what exactly is causing this additional capacity of thermal plants to be installed. A way to approach this is by looking at the model constraints that involve thermal capacity and finding which of these constraints are binding. These binding constraints will be "responsible" for the additional capacity installed. Written in a simple form, the main relevant constraints are the following:

a) Downward Operating Reserves:

$$\sum_n (G_{h,r,n} - CP_{d,r,n} * p_{min,r,n}) \geq 0.01 * p_{HrLoad}_{h,r} + 0.2 * p_{Maxwind}_{d,r}; \quad (Eq.4)$$

b) Upward Operating Reserves:

$$\sum_n (CP_{d,r,n} - G_{h,r,n}) \geq 0.5 + 0.01 * p_{HrLoad}_{h,r} + 0.2 * p_{Maxwind}_{d,r}; \quad (Eq.5)$$

c) Long-term Capacity Margin:

$$\sum_n IC_{r,n} \geq (1 + p_{Reserve_r}) * p_{NetLoad}_{h,r}; \quad (Eq.6)$$

Where:

Parameters:

p_{min} = Minimum load of technology n, in region r

p_{HrLoad} = Load in hour h, in region r

$p_{Maxwind}$ = Maximum wind on day d, region r

$p_{Reserve}$ = Long-term system reserve requirement in region r

$p_{NetLoad}$ = Net load (load-wind) in hour h, region r

Constant numbers used for the calculation of Operating reserves requirements:

0.01 or 1%: represents the common error in the day-ahead hourly load forecast

0.2 or 20%: represents a maximum error in the day-ahead hourly wind forecast

0.5 (GW): is size of largest unit in the system (medium-sized plant of 500MW

considered)

According to the modeling assumptions an increase in the amount of wind in the system will lead to an increase in operating reserve requirements (both upward and downward) in the system,

equal to 20% in a particular hour. This 20% requirement corresponds to the maximum wind forecast error that is generally observed for the day ahead.

In addition, depending on how the Net Load is changing with the introduction of wind in the system the capacity margin might also increase. The Capacity Margin constraint takes into account the 100 peak hours of Net Load. So, it is expected that a lower capacity credit of wind (i.e., a lower contribution of wind to meeting demand over the peak 100 hours) will result in a higher capacity margin in the system.

In order to determine the effect of each one of these constraints I ran the model multiple times, relaxing one of them in each run. I found that the constraint that is mainly responsible for the introduction of additional thermal installed capacity is the Capacity Margin, followed by the Downward Operating Reserves and then the Upward Operating Reserves. This means that the low capacity credit of wind is the main driver for installing additional thermal capacity in the system in order to maintain a desired reliability level. On the other hand, there is almost no need to install additional thermal units in order to meet operating reserves requirements (except maybe at very large wind penetrations) as these requirements are mainly satisfied by existing units.

Before closing this discussion it should be mentioned that wind at large penetrations is not the only technology that would need additional backup capacity coming from flexible plants and would impose additional costs to the system. For instance, increasing penetration of inflexible nuclear plants in a given system would also place a burden on the remaining plants (e.g. Coal or CCGT plants) that would need to cycle more, in order to meet the constantly changing demand. In addition, large base load plants increase the need for operating reserves, an effect which is often ignored when considering the system cost of these plants but is taken into account when studying the integration cost of wind. This effect is very well illustrated by an example of the Spanish system operation as described in Perez-Arriaga (2012): In particular, the Spanish system has about 25GW wind and solar installed capacity. The System Operator requires 600MW wind- and solar-related regulating reserves, as well as an additional 1000MW of regulating reserves for the event of failure of the largest thermal plant (nuclear plant for Spain). Also, 1000MW of the interconnection capacity with France is also left unused in case the largest Spanish nuclear plant fails to operate and electricity imports from France are needed. Therefore, base load plants often impose costs to the system, as well, because of their inflexibility and/or their large size. In this work, however, I am focusing on the case of wind as this renewable technology is expected to reach large penetration levels and play a significant role in future decarbonized power systems.

Model limitations

The modeling approach that has been used gives a good sense of what happens in the system when large amounts of wind generation are introduced. However, for a more complete picture it is important that model assumptions and limitations are considered. The main ones that might affect the final results are:

- a) The operating reserves required because of wind are treated in a deterministic way. As it has already been described the reserves are calculated considering a 20% day-ahead wind forecasting error, which is a typical error size observed.
- b) Transmission is not taken into account in the model. As a result, grid expansion is not considered as an option for facilitating the integration of a large amount of renewables.
- c) Hydro is also not modeled. Hydro generation (excluding run-of-river hydro) is considered to be a flexible type of generation (see Table 5) that could provide load-following when a large amount of wind enters the system. Thus, one would expect that the presence of hydro resources in a system would cause less additional capacity of flexible plants to be installed at large wind penetration levels.

4 Modeling Intermittent Renewables in Computable General Equilibrium Models

4.1 The Emissions Prediction and Policy Analysis (EPPA) Model

For my analysis I am using the MIT Emissions Prediction and Policy Analysis (EPPA) model (Paltsev et al. 2005). The EPPA model belongs to a class of economic models known as Computable General Equilibrium (CGE) models, and in particular it is a recursive-dynamic CGE model. CGE models use actual socioeconomic data to estimate how an economy might react to changes in policy, technology or other external factors. They represent the circular flow of goods and services in the economy. Particularly, the supply of factor inputs (labor and capital services) to the producing sectors of the economy and the supply of goods and services from these producing sectors to final consumers (households), who in turn control the supply of capital and labor services. Corresponding to this flow of goods and services is a reverse flow of payments. As these models capture interactions among different economic sectors as well as different countries (through modeling international trade) they are a very good tool for analyzing the impacts of economic policies.

A CGE model is an economic model that typically combines the following:

- firms that attempt to maximize profits and minimize costs
- households who maximize “welfare” (e.g., consumption) by demanding commodities according to price
- markets that mediate behavior of economic agents (e.g., prices adjust until supply and demand are equal)
- government that collects taxes and spends revenue on consumption and transfer to households

Therefore, in principle, the equilibrium can be formulated as a constrained optimization problem (maximization of profits/welfare under supply/demand balance and resource constraints). However, the problem becomes intractable as the model gets more complicated. A solution to this is to formulate the equilibrium as a mixed complementarity problem (MCP). The logic behind this method is to define the equilibrium as the solution to a system of equations that embodies the underlying optimization behavior of economic agents (maximization of firms' profit and consumers' welfare). EPPA is formulated and solved as an MCP (Rutherford 1995). The equilibrium in complementarity format is represented by a non-negative vector of activity levels, a non-negative vector of prices, and a non-negative vector of incomes such that the following conditions hold:

1) Zero profit conditions: no production activity makes a positive profit - Output is the associated (dual) variable:

$$-profit \geq 0, output \geq 0, output^T(-profit) = 0$$

2) Market clearance conditions: excess supply (supply minus demand) is non-negative for all goods and factors - Price is the associated (dual) variable:

$$supply - demand \geq 0, price \geq 0, price^T(supply - demand) = 0$$

3) Income definition: expenditure equals income:

$$income = value\ of\ endowments$$

Constant Elasticity of Substitution (CES) Production functions for each sector describe the ways in which capital, labor, energy and intermediate inputs can be used to produce output. A very simple CES production function having only Capital and Labor as inputs has the following form:

$$X_t = \alpha_t (a_K K^{\rho_{KL}} + a_L L^{\rho_{KL}})^{1/\rho_{KL}}, \quad (Eq.7)$$

where $\sigma_{KL} = \frac{1}{1 - \rho_{KL}}$ is the elasticity of substitution, which is constant as relative input prices

change, α_K and α_L are the share parameters of input factors (with $0 < \alpha_K, \alpha_L < 1$), indicating the percentage of each input required to produce the output X_t , and α_t is determined in the calibration process so that the benchmark conditions are met. The elasticity of substitution represents the ability of individuals to make tradeoffs among the inputs to both production and consumption. Engineering cost data coming from bottom-up engineering models are normally used to parameterize a CES production function like that in Equation 7 (McFarland et al. 2004).

For $\sigma_{KL} > 0$ the function takes the following form:

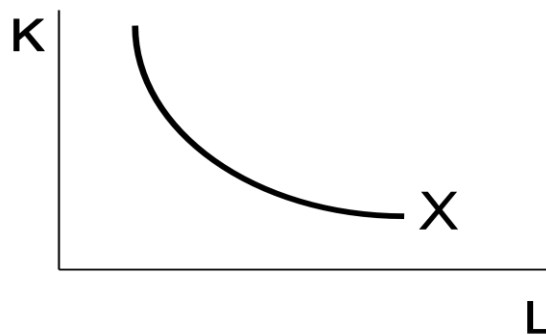


Figure 12 - Isoquant Curve: Combinations of Labor and Capital that yield the same output

The elasticity of substitution indicates how "easy" it is to substitute one input factor for the other in order to get the same amount of output (i.e., stay on the isoquant curve depicted in the figure above). If $\sigma=0$ then the input factors always need to be in the same proportion. If $\sigma > 0$ (the case shown in the figure) then K can be substituted for L. However, decreasing K by a certain amount, and wishing to get the same amount of output X will require an increase in L which is determined by the exact place on the isoquant on which the equilibrium lies. So, if we are at equilibrium towards the right end of the curve (large L, small K) and we want to substitute even more K with L then in order to stay on the same X curve we need to add many units of L for each unit of K that we give up. This happens because of the particular curvature of the isoquant. The case of $\sigma=\infty$ implies that K and L are complementary, which means that we can always substitute an amount of K with the same amount of L no matter where the equilibrium lies on the isoquant curve.

A limiting feature of the CES function is that with more than two inputs, the elasticity of substitution is identical between all pairs of inputs. This limit is overcome by 'nesting' inputs, that is, by representing sub-groups of inputs as separate CES functions, and aggregating these nests using CES functions (Figure 13, Figure 14). It is then possible to specify a separate elasticity for each of these nests.

4.2 Power Sector Representation in the EPPA model

Top-down models, such as CGE models, typically treat electricity production as a single sector with capital, labor, material, and fuel inputs. In EPPA, the production structure for electricity is the most detailed among the sectors (Figure 13). The top level nests allow treatment of different generation technologies, both generation technologies that exist in the base year data (conventional fossil, nuclear, and hydro) and advanced (new) technologies that did not exist in the base year data. Most of these new technologies enter as perfect substitutes for existing technologies, signified by $\sigma = \infty$ at this nest level. The exception is the Wind & Solar technologies that enter at the very top of the nest, and substitute for other electric technologies as controlled by σ_{EWS} . Treatment of Wind & Solar as imperfect substitutes tends to limit their penetration share - depending on the cost of conventional technologies - representing the fact that the intermittency of these renewable sources might add to their cost if they were to provide a large share of electricity production.

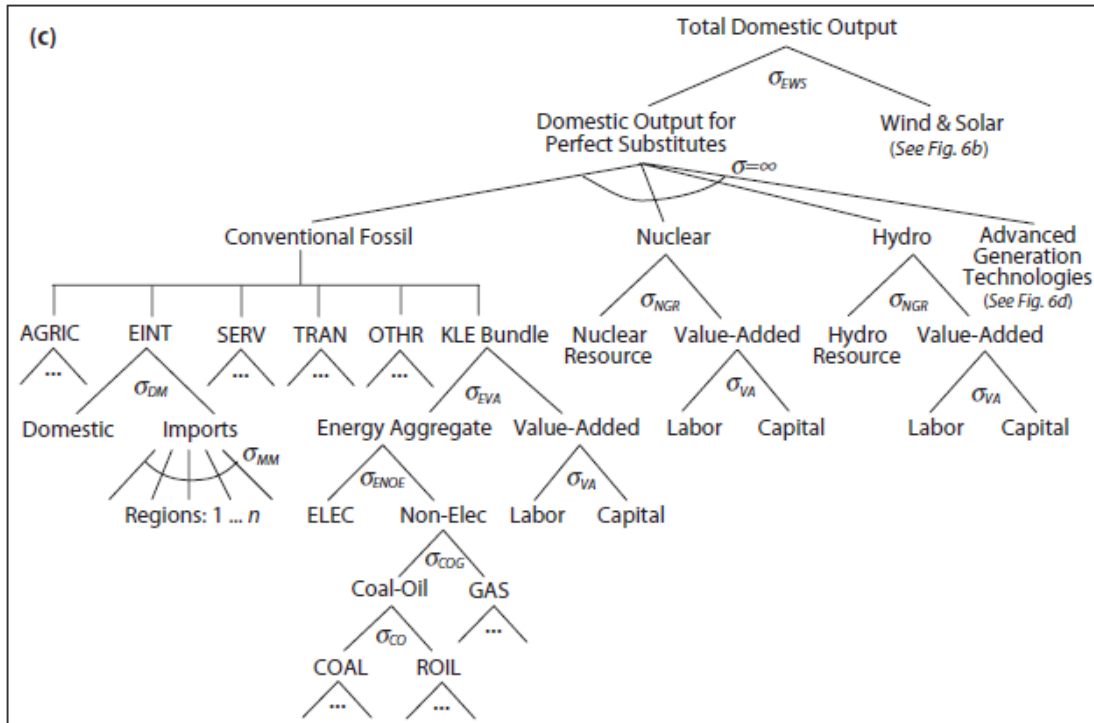


Figure 13 - Structure of Electricity Production sector in EPPA

Conventional fossil does not separately represent coal, oil, and gas generation technologies, but instead treats these via direct substitution among the fuels. This has the advantage of limiting substitution among fuels, thus representing their unique value for peaking, intermediate, or base load.

In general, aggregation of many technologies in the same production function is a simplification used in CGE models (compared to bottom-up electricity models). In EPPA, however, the effect of this limitation has been minimized; new technologies - including wind, solar, biomass and advanced fossil fuel technologies - as well as nuclear and hydro have been disaggregated and are treated in separate functions.

In particular, the structure of wind (and solar) generation in EPPA is represented in Figure 14:

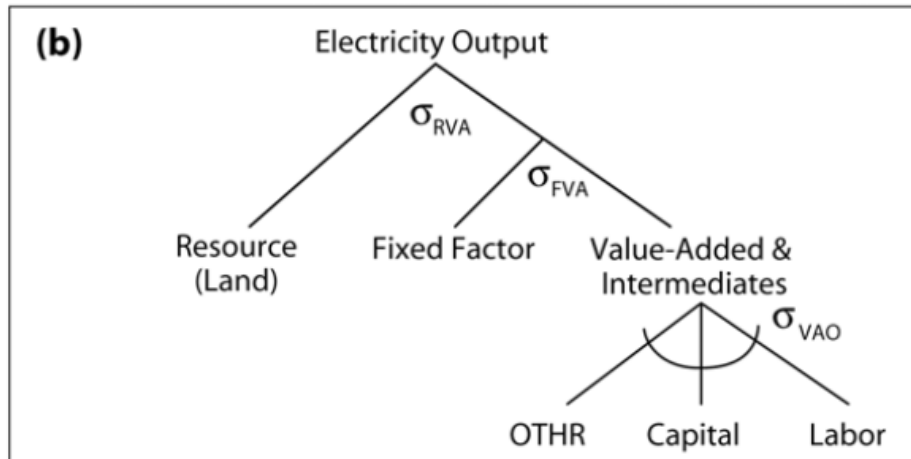


Figure 14 - Structure of intermittent renewables in the EPPA model

Comparing the representation of the power sector in a top-down CGE model (like EPPA) with that in a bottom-up electricity model (like the one used in this work and described in Chapter 3) reveals the different approaches used and provides a guide when trying to introduce more power sector detail in CGE models .

Bottom-up electricity models depict in detail a rich set of representative energy technologies, and can be used, for example, to identify the least-cost mix of technologies for meeting a given final energy demand under greenhouse gas emissions and other constraints. However, they often take energy and other prices as exogenous and thus, may over- or under-estimate the penetration level of a particular technology (McFarland et al. 2004). On the other hand, in the top-down approach the particular focus is on market and economy-wide feedbacks and interactions, often sacrificing the technological richness of the bottom-up approach.

The inputs of electricity production in a CGE model correspond to electricity costs used in bottom-up models. For example, the capital input in CGE corresponds to capital costs in bottom-up models, the energy input in CGE (e.g. "Energy Aggregate" input in Figure 13) corresponds to fuel costs while labor costs in CGE models represent operations, maintenance and other administrative costs.

In the case of wind, capital expenses represent 40% of the total cost and labor expenses represent 25% of the total cost. There are no fuel expenses. The OTHR input is any intermediate input, such as materials, that comes from other sectors of the economy. The land resource input is the cost of land occupied by wind farms. Finally, the fixed factor input is used to slow down the initial penetration of new technologies and works as follows: The representative agent is endowed with a small amount of the fixed factor resource. The endowment of this resource grows as a function of output in the previous period. Capacity expansion is thus constrained in

any period by the amount of this fixed factor resource and the ability to substitute other inputs for it. As output expands over time the endowment is increased, and it eventually is not a significant limitation on capacity expansion. So:

$$FF_t = f(Y_{t-1}, FF_{t-1}, FF_0), \quad (\text{Eq.8})$$

where FF is the quantity of fixed factor in year t , Y_t is the output from the technology at time t , and FF_0 is the exogenous initial endowment.

The intuition behind this specification is the following: at the start-up of a new industry there is limited trained engineering capacity to build plants with the new technology. With significant demand for capacity expansion, engineering firms with this capacity earn rents. These new firms gain experience (or the newly hired staff gain experience) and this expands the endowment of the fixed factor for future periods. Thus, over time the rents associated with this fixed factor mostly disappear. Parameterization of this adjustment cost process is based on observations of the ability of nuclear power to expand over from its introduction to the mid 1980s.

A limitation in the CGE model representation of the power sector is the fact that the electricity production functions do not distinguish between adding capacity and increasing generation. In particular, the equilibrium is solved in terms of value and corresponding energy use or output and then, capacity is calculated using an external assumption about the capacity factor. When introducing a lot of wind in the system, however, the total system installed capacity increases even if the total energy remains the same. This happens because wind is intermittent and thus, some dispatchable capacity needs to stay in place in order to meet demand whenever wind fails to do so. The result of having more installed capacity for the same demand is that the capacity factors of units in the system change. Normally, thermal units start operating at lower capacity factors, which can have a significant impact on their economics. However, by not making the distinction between energy and capacity CGE models fail to capture this effect.

4.3 Representing Wind Intermittency in the EPPA model

The main challenge that has been addressed by this work, is to represent in EPPA the costs and limitations in the system because of wind intermittency while, at the same time, preserving the nesting structure of the model.

Different ways of dealing with this challenge have been identified and are presented here.

4.3.1 Conventional approach

The approach that is currently used for modeling intermittent renewables, and particularly wind power, in EPPA is described in Morris (2009) and is summarized here.

In the current EPPA version, there is a different treatment of wind in small and wind in large penetrations (they can be called Type I and Type II Wind respectively). The main rationale behind this distinction is the fact that wind in small penetrations can be introduced in the system with some cost but without requiring significant additional thermal backup capacity built. The system is able to deal with wind power fluctuations, as it does with demand fluctuations. However, when wind generation covers a larger portion of demand, there is a requirement for more flexible generation and this is captured in the structure of Type II wind.

The competitiveness of advanced electricity technologies, including renewables, is largely determined by the so called “cost markup”, which is the cost of a particular technology relative the cost of electricity from the current power system mix (usually related to the cost of coal generation in the base year of the model). The markup is basically derived from dividing the Levelized Cost of Electricity (LCOE) of a particular technology with that of coal. The LCOE is the most commonly used metric for comparing the costs of electricity generation across different technologies. It takes fixed and variable costs into account and is expressed in \$ per unit of electricity generated (\$/MWh). The capital and fixed O&M costs are expressed in \$/MWh by being spread over the expected quantity of electricity generated per year. This electricity depends on an average capacity factor that is considered, which is higher for base load plants and lower for peaking plants or intermittent renewables.

Wind in small penetrations (Type I) is modeled as an imperfect substitute for electricity from conventional, dispatchable generation. This wind is assumed to be the "cheapest" wind that can be obtained, i.e., located at sites with access to the best quality resources and at locations most easily integrated into the grid. The elasticity of substitution creates a gradually increasing cost of production as the share of renewables increases in the generation mix. Thus, the markup cost strictly applies only to the first installations of these sources, and further expansion as a share of overall generation of electricity comes at greater cost. Choice of the substitution elasticity creates an implicit supply elasticity of wind in terms of the share of electricity supplied by the technology. The value chosen for this elasticity results in relatively inelastic supply in terms of wind share, with it reaching at most 15 to 20% of electricity supply in any region, even under relatively tight constraints on carbon that lead to increased cost of generating electricity from fossil energy sources.

In order to model wind at larger penetrations (Type II) two new renewable technologies have been introduced: wind with NGCC backup ("windgas") and wind with biomass backup ("windbio"). These technologies are perfect substitutes for the rest of the electricity generation

technologies. Because now the elasticity of substitution (which is infinite) does not create a gradually increasing cost of production as the share of these two technologies increases in the generation mix, the additional costs for large scale wind (transmission and storage or backup) are incorporated into the markup costs of the new technologies. In particular, it is assumed that for each kW installed capacity of wind there is one kW backup capacity (either NGCC or biomass). This backup plant is operating at a low capacity factor (7%), which was motivated by high-penetration renewable scenarios, when up to 80% of electricity comes from renewables. In order to calculate the markup of the "windgas" technology the "Overnight" Capital Cost, Fixed O&M, Variable O&M and Capacity Factors of Wind and NGCC technologies are added. The results appear in Table 7.

Table 7 - Calculation of markup factors for Wind, NGCC and Windgas technologies in EPPA

	Units	Wind	NGCC	Wind Plus NGCC Backup [a]
"Overnight" Capital Cost	\$/kW	2278	929	3207
Total Capital Requirement	\$/kW	2460	1003	3464
Capital Recovery Charge Rate	%	10.6%	10.6%	10.6%
Fixed O&M	\$/kW	28.6	11.0	39.6
Variable O&M	\$/kWh	0.0000	0.0019	0.0019
Project Life	Years	20	20	20
Capacity Factor	%	35%	85%	42%
(Capacity Factor Wind)				35%
(Capacity Factor NGCC)				7%
Operating Hours	Hours	3066	7446	3679.2
Capital Recovery Required	\$/kWh	0.08	0.01	0.10
Fixed O&M Recovery Required	\$/kWh	0.01	0.001	0.01
Heat Rate	BTU/kWh	0	6333	6333
Fuel Cost	\$/MMBTU	0.00	8.00	8.00
(Fraction NGCC)	%			8.2%
Fuel Cost per kWh	\$/kWh	0.0000	0.0507	0.0042
Levelized Cost of Electricity	\$/kWh	0.094	0.068	0.116
Markup Over Coal For EPPA		1.48	1.07	1.82
Transmission and Distribution	\$/kWh	0.02	0.02	0.03
Cost of Electricity	\$/kWh	0.10	0.09	0.15
Markup Over Coal		1.36	1.05	1.75

As shown earlier in this Chapter, the 1-to-1 NGCC "backup" working at a 7% capacity factor does not exactly agree with the bottom-up electricity model outcomes, which indicate that:

- As wind penetration increases both NGCC plants and peaking Gas Turbines are installed in the system.
- The NGCC plants installed have higher capacity factors than the Gas Turbines installed and also higher capacity factors than what is currently assumed for them (7%).

Next, the currently used approach is updated, taking into account the outcomes from the electricity model runs.

4.3.2 Informing conventional approach with bottom-up model results

The results of the bottom-up electricity model presented in

Table 6 show that: in order to meet a particular amount of new demand with wind generation while keeping the same level of reliability, wind should be accompanied by thermal generation - either Gas Turbines or Combined Cycle Gas plants - and this is the cost-minimizing solution⁴.

In an attempt to integrate this more realistic treatment of wind intermittency into the EPPA model the new markup for the "windgas" technology was calculated - with the process described in Table 7 - and a very interesting observation was made:

The markup factor of the "windgas" technology with a lower NGCC plant capacity per kW of wind installed and with a higher capacity factor than before (i.e., more than 7%) tends to be lower than that of wind alone. For example, using the numbers that were found in Table 6 for the North-Central region, windgas markups for 40% to 60% wind penetration are as follows:

Table 8 - Windgas markups for different wind penetration levels (Source: own calculations)

Wind penetration	Windgas markup
40%	1.36
50%	1.34
60%	1.33

For the wind penetration levels considered, gas turbine additional capacity is negligible compared to NGCC additional capacity (Table 6) so, it has not been taken into account in the above calculations.

⁴ This result was obtained when starting from a perfectly adapted mix.

Therefore, the combination of wind with a flexible thermal plant is, in many cases, more competitive than wind itself (which has a markup of 1.36)⁵. This result might sound counterintuitive. However, the LCOE calculation formula below⁶ shows that it is possible to get a lower LCOE when combining two technologies if the Operating Hours of the combined technology (i.e., the combined capacity factor) exceed a certain level and/or the amount of additional thermal capacity required per kW of wind installed, denoted with α , is below a certain level.

LCOE_Comb (in \$/kWh) =

$$\frac{a * FixO \& M(g) + FixO \& M(w)}{CombOpHrs} + VarO \& M(g) + \frac{\alpha * CapCost(g) + CapCost(w)}{CombOpHrs} + FuelCost * HR * \frac{OpHrs(g)_{wg}}{OpHrs(g)_{def}}$$

(Eq.9)

where, g = NGCC, w = wind, FixO&M=Fixed Operations and Maintenance Costs, VarO&M = Variable Operations and Maintenance Costs, CapCost = Capital Cost, HR = Heat Rate of NGCC plants, OpHrs = Operating hours, CombOpHrs = Combined Operating Hours for windgas technology, wg = windgas (i.e., OpHrs based on the capacity factor of NGCC's that are part of the windgas technology), def = default (OpHrs based on the standard 85% capacity factor assumed for NGCC plants).

In Section 5.1.2, a policy scenario is simulated using this low windgas markup, indicating its effect on the energy mix.

4.3.3 New approach: Introducing System Flexibility requirements

A new approach that can improve the treatment of intermittent renewables in the model is proposed in this thesis. According to this approach, what needs to be captured is the fact that increasing wind penetration requires increasing "flexibility" in the system, as was shown by the electricity model runs presented in Chapter 3.

A recent IEA study titled "Harnessing Variable Renewables: A Guide to the Balancing Challenge" defines power system flexibility in the following way:

⁵ Strictly speaking, wind and windgas should not be directly compared. In reality, "wind itself" is not an option, since we can never meet an increase in demand with just wind while keeping the same reliability target.

⁶ This is a simplified form mainly for illustration purposes.

Flexibility expresses the extent to which a power system can modify electricity production or consumption in response to variability, expected or otherwise. In other words, it expresses the capability of a power system to maintain reliable supply in the face of rapid and large imbalances, whatever the cause. It is measured in terms of megawatts (MW) available for ramping up and down, over time. For example, a given combined-cycle gas turbine (CCGT) plant may be able to ramp output up or down at 10 MW per minute (IEA 2011a).

The characteristics of intermittent generation combined with the need to maintain a constant balance between load and generation create challenges for system operators, who will require greater flexibility in the system to ensure reliability and meet policy goals. In the absence of economically viable large-scale storage, the burden of maintaining system reliability will fall mostly on the flexible operation of thermal generation units, such as coal, natural gas, nuclear and hydropower, where available. However, the ability of these plants to operate flexibly is limited both by physical plant constraints and economic profitability considerations.

According to the findings of the 2011 MIT Energy Symposium on "Managing Large-Scale Penetration of Intermittent Renewables", the most important requirements for the flexible operation of thermal generators are partial load efficiency, fast ramping capacity, and short startup times. Table 5, presented in Section 3.3, compares the flexibility of gas plants with that of other thermal units. In brief:

- Coal plants and current nuclear plants were not designed specifically for a flexible operation, and their economics are affected significantly if they are called upon to operate in load-following mode.
- Coal plants can generally ramp their output at 1.5%–3.0% per minute, and expected maintenance costs increase with increasing ramp rates.
- Relatively new nuclear reactors ramp asymmetrically: plants can down-ramp 20% of their total output within an hour, but they require six to eight hours to ramp up to full load. Also, nuclear plant ramping operations are not fully automated. Operating a nuclear plant in a transient state requires manual manipulations that create additional opportunities for operator error.
- Natural gas plants, on the other hand, provide the greatest generation flexibility to mitigate large-scale penetration of intermittent renewables with ramp rates of 8% per minute. New natural gas combined cycle (NGCC) plants continue to improve their capabilities for responding to the intermittency of renewable generation.

Although, theoretically, coal, natural gas, and nuclear plants physically are able to ramp and cycle to varying degrees, doing so will negatively impact their operations, maintenance schedules and expected operational lifetimes. Retrofits, advanced control systems, and newer

plant designs can improve flexible operations and provide better monitoring of physical wear, but these upgrades are not trivial and they are expensive.

In order to capture flexibility requirements the following changes are made in the model:

a) Wind: A new wind technology is added to the model, considered to be a perfect substitute for electricity from dispatchable sources (i.e., fossil fuel and advanced fossil fuel technologies, nuclear and hydro). Its input structure is the same as Wind Type I but its penetration is not limited by a finite substitution elasticity as was the case for Wind Type I. "Windgas" technology described in section 4.3.1 is not used anymore in the new approach. For the simplicity of calibration of wind generation to the current production levels, I still use Type I Wind - i.e., wind at small penetrations, modeled as an imperfect substitute for electricity – because it simplifies a representation of relative economics and regulatory regimes across different European countries that results in the wind generation in the base year of the model. The impacts of higher penetration levels are evaluated based on the new approach of the wind technology modeling.

b) Flexibility: In order to ensure that the system has enough flexible generation to deal with the increasing fluctuations in the net load because of large wind penetrations:

- i. A system "flexibility" input is added to Wind production function as shown in Figure 15. This input indicates a minimum requirement for generation from flexible technologies in the system and increases as wind penetration increases. The "flexibility" input is introduced at the top nest with a very low elasticity of substitution (close to zero) so that it is not affected by the nesting structure at lower levels.

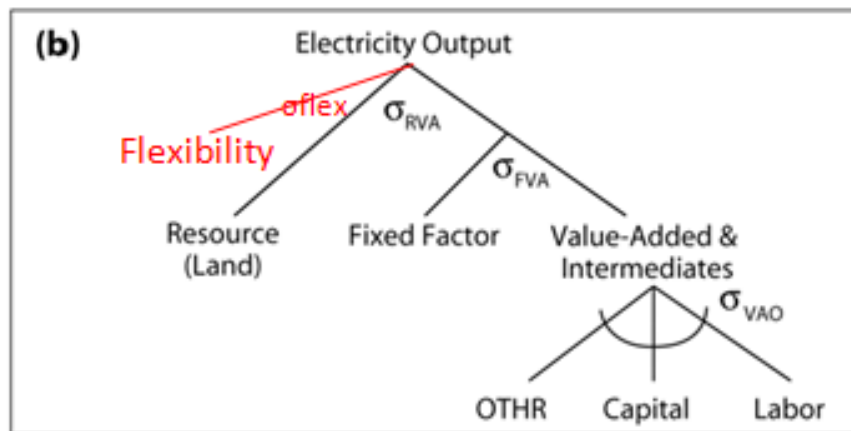


Figure 15 - Wind production function with "flexibility" input added.

- ii. A "flexibility" output is added to the production function of each dispatchable generation technology (such as coal, gas, hydro and biomass technologies) corresponding to the contribution of each technology to "system flexibility". Each technology produces a different amount of "flexibility" depending on how flexible the technology is. As there is currently no single universal metric of the flexibility provided by a generation plant, a methodology for determining the amount of flexibility attributed to each technology was invented in this work. The "flexibility" input requirement for wind and the "flexibility" output from each technology were specified using the bottom-up electricity model, as described below, while the outcomes found in literature were also taken into account.
- iii. With the additional input and output requirements ((i) and (ii)) in each loop an additional constraint is introduced:

$$\sum_{i=1}^N fd_i \geq fw_p, \quad (\text{Eq.10})$$

where fd_i is the flexibility output from dispatchable technology i and fw_p is the flexibility input requirement of wind at penetration p .

With this constraint it is ensured that the system is flexible enough to deal with the additional fluctuations in the net load because of wind intermittency.

Determining the "system flexibility" requirement for each wind penetration, as well as quantifying the amount of "flexibility" that each dispatchable technology offers to the system is a challenging problem. It is true that this requirement will be different for different systems, depending on wind and load patterns and on initial generation mixes. This was verified by the bottom-up electricity model simulations discussed in the previous sections. When running the model for different US regions with distinct characteristics the results differed. In particular, for regions that have a higher wind resource, such as Texas or the North-Central States, wind can be added without a significant requirement for flexible generation in the system compared to States with a lower quality of wind (such as New England). In addition, regions that already have a flexible system with lots of natural gas plants installed or a lot of hydro also require less additional flexible generation compared to regions that have a generation mix based on coal or nuclear, for example. Therefore, system flexibility requirements for various wind penetrations will be different for different systems.

However, even if we focus on a particular system with specific characteristics, there is no established way to quantify the flexibility of different technologies and of the system as a whole, and in fact, this is an area of significant debate. A noteworthy attempt to find a single metric that characterizes flexibility is described in Ma et al. (2013).

Here, a different approach for determining the flexibility requirements was used:

I started from a system with a very inflexible initial generation mix, having a significant amount of nuclear capacity installed (in particular, nuclear installed capacity equal to the minimum system load). The actual hourly wind and load curves for the system were used but the initial generation mix was "created" so that it represents an extreme case of inflexibility. Then, for different wind penetrations the generation mix was optimized, only "allowing" flexible (i.e., natural gas) plants to be installed (in addition to the nuclear that already existed and the wind that was imposed). Because a highly inflexible initial mix was considered and given that the electricity model is cost-minimizing (i.e., it will install the minimum amount of new technologies in order to meet demand), the assumption is that any other mix that could "accommodate" the same level of wind penetration would have at least as much flexible generation as the one found for the hypothetical extremely inflexible system.

By repeating the process for nuclear-coal-wind (instead of nuclear-natural gas-wind), I found the amount of coal in the system needed to accommodate the specified wind penetration levels. As expected, a larger amount of coal generation is required (compared to natural gas) for the same wind penetration because coal is less flexible - in the sense that it has slower ramping rates, longer startup times and is less economical for short- or mid-utilization factors. From this information I determined the relative "flexibility" between coal and natural gas technologies (see Figure 16 below).

Nuclear is considered to have zero flexibility, natural gas units have the maximum flexibility and coal units lie in between the two. The rest of the technologies in the system can also be assigned "flexibility" values. Hydro is treated like natural gas plants in terms of "flexibility" and biomass is treated like coal plants.

The following figures show the relationship that was found between the penetrations of "Wind and GTs", "Wind and NGCCs" and "Wind and Coal plants" in the system, when systems with a hypothetical initial mix were simulated consisting of "Nuclear-GTs-Wind", "Nuclear-NGCCs-Wind", and "Nuclear-Coal plants-Wind" respectively. This information was used in order to identify an approximate relationship between the "flexibility" of GTs, NGCCs and coal plants.

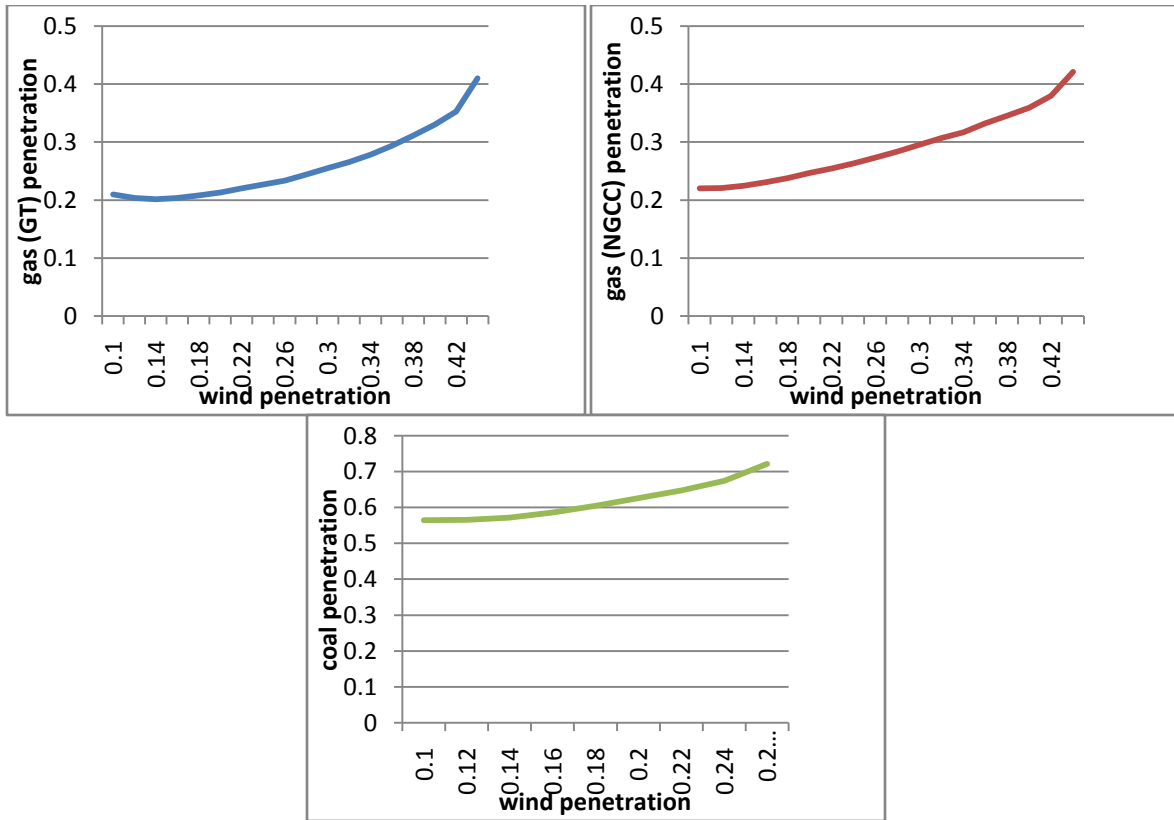


Figure 16 - Wind penetration vs. GT/NGCC/Coal penetration for the New England system using a hypothetical inflexible initial mix (Source: own calculations).

Using the information from these graphs and assuming that the flexibility of nuclear technology is zero and the flexibility of GTs is 1, then:

$$Flex(NGCC) = \frac{Flex(GT)}{1.2}$$

$$Flex(Coal) = \frac{Flex(GT)}{2.8}$$

These numbers are derived from dividing the requirements of generation from GTs to those of generation from NGCCs or Coal plants respectively, for each wind penetration level, and taking the average of the results. In order to limit the uncertainty involved due to the unique characteristics of each power system, the runs were repeated for several U.S. systems.

For the case of "Wind and NGCCs" the graphs for different U.S. systems appear in Figure 17:

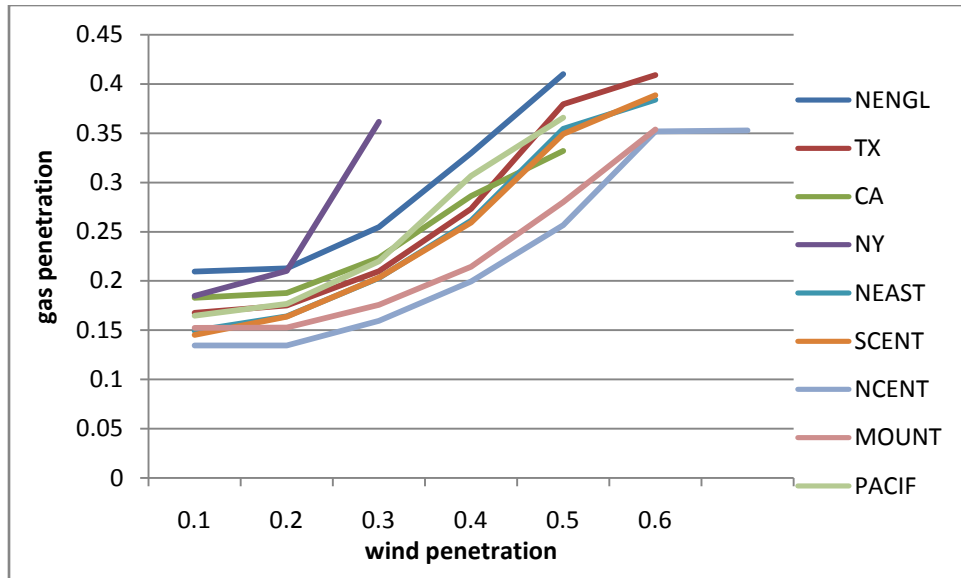


Figure 17 - Wind penetration vs. NGCC penetration for different U.S. systems using a hypothetical inflexible initial mix (Source: own calculations).

(NENGL = Maine, New Hampshire, Vermont, Massachusetts, Connecticut, Rhode Island; SEAST = Virginia, Kentucky, North Carolina, Tennessee, South Carolina, Georgia, Alabama, Mississippi; NEAST = West Virginia, Delaware, Maryland, Wisconsin, Illinois, Michigan, Indiana, Ohio, Pennsylvania, New Jersey, District of Columbia; SCENT = Oklahoma, Arkansas, Louisiana; NCENT = Missouri, North Dakota, South Dakota, Nebraska, Kansas, Minnesota, Iowa; MOUNT = Montana, Idaho, Wyoming, Nevada, Utah, Colorado, Arizona, New Mexico; PACIF = Oregon, Washington, Hawaii)

From the graph above it can be seen that when wind is introduced in areas with a larger wind resource on average, such as NCENT and SCENT (Guntutu et al. 2012) lower amounts of flexible resources are required in order to deal with net load fluctuations compared to areas with a lower wind resource, such as New England. It should be stressed again here that - up to now - the initial generation mix of each region has not been taken into account in the calculations. The graph above could, thus, be interpreted as: for a very inflexible initial mix, a particular penetration of wind in a system would require some generation from NGCCs, as well, that is different for different systems, mainly depending on their wind and load profiles. So, based on the results presented, the system of New England would require more flexible generation per unit of wind installed than the system of Texas. However, if a system has a very flexible initial generation mix (including, for example, lots of gas or hydro plants) then, the system flexibility requirement (as shown in Figure 17) might be satisfied without any addition of flexible generation. For instance, the New England system is already equipped with a flexible initial generation mix (GE Energy 2010). Thus, the additional requirement for flexible generation might be smaller than, say, the North-Central system that has a higher wind resource on average but an inflexible initial mix. The implementation of the "system flexibility" requirement in EPPA aims to capture these interactions.

Even though the approach used for calculating "flexibility" is actually a heuristic-based approach, it is valid for current generation mixes that have been tested as well as future generation mix projections found in Outlooks (EC 2011). Of course, as already explained, better quantifying this "flexibility" is an area that needs to be researched more.

For small wind penetrations the flexibility constraint (Eq.10) is not binding, which means that the system has the required amount of flexibility anyway (in order to meet already existing fluctuations in demand). The constraint becomes binding for larger penetrations of wind for which the system must have a minimum amount of flexible technologies installed. Examples of outcomes when this approach is used are presented in the next Chapter.

With this approach it is ensured that the system is flexible enough in order to accommodate a large wind penetration. "Flexibility" can be provided by many different technologies, which means that it is not restricted to natural gas units. However, some technologies can provide greater flexibility to the system than others due to inherent characteristics. Ideally, in future systems "flexibility" will also be provided by the demand-side, through demand response or controllable load such as electric vehicles, by electricity storage or optimal use and expansion of networks (Conejo 2011). These options are not considered here. Instead, the focus is on installing flexible thermal generation for load-following.

Other approaches could also be used for capturing the effects of wind intermittency. An approach not implemented here but worth mentioning is the one described in Chen (2012). Chen has created a CGE model for Taiwan in which wind is treated as shown in the figure below. For wind power, there is again a fixed factor that controls its expansion potential. The quantity of the fixed factor is considered proportional to the dispatchable generation capacity in the system (and particularly the sum of gas and hydro generation). The higher the quantity of the fixed factor available the lower its price and thus, the lower the cost of wind generation. Therefore, having more dispatchable capacity in the system results in a greater quantity of the fixed factor (as these quantities are proportional), which in turn makes wind cheaper and allows it to grow faster. With this treatment that Chen follows wind capacity is limited by the amount of flexible dispatchable generation in the system.

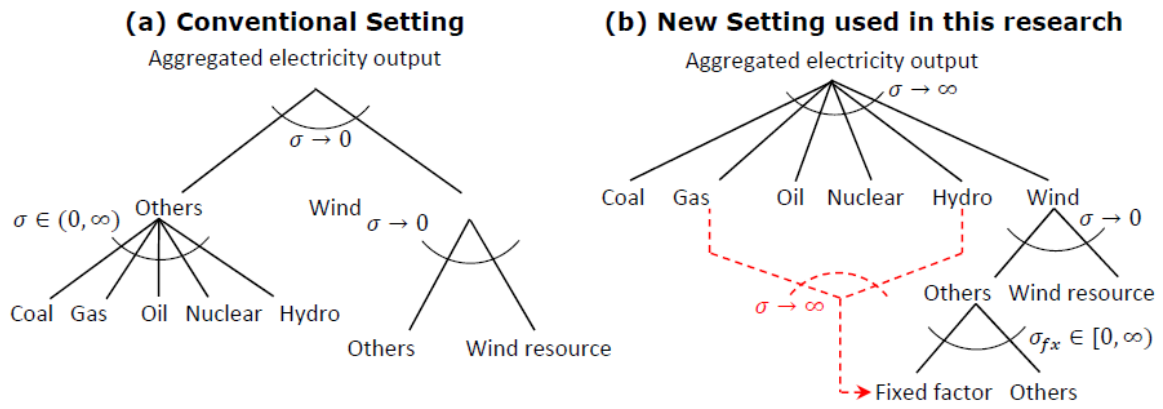


Figure 18 - Structure of Modeling Wind Generation (Source: Chen 2012)

5 Case Study: European GHG Emissions Reduction by 2050

In this Chapter an application of my new methodology to the case of Europe is presented. I focus on Europe as it seems that currently the EU has the most ambitious goals in terms of renewable energy penetration by mid-century. The goals are driven by several factors: In order to prevent the most severe impacts of climate change, the international community has agreed that global warming should be kept below 2°C compared to the temperature in pre-industrial times. Around 11% of the greenhouse gases emitted worldwide each year come from within the European Union. The EU long-term goal involves a 2020 mid-term strategy described in the “EU climate and energy package” (EC 2011b) that aims to achieve i) a 20% reduction in EU greenhouse gas emissions (GHG) from 1990 levels, ii) a 20% share of renewables in final energy consumption and iii) a 20% improvement in the EU's energy efficiency. Whereas the first two targets are binding, the latter is only indicative. The national emissions reduction targets, covering the period 2013-2020, are differentiated according to Member States' relative wealth. They range from a 20% emissions reduction (compared to 2005) by the richest Member States to a 20% increase by the least wealthy. Overall, the EU is making good progress towards achieving the emissions target. In 2010, combined greenhouse gas emissions from all 27 Member States were 15% below the 1990 level. Regarding the renewables share targets, under the Renewable Energy Directive, Member States have taken on binding national targets by 2020, reflecting their different starting points and potential for increasing renewables production, ranging from a 10% share in Malta to a 49% share in Sweden. The national targets will enable the EU as a whole to reach its 20% renewable energy target for 2020 - more than double the 2010 level of 9.8%. Currently, there is a long discussion on whether and how these targets will be continued after 2020 (EC 2013). The uncertainty that is being created among investors, governments and citizens makes the task of developing post-2020 strategies urgent.

In December 2011 the European Commission issued the "EU Energy Roadmap 2050" (EC 2011) in which an 80-95% GHG reduction by 2050 compared to 1990 levels is proposed. Three main goals of the European climate policies are mentioned: a) decarbonization of the energy sector, b) energy security and c) competitiveness. The 2050 targets are not binding and the particular policies that should be implemented in order to achieve them have not been decided yet.

Numerous studies have shown that the power sector will play an important role in achieving these targets (e.g., Knopf et al, 2013). Power generation is the largest CO₂ emitting sector making up for 36% of total energy-related CO₂ emissions in Europe and more than 43% in the US in 2010 (IEA 2012).

According to the Roadmap (EC 2011) the power sector has the biggest potential among sectors for cutting emissions and it can almost totally eliminate its CO₂ emissions by 2050. Therefore, electricity will come from renewable sources like wind, solar, hydro and biomass or other

sources that have low carbon emissions, such as nuclear power plants or fossil fuel plants with carbon capture and storage (CCS). However, there are various paths that this de-carbonization can take depending on factors such as the level of world energy prices, the dynamics of markets, the development of future technologies, the availability of natural resources, social changes and public perception. For instance, whether and to what extent shale gas in Europe will prove viable, whether and when Carbon Capture & Storage (CCS) will become commercial, what role Member States will seek for nuclear power, how climate action across the globe will evolve are just some of the factors that might change the way that the power system will meet the decarbonization target. To this extent, among the scenarios studies in the Roadmap are a Low Nuclear, a Delayed Carbon Capture and Storage, as well as a High Renewable Energy Sources and a High Energy Efficiency Scenario. In all scenarios renewables (including hydro, wind, solar, tidal, biomass and geothermal) play a very important role, their penetration in 2050 ranging from 48.8% of total electricity generated (if continuation of current policies is assumed) to 83.1% in the "High Renewables Scenario". Particularly, the penetration of wind power in 2050 ranges from 24.7% to 48.7% of total electricity generation. This is a large increase compared to current levels.

In 2012 wind penetration in the EU was 7% of total electricity demand. Of course, different countries have different wind shares of total electricity consumption as shown in the following figure.

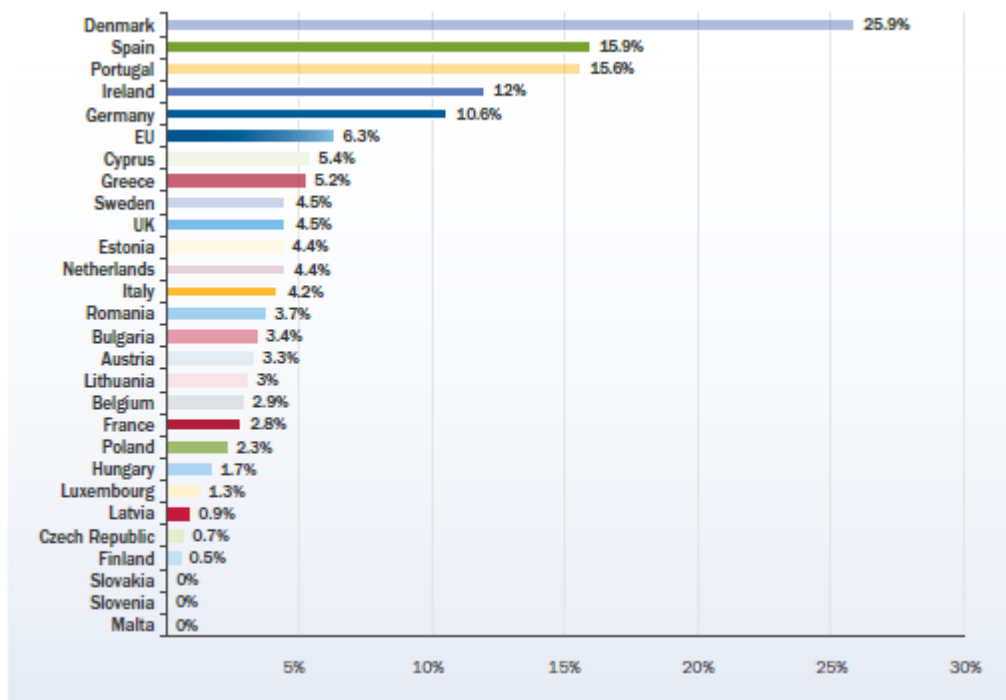


Figure 19 - Wind share of total electricity consumption for different European countries (Source: EWEA 2012)

Also, wind power accounted for 26.5% of total 2012 power capacity installations, while annual installations of wind power have increased steadily over the last 12 years, from 3.2 GW in 2000 to 11.9 GW in 2012, a compound annual growth rate of over 11.6% (EWEA 2012).

Traditionally, wind generation in Europe has been supported by various policy mechanisms in different countries. EU member states use feed-in systems, quota obligations with tradable green certificates, investment grants and tax incentives to support renewable electricity generation. The map in Figure 20 shows that feed-in systems (i.e., feed-in tariffs or feed-in premiums) are the most commonly used support scheme. The number of countries using feed-in systems has increased steadily from 9 states in 2000 to 18 in 2005 and 24 in 2012 (Ragwitz et al. 2012).

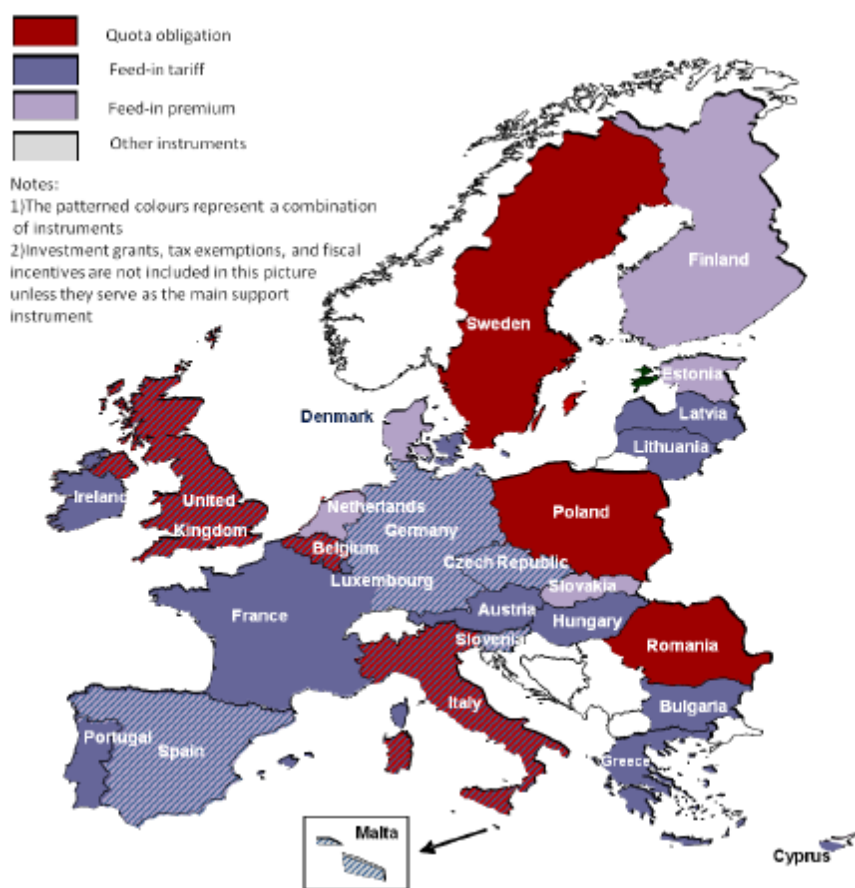


Figure 20 - Renewable support mechanisms of EU countries in 2011

Feed-in tariffs guarantee a fixed price per kWh electricity and offer long-term certainty to investors. Thus, this mechanism is appropriate for the very early stage of a technology. On the other hand, feed-in premiums are paid on top of the market price for electricity, which exposes

developers to electricity market prices (Batlle et al. 2011). Thus, feed-in-premiums can be used as a transitioning scheme towards a complete exposure of wind producers to market prices.

Moving forward, the European Wind Energy Agency holds that beyond 2020 support mechanisms should be kept in place as they are the best tool to counteract market failures in the electricity sector, in the absence of a well-functioning and harmonized EU electricity market, and without taxation fully internalizing environmental costs. However, they should be adapted to technology maturity and with increasing wind energy penetration levels, they should encourage greater market responsiveness by making producers exposed to price signals. This will ensure that they take an active part in making the market as efficient as possible.

5.1 Scenarios Modeled

In this Chapter, two emissions reduction scenarios are modeled: a linear path to 40% GHG emissions reduction and a linear path to 80% GHG emissions reduction by 2050 relative to 1990 levels. The policies start in 2015. These scenarios are chosen for illustrative purposes as they were used for the European Energy Modeling Forum 28 - a European-wide modeling comparison that was recently completed (Knopf et al. 2013). For each scenario the two approaches for modeling wind intermittency are compared:

- i) Conventional Approach: Wind as an imperfect substitute at low penetrations, Wind with 1-for-1 NGCC backup at high penetrations (i.e., *windgas* approach described above).
- ii) New - "Flexibility" - Approach: Wind as a perfect substitute with other electricity generation, where wind generation is modeled with "system flexibility" requirements.

5.1.1 Scenario I - 40% GHG Reduction by 2050

Scenario I represents a relatively moderate target for the EU - 40% GHG emissions reduction by 2050 compared to 1990 levels. The 40% target refers to the total emissions coming from all economic sectors - i.e., the policy is not particularly targeting the power sector. Figures 21 and 22 show the resulting electricity generation mix in the two approaches.

- i) Conventional Approach:

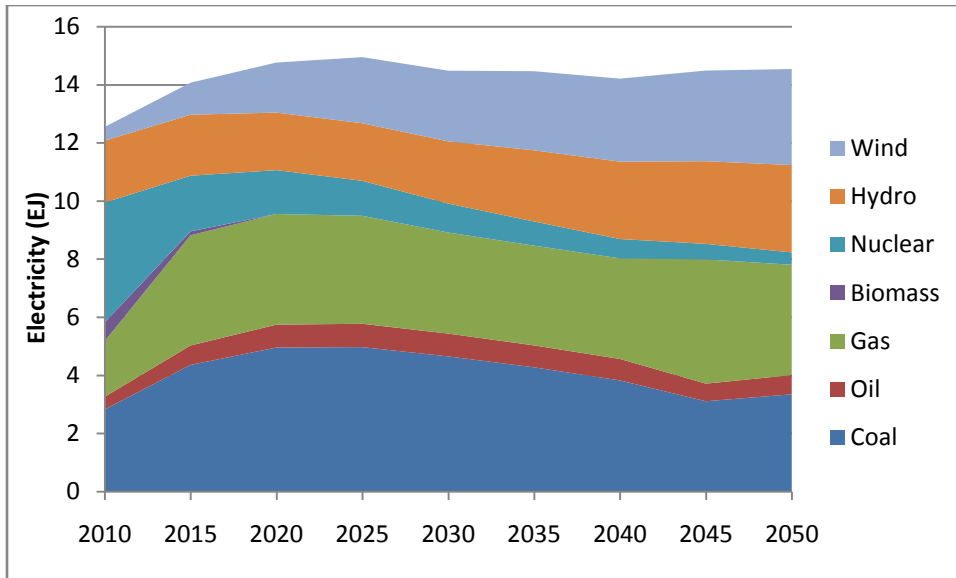


Figure 21 - Electricity generation with the Conventional wind approach at a 40% GHG reduction scenario by 2050 relative to 1990 levels

ii) New Approach :

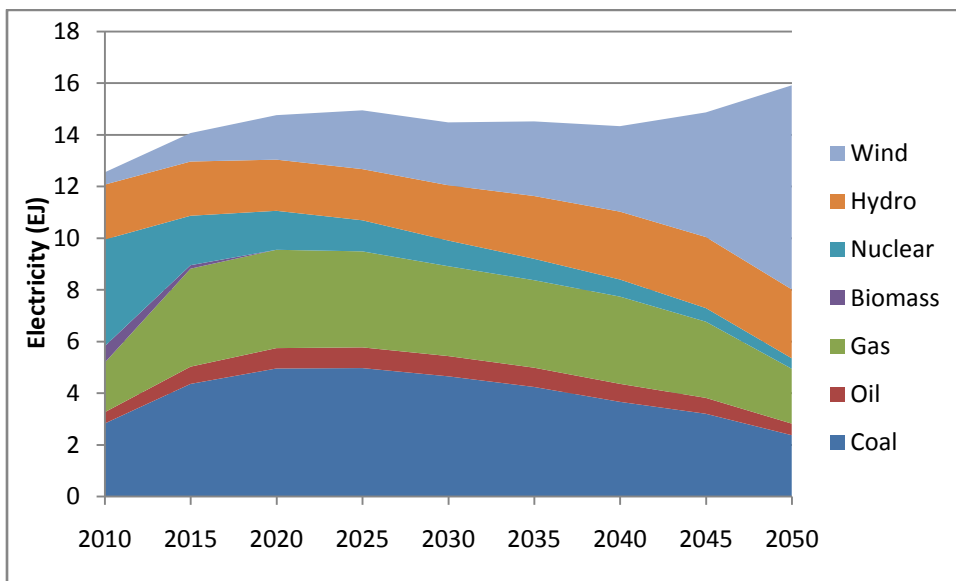


Figure 22 - Electricity generation with the New wind approach at a 40% GHG reduction scenario by 2050 relative to 1990 levels

In both approaches wind generation is increasing over the 40-year period. Hydro remains at relatively constant levels and nuclear is phased out by 2050. Fossil fuel technologies (coal, oil and gas) stay in the mix in the 40% GHG reduction scenario.

In the Conventional Approach (Figure 21) the wind entering the system is limited by the high cost of the windgas technology, which has a relatively high markup (Table 7) as a result of the 1-for-1 NGCC backup assumption. Wind penetration increases gradually over time, but wind does not dominate the power sector due to its limited competitiveness.

On the other hand, in the New Approach (Figure 22) wind is more aggressively displacing fossil fuel generation (both coal and gas). Because of the significant amount of both gas and hydro generation that is present in the system over the whole period studied, the system is flexible enough to accommodate a large amount of wind generation. In fact, it is observed that the flexibility constraints (Eq.10) associated with wind generation are not binding in this case. This means that the system would have the desired amount of flexibility anyway, even if these constraints did not exist.

In both approaches wind generation covers approximately 17% of total energy demand in 2030. However, this share stays around 22% in 2050 for the Conventional approach but significantly increases to 43% in 2050 for the New Approach.

An average electricity price across the European region in both approaches is shown in Figure 23:

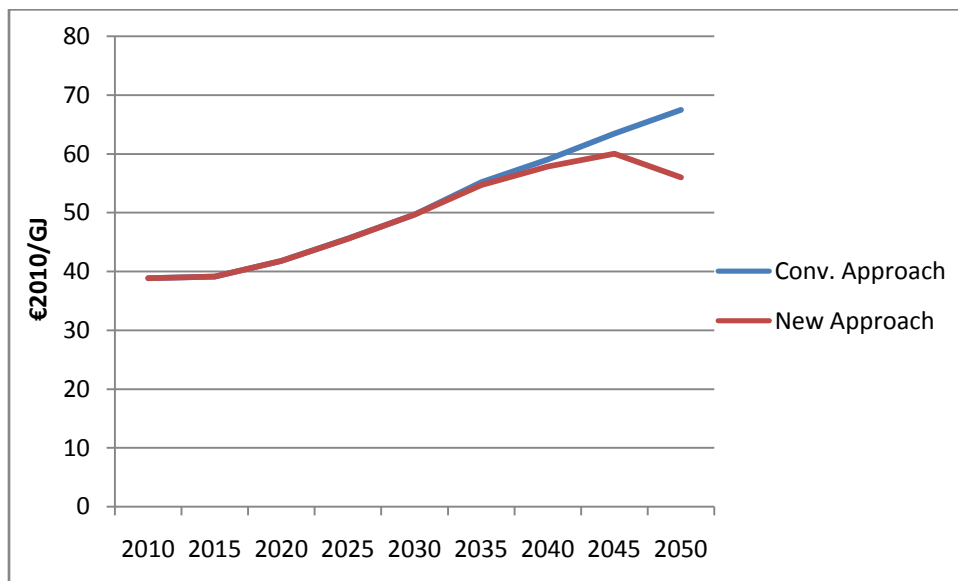


Figure 23 - Electricity Price for the two approaches at a 40% GHG reduction scenario

Over the first years modeled electricity price is growing and is the same for both approaches. After 2040, however, for the New Approach electricity price is growing at a lower rate, compared to the Conventional Approach, and is even dropping in 2050. This difference in price levels can be associated with the difference in generation mixes shown in Figures 21 and 22.

Particularly after 2040 the share of wind is much higher in the New Approach. Thus, wind covers a portion of the demand that would otherwise be covered by more expensive thermal plants with higher marginal cost of production (such as gas plants) and this is the main reason why electricity price remains at a relatively low level.

One way to measure an economy-wide impact of a policy is to look at macroeconomic consumption levels. The change in consumption as a result of a policy is often used for measuring the cost of that particular policy. Changes in electricity costs propagate through the entire economy. Differences in costing intermittency result in different macroeconomic costs. Figure 24 illustrates the absolute difference in consumption levels for the two approaches (Conventional and New), for the 40% reduction scenario.

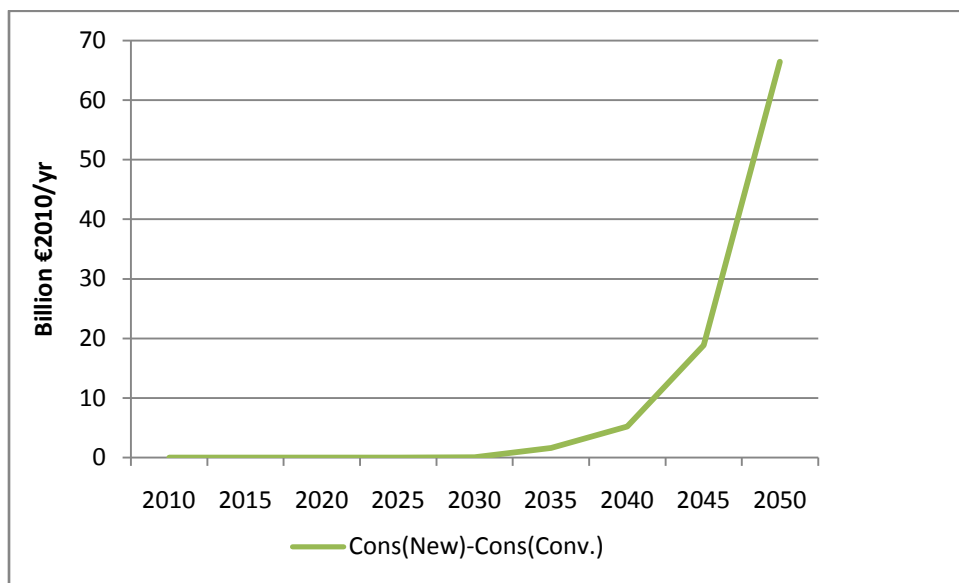


Figure 24 - Difference in Consumption levels between the New Approach and the Conventional one at a 40% GHG reduction scenario

Up to 2030, consumption levels are about the same for the two approaches. In 2040, consumption is higher by 5 billion €2010 in the New Approach, compared to the Conventional one, while this difference amounts to 65 billion €2010 in 2050. In relative terms, this corresponds to a 0.05% difference in consumption in 2040 and a 0.45% difference in 2050 respectively.

The total cost of a policy depends on various factors, such as future GDP growth, existing policies, technology costs, the scenario that is used as a baseline for comparing consumption levels, and others (for additional discussion, see Knopf et al., 2013). For the 40% GHG reduction scenario, an estimate of the total policy cost (including other measures not directly related to renewables target) can be obtained from the European EMF28 project in which the MIT EPPA

model participated (Knopf et al. 2013). The cost of the 40% GHG reduction policy relative to the No Policy case was estimated to be 180 billion €2010 in 2040 and 400 billion €2010 in 2050. Different approaches to model intermittent renewables can affect the total cost of the policy related to GHG mitigation.

5.1.2 Scenario II - 80% GHG Reduction by 2050

In this scenario an 80% GHG reduction target by 2050 is modeled, in alignment with what is proposed in the EU Energy Roadmap 2050 (EC 2011). Figures 25, 26 and 27 present the resulting generation mix for three approaches:

(i) the Conventional Approach, (ii) the Conventional Approach with updated markup for the windgas technology, as suggested by the bottom-up model results shown in Table 6, and (iii) the New Approach.

i) Conventional Approach:

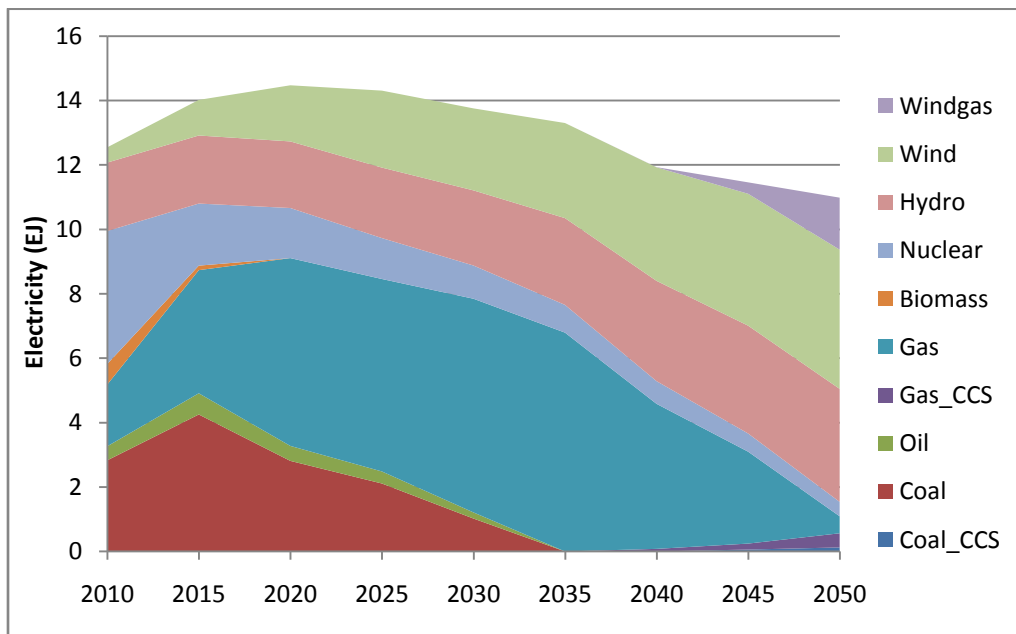


Figure 25 - Electricity generation with the Conventional approach at an 80% GHG reduction scenario by 2050 relative to 1990 levels

ii) Conventional Approach with updated Windgas markup:

A scenario with a lower markup for the windgas technology is also considered, as suggested by the bottom-up model results (Table 6).

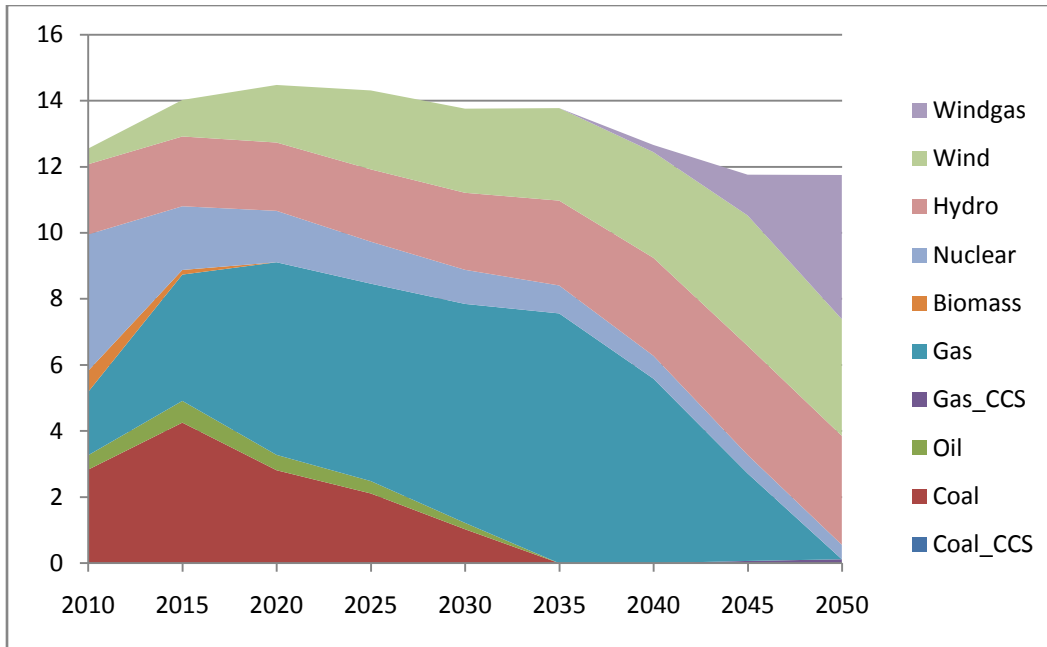


Figure 26 - Electricity generation with the Conventional EPPA Approach with improved windgas markup value for the 80% GHG reduction scenario

iii) New Approach:

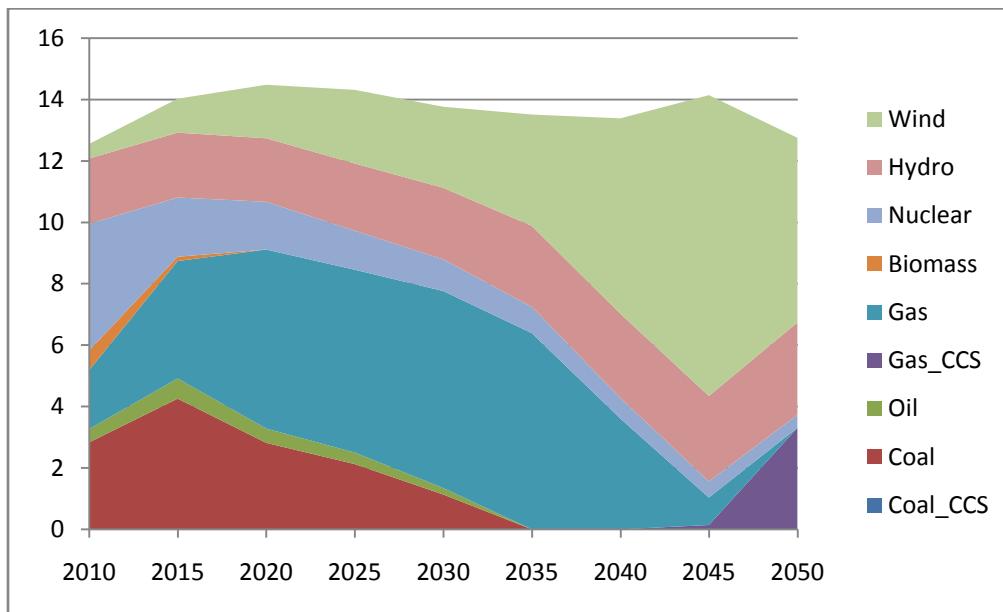


Figure 27 - Electricity generation with the New EPPA approach at an 80% GHG reduction scenario by 2050 relative to 1990 levels

In the Conventional approach (Figure 25), "windgas" technology is relatively expensive and thus, it enters only to a very limited extent after 2040, even with an 80% GHG reduction target, which requires very substantial decarbonization. The high markup of the technology as well as

the high price of natural gas in Europe are two reasons for that. Overall, wind penetration (wind and windgas) is increasing over the period studied, though at a high cost (see also electricity prices in Figure 29), leading to a decrease in overall electricity demand towards 2050.

Regarding the rest of the technologies, coal and oil are removed from the mix by 2035. Natural gas penetration peaking in 2035, at which point it meets the largest share of the demand. Towards 2050, generation from natural gas plants without CCS becomes almost zero while gas plants with CCS (and some coal plants with CCS) appear in the mix. Hydro generation remains approximately constant over the whole period, explained by the fact that the largest part of hydro capacity in Europe is already being exploited. Nuclear has been assumed to be phased out in most European regions by 2050.

As expected, when windgas markup is reduced (Figure 26), windgas becomes more competitive and enters the mix at higher levels. CCS technologies almost disappear from the mix in this case, as they are no longer necessary for meeting the emissions target, and demand does not drop as much as before (Figure 25).

When system flexibility requirements are modeled (Figure 27) more wind is introduced into the power generation. After 2045, however, increase in wind penetration slows down. What mainly causes the decrease in the penetration level of wind is the higher cost of the additional flexible backup capacity that is needed in the system. In an 80% GHG reduction scenario, gas generation - that would be a natural candidate for providing backup - is gradually phased out because of its carbon content, so that the emissions targets are met. Hydro - that would be a second candidate - has limited resource and its capacity increases only slightly through 2050. Biomass electricity - a potentially third candidate for providing flexible capacity - is also not considered here. Thus, more expensive technologies such as gas with CCS enter in order to satisfy the backup requirements of the system. Both because CCS is expensive and because it has a limited growth rate (as it is a new technology), the cost-minimizing solution given by the model for an 80% GHG emissions reduction case is to limit wind penetration after 2045.

Directly comparing wind penetration levels in Figure 25, Figure 26 and Figure 27 would be misleading, however, because in these three cases the resulting electricity demand is different. As has already been discussed, the emission constraints imposed lead to a very high electricity price in the first two cases (Conventional approach, see also Figure 29 below) and, as a result, at the welfare maximizing solution a drop in electricity demand is observed. This does not happen in the New Approach.

Of course, it should be stressed here that other options for mitigating wind intermittency, such as storage or demand response, have not been considered in this analysis. In reality, if these options are also available introduction of very expensive technologies, such as CCS technologies, just for

providing the required system backup will be avoided and cheaper storage or demand response options will be adopted.

In both Scenario I and Scenario II, nuclear has been assumed to be almost phased out by 2050. In fact, after the Fukushima nuclear accident many European countries revised their nuclear policies. As shown in Figure 28, in some cases such as Germany and Italy a complete phase out of nuclear generation has been decided. In other cases such as France, Spain and the UK construction of nuclear plants has not been significantly affected. Overall, the future role of nuclear in the EU is still uncertain so, a sensitivity case with nuclear preserving its generation share has also been considered in the following paragraph.

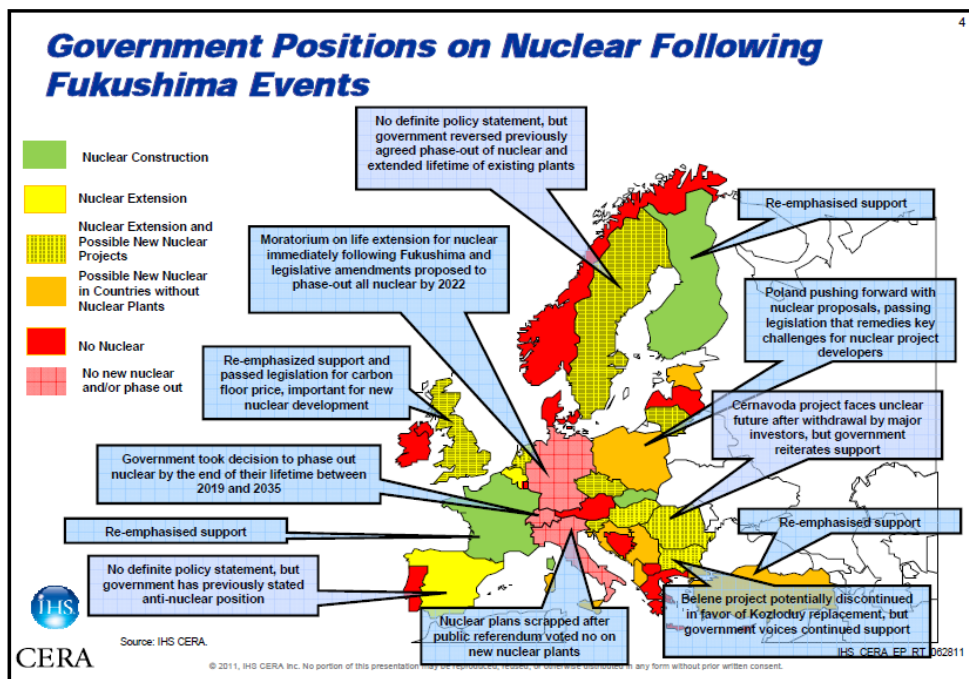


Figure 28 - Government positions on nuclear following Fukushima events (Source: IHS CERA 2011)

Figure 29 and Figure 30 provide a comparison of electricity prices and consumption levels for the 80% GHG reduction case and for the two approaches (Conventional and New) modeled:

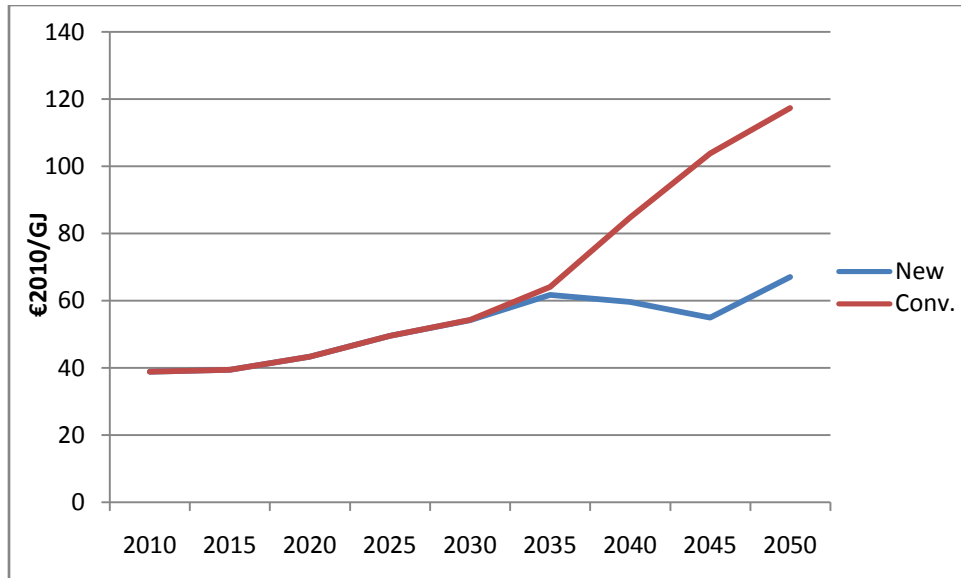


Figure 29 - Electricity Price for the two approaches at an 80% GHG reduction scenario

The price is again an average electricity price for the European region. The two approaches result in about the same price until 2035. After that point prices diverge. Electricity is much cheaper in the New Approach because of the large amount of wind that is gradually displacing more expensive technologies. A slight increase in price is observed after 2045 when CCS is entering in the mix.

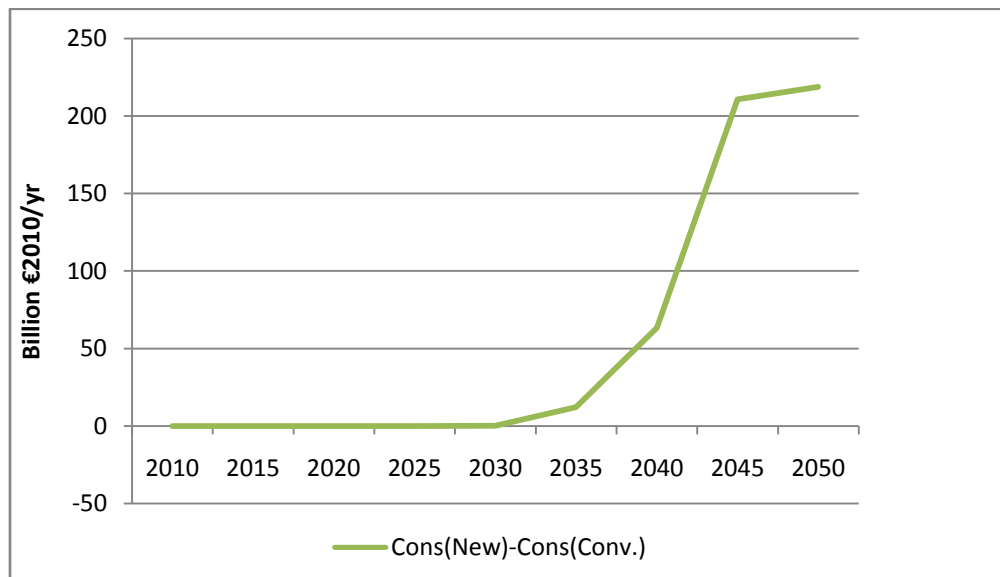


Figure 30 - Difference in Consumption levels between the New Approach and the Conventional one at a 80% GHG reduction scenario

The cost of the 80% GHG reduction policy - as given by consumption levels - is lower under the New Approach. In particular, as Figure 30 illustrates, consumption in the two approaches remains about the same up to 2030. In 2040 the New Approach results in higher total macroeconomic consumption in the EU by 70 billion €2010 compared to the Conventional Approach (or 0.6% higher relative to the Conventional Approach), while this difference becomes 200 billion €2010 in 2050 (or 1.7% higher in the New Approach, in relative terms).

The higher consumption levels in the New Approach are associated with the lower cost of integrating large amounts of wind generation - compared to the Conventional Approach - which allows meeting the emissions targets with a lower penalty in consumption. Comparing consumption levels in the 80% GHG reduction scenario with those in the 40% GHG reduction scenario, an estimate of the relative cost of the two policies can be obtained. In particular, the 80% reduction policy costs 310 billion €2010 more than the 40% reduction policy in 2040 and 980 billion €2010 more in 2050 for the New Approach.

Another interesting observation is that at an 80% GHG emissions reduction scenario the power sector is the first and only sector to be completely decarbonized. The rest of the sectors (Industry, Agriculture, Commercial, Residential and Transportation) reduce their emissions, as well, but to a smaller extent (Figure 31). This means that the power sector provides the "cheapest" way for reducing emissions relative to reduction in other sectors.

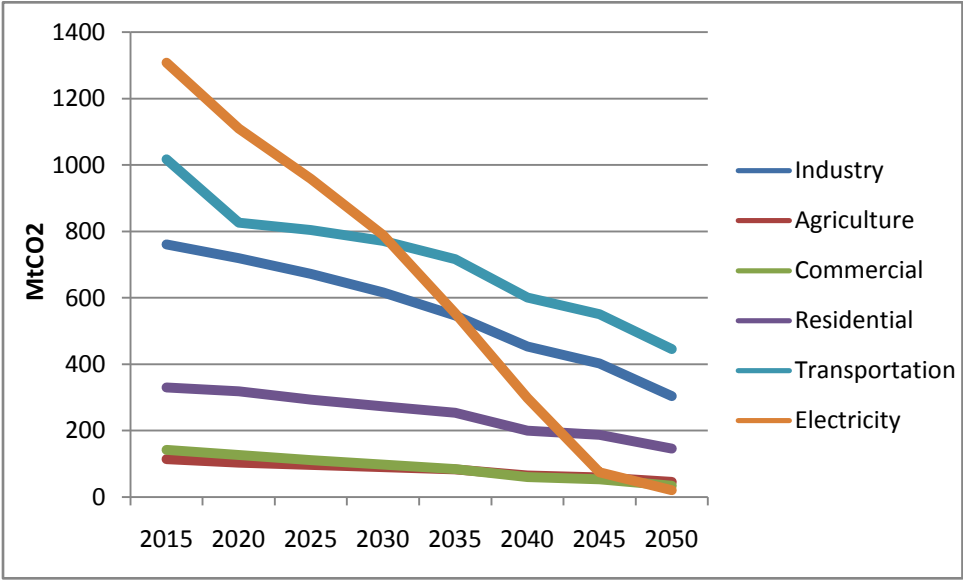


Figure 31 - CO2 emissions per sector in the 80% GHG reduction scenario (New Approach)

5.1.3 Sensitivity Analysis

Lower Flexibility Requirements:

A scenario with lower system flexibility requirements at large wind penetrations is modeled (Figure 32). In this case, wind is growing over the whole 40-year period studied. Comparing the resulting mix with the mix in Figure 27 - in which the flexibility requirement figures estimated from the bottom-up electricity model were used - it is apparent that the increased requirement for system flexibility at large wind penetration levels is the main factor that limits wind penetration in 2050 in Figure 27. In Figure 32 below, hydro generation can provide the required system flexibility and only a small amount of gas with CCS is entering after 2045.

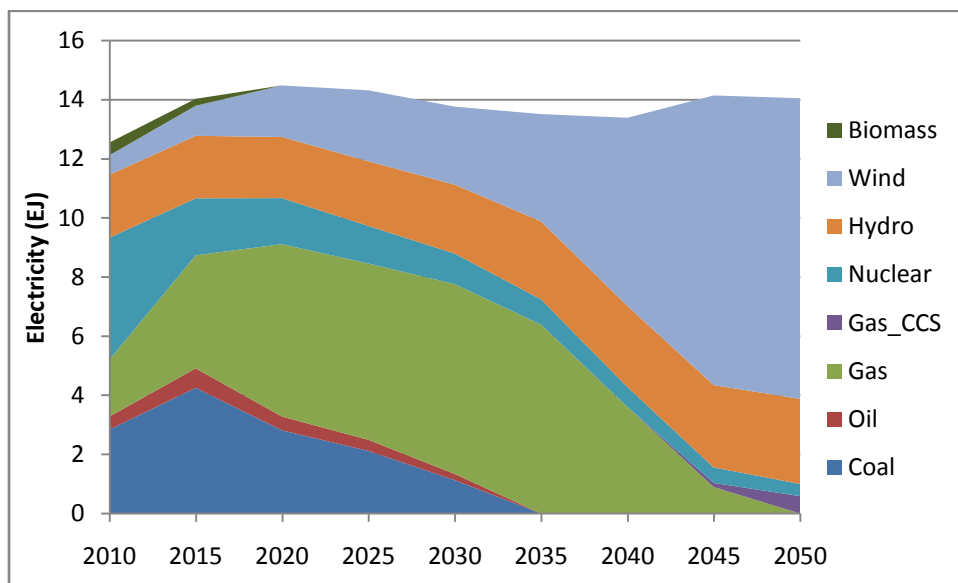


Figure 32 - Electricity generation with the New EPPA approach with low flexibility requirements at an 80% GHG reduction scenario by 2050 relative to 1990 levels

Wind penetration levels will also depend on the existence in the mix of other technologies that could interact with wind by providing or not providing flexible system backup, such as CCS or nuclear plants. In order to take into account the uncertainty in the deployment and evolution of these technologies a sensitivity analysis is conducted regarding the cost of CCS and nuclear generation phase-out.

Lower Cost of CCS:

Currently, the cost of CCS technologies remains high and a lack of progress is observed in large-scale CCS projects deployment. To scale up CCS, dedicated government funding and a broad carbon policy must be supported by a long-term strategy for CCS deployment and enabling

regulatory frameworks (IEA 2012). Given the uncertainty regarding the future CCS cost, two additional scenarios are considered for the 80% GHG reduction case; an optimistic scenario - with CCS costs that are comparable with current coal and gas generation costs and a low CCS cost scenario like in the MIT Future of Coal (2007) study. For the CCS optimistic scenario the resulting generation mix is shown in Figure 33. Current studies do not show such low CCS costs, this scenario is rather provided here to show the impact of very-low cost low-carbon technology in the mix that co-exists with wind generation.

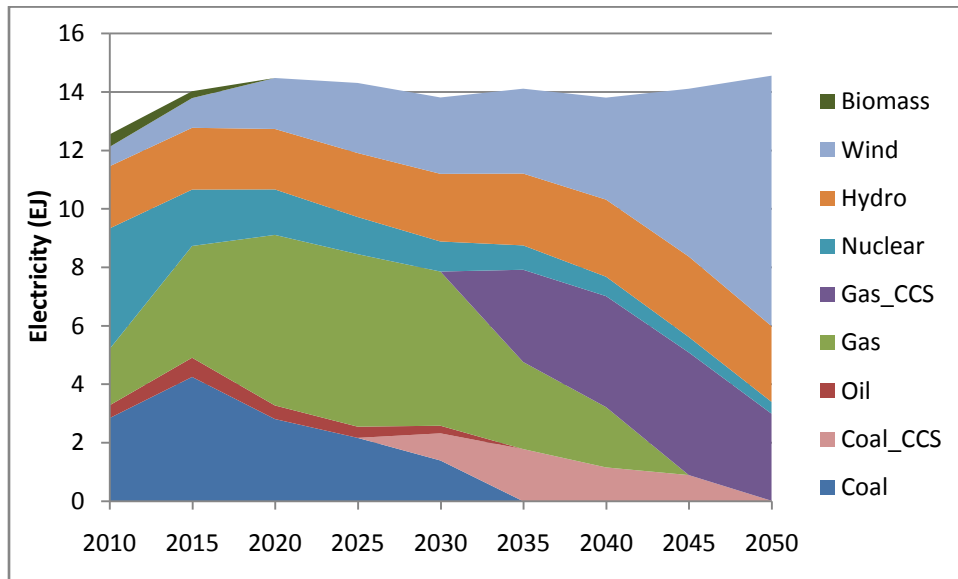


Figure 33 - Electricity generation with the New EPPA approach for optimistic CCS Cost at an 80% GHG reduction scenario by 2050 relative to 1990 levels

For optimistic CCS cost, CCS technologies are used for providing the required system backup and thus again, wind penetration is not restricted as was the case in Figure 27 and electricity demand does not decrease towards 2050. According to Figure 33, fossil fuel technologies without CCS are gradually removed from the mix - coal and oil by 2035 and NGCC by 2045. Coal with CCS enters in 2025 and gas with CCS in 2030 and they both grow over the following years. Gas with CCS reaches significant penetration levels by 2050. Wind is the dominant generation technology after 2045, covering more than half of the demand. Thus, for the 80% GHG reduction scenario, in the presence of a dispatchable, low-emission (or no-emission) technology that can provide flexible backup capacity at a reasonable cost, wind generation can reach significant penetration levels. Of course, this technology or combination of technologies might change for different periods and different regions depending on the trade-off between the LCOE of the available technologies, their flexibility and their emission levels. In other scenarios (not shown here) biomass technology was considered and this was the technology that mainly entered the mix for providing flexible system backup in later periods instead of CCS.

Another low CCS cost was also modeled (Figure 34) to show a development of power sectors if projections from MIT Future of Coal study about CCS costs are adopted. This scenario is a middle ground between Figure 27 and Figure 33 in terms of CCS cost. Here, gas with CCS enters in 2040 and grows until 2050. Again, however, wind penetration is limited in the last period as a result of the system flexibility requirement constraints. As the cost of CCS is higher than in the “CCS optimistic” scenario above, an increase in electricity price leads to a slight decrease in electricity demand from 2045 to 2050.

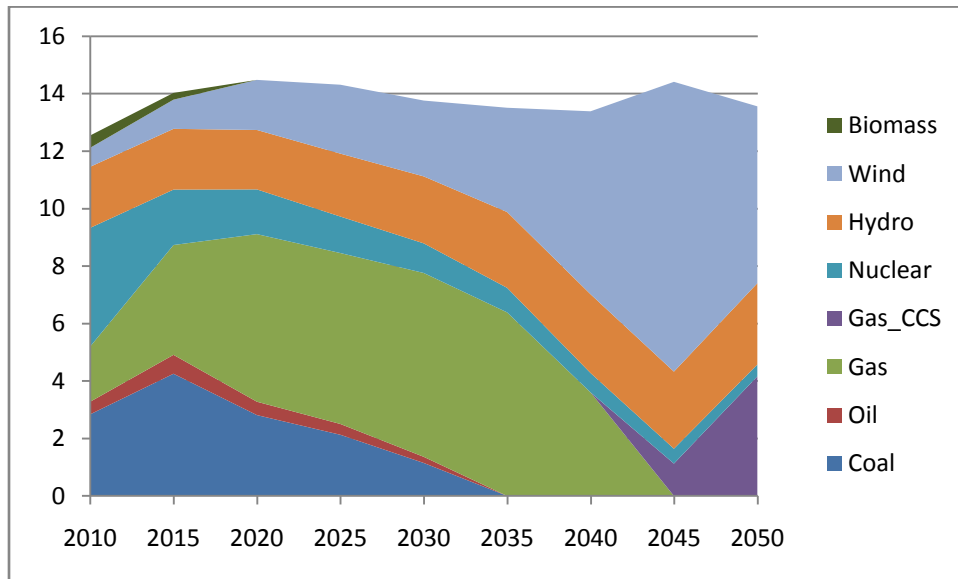


Figure 34 - Electricity generation with the New EPPA approach with low CCS Cost at an 80% GHG reduction scenario by 2050 relative to 1990 levels

Nuclear:

A sensitivity scenario in which nuclear generation preserves its current share in the mix is also considered:

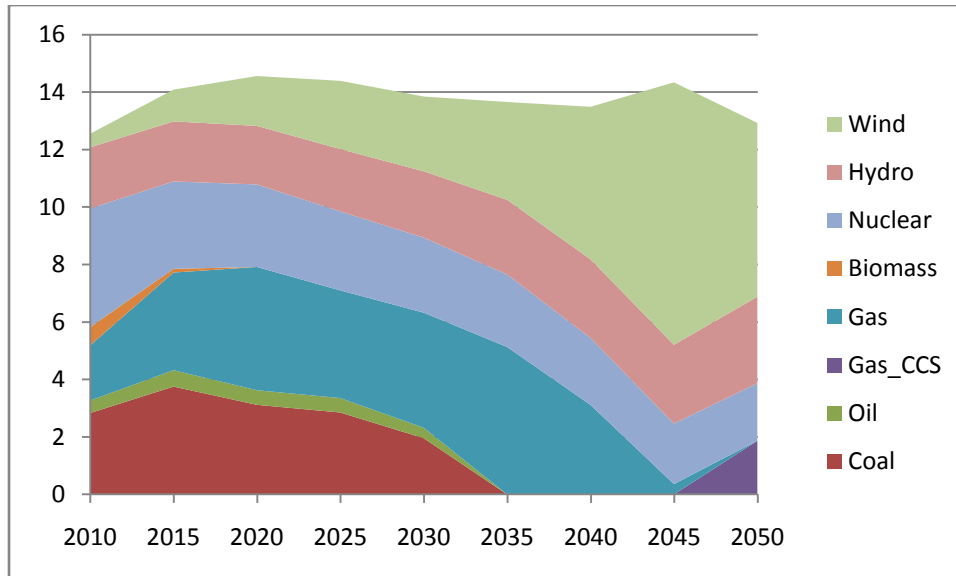


Figure 35 - Electricity generation with the New EPPA approach with Nuclear almost preserving its generation share for an 80% GHG reduction scenario

The resulting mix appears in Figure 35 and is similar to that in Figure 27. Wind in the system is gradually increasing, reaching a penetration level of around 50% in 2045. Nuclear generation, which covers a significant portion of demand (around 19% in 2030 and 15% in 2045) cannot provide the flexible backup generation required in the system for a large wind penetration. Because of the 80% emissions reduction constraint, NGCC plants without CCS do not provide this flexible capacity either. Instead, gas with CCS is entering in 2045 but it is a new and expensive technology that does not grow fast enough. As a result, in the absence of other relatively low-cost technological options for providing the required flexibility, wind generation is restricted in the last period, followed by a decrease in overall electricity demand.

6 Conclusions

In this work a comprehensive analysis of the implications of a large wind penetration on the power sector was conducted . Both the economic and the engineering implications were studied. In order to understand and capture the unique characteristics of wind generation it was recognized that different tools and methods would need to be combined to consider both economy-wind impacts and technological details.

The focus of this study is on Europe, even though many of the qualitative results of this analysis can be applied to other regions. The main reason for focusing on the EU is that wind generation is expected to play an important role in meeting long-term European GHG reduction targets, but also the fact that there is currently a lot of debate on the energy and climate policies that should be implemented in the region after 2020.

First, an analysis of hourly wind and load profiles was conducted for single European countries and for the whole European region. Then, a detailed electricity model was used in order to capture the effects on the system of a large wind penetration (up to 60% of total demand). Finally, this information was integrated in a computable general equilibrium (CGE) model, the MIT EPPA model - a commonly used tool for analyzing the economy-wide implications of energy and climate policies. Based on the bottom-up modeling results, a new methodology was proposed for capturing wind intermittency in the EPPA model, on the basis that the system needs to have a minimum amount of flexible technologies installed in order to accommodate large wind penetration levels. As a case study, a 40% and an 80% GHG emissions reduction scenario by 2050 (relative to 1990) levels were modeled for Europe using EPPA.

The outcomes of this work have various implications for energy policy analysis and are described next.

6.1 Outcomes and Policy Implications

The following conclusions can be drawn from the analysis:

- The effects of introducing a large amount of wind generation in a system are region-specific. They depend on factors such as the wind resource, the hourly wind and load profile and the initial generation mix in the system. However, some general observations can be made:

- An increasing share of wind in the system requires an increasing amount of system flexibility. On the supply side, this flexibility will mainly be provided by gas technologies, such as gas turbines or combined cycle gas plants. Hydro plants could also be used for this purpose, even though in Europe and in most developed countries there is not a lot of hydro capacity left to be exploited.
- Up to a certain wind penetration level, peaking gas turbines will be providing the flexible backup capacity required in the system.
- At higher penetration levels, however, a switch to combined cycle gas plants for providing the necessary flexibility is observed. The reason is that: the higher the wind penetration in the system, the more hours flexible gas plants need to operate. Thus, combined cycle plants that have lower operating costs than gas turbines become economical.
- Particularly in Europe, it was found that wind generation will play an important role in achieving GHG emission targets both in a 40% and in an 80% GHG emissions reduction scenario.
- However, when flexibility constraints are introduced and for an 80% GHG emissions reduction scenario, integrating a very large amount of wind in the system becomes challenging.
- An overall 80% GHG emissions reduction target by 2050 leads to a complete (or almost complete) de-carbonization of the EU power sector. Emissions from the rest of the sectors will also be reduced but none of them will be completely decarbonized by 2050.
- In such a low-emission environment, the ability of gas plants to provide flexible backup capacity is limited and other low-carbon technologies need to be used instead (including hydro, biomass or CCS plants).
- Unless low-carbon, flexible technologies are available at a reasonable cost, a large wind penetration may not be compatible with an overall 80% GHG emissions reduction target. Stated differently, a very high wind penetration will need to be accompanied by the existence of flexible technologies in the system. If these technologies are not available at a competitive cost then, significant amounts of wind generation will not be the least-cost solution for achieving the 80% GHG reduction target.
- However, flexibility can also be provided by other options not considered here, such as Demand Response, Storage or Interconnections. In particular, analysis of wind and load

time series both for single European countries and for Europe as a whole showed the value of interconnecting wind farms across the continent. Both the capacity credit of wind and other indices of wind variability, such as the Coefficient of Variation show improved values when the European region is aggregated. Taking advantage of these alternative options for providing system flexibility and combining them with a flexible generation mix will enable a significant amount of intermittent generation to be introduced in the system, without compromising its reliable operation.

- Finally, the level of wind penetration will be affected not only by the cost of wind technology itself but also by the costs and policy decisions associated with other generation technologies, such as nuclear or CCS technologies.

Therefore, efforts to integrate large amounts of wind in a system should take into account the ability of the system to provide flexible operation. When imposing significant emission reduction targets policy-makers should ensure that there are low-emission technologies that can provide this flexibility at relatively low cost. R&D spending or regulatory support for such technologies might need to be considered. Also, other options for providing system flexibility, such as demand response, energy storage or interconnections will need to be implemented.

For researchers working on energy policy modeling tools, studying the impacts of policies involving large amounts of wind will be challenging. For a comprehensive analysis at various timescales, different modeling tools and methods traditionally considered separately will need to be integrated. Detailed electricity models (e.g. unit commitment models), including hourly information, will need to be combined with economy-wide models, capturing broader economic interactions, as well as with analysis of wind and load profiles that reveal the region-specific value of wind resource.

6.2 Future Work

In this work, bottom-up detail was introduced in the power sector representation of a top-down Computable General Equilibrium model. The main motivation was to capture the effects of wind intermittency on the system that will become more important with an increasing wind penetration. There is, however, plenty of room for additional research in this area. For example:

- It was assumed that flexibility in the system can only be provided by flexible generation technologies. Yet, in an 80% GHG reduction scenario there will probably be limited low-carbon technologies that can play this role. It is important that additional flexibility options are considered in a future work, such as storage, demand response or interconnections.

- Also, the approach that has been suggested for capturing flexibility requirements has been implemented for wind but could be generalized for all generation technologies. This would result in more accurately capturing power sector interactions in the EPPA model.
- In addition, a methodology for quantifying system flexibility requirements at different wind penetration levels, as well as comparing and quantifying the amount of flexibility "provided" by different technologies, was proposed in this work. However, this is an area that should be researched more.
- Other intermittent renewables, such as solar power, could also be studied in a similar way as wind, and their interactions with wind generation could be considered. In fact, the co-existence of wind and solar sources in a system may reduce the effects of wind intermittency if their generation is complementary (Agelidis et al. 2009). For instance, in many regions solar generation peaks in the summer or during the day while wind generation peaks in winter or during the night. Another study by Sinden (2002) found that requirements for system backup capacity for a large wind penetration level could be reduced by almost two thirds if the same amount of electricity is produced by a portfolio of renewable energy technologies rather than by wind power alone.
- Another improvement can be the use of different load segments in the EPPA model. This approach has been implemented in a version of EPPA and is described in McFarland et al. (2008). However, it could be further improved to include more technologies, such as nuclear, hydro or intermittent renewables. Each technology can be required to generate in one or more of these load segments, depending on its flexibility profile.

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