Economic Modeling of Intermittency in Wind Power Generation

by

Alan Yung Chen Cheng

A.B., Engineering Sciences Modified with Environmental Policy – Dartmouth College, 2003
B.E., Environmental Engineering – Dartmouth Thayer School of Engineering, 2003

Submitted to the Engineering Systems Division and
the Department of Civil and Environmental Engineering
in partial fulfillment of the requirements for the degrees of

Master of Science in Technology and Policy
and Master of Science in Civil and Environmental Engineering

at the
Massachusetts Institute of Technology
June 2005

Signature of Author ______________________________
Engineering Systems Division and
Department of Civil and Environmental Engineering
May 13, 2005

Certified by ______________________________
Henry D. Jacoby
Co-Director, MIT Joint Program on the Science and Policy of Global Change
Professor, Sloan School of Management
Thesis Supervisor

Certified by ______________________________
David H. Marks
Morton and Claire Goulder Family Professor of Civil and Environmental Engineering & Engineering Systems
Director, Laboratory for Energy and the Environment
Thesis Reader

Accepted by ______________________________
Andrew J. Whittle
Professor of Civil and Environmental Engineering
Chairman, Departmental Committee for Graduate Students

Accepted by ______________________________
Dava J. Newman
Professor of Aeronautics and Astronautics and Engineering Systems
Director, Technology and Policy Program

Economic Modeling of Intermittency in Wind Power Generation

by

Alan Yung Chen Cheng

Submitted to the Engineering Systems Division and
the Department of Civil and Environmental Engineering on May 13, 2005

in partial fulfillment of the requirements for
the Degrees of Master of Science in Technology and Policy and
Master of Science in Civil and Environmental Engineering

Abstract:

The electricity sector is a major source of carbon dioxide emissions that contribute to global climate change. Over the past decade wind energy has steadily emerged as a potential source for large-scale, low carbon energy. As wind power generation increases around the world, there is increasing interest in the impacts of adding intermittent power to the electricity grid and the potential costs of compensating for the intermittency.

The goal of this thesis research is to assess the costs and potential of wind power as a greenhouse gas abatement option for electricity generation. Qualitative and quantitative analysis methods are used to evaluate the challenges involved in integrating intermittent generation into the electricity sector.

A computable generation equilibrium model was developed to explicitly account for the impacts of increasing wind penetration on the capacity value given to wind. The model also accounts for the impacts of wind quality and geographic diversity on electricity generation, and the impacts of learning-by-doing on the total cost of production. We notice that the rising costs associated of intermittency will limit the ability of wind to take a large share of the electricity market. As wind penetration increases, a greater cost is imposed on the wind generator in order to compensate for the intermittency impacts, making the total cost from energy from wind more expensive. Because the model explicitly accounts for the impacts of intermittency, the decision to add wind power to the grid is based on the marginal cost of adding additional intermittent sources to the system in addition to the cost of generating wind energy

This model was incorporated into the MIT Emissions Prediction and Policy Analysis model in order to analyze the adoption of wind technology under three policy scenarios. In a business as usual scenario with no wind subsidies or carbon constraints, wind energy generation rises to 0.80 trillion KWh in 2090 and accounts for 9% of the total electricity generation. In a scenario that stabilized greenhouse gases at 550 parts per million, high carbon penalties motivate the entry of 1.16 trillion KWh of wind energy generation in 2055 that accounts for 22% of the total electricity generation. With a production tax credit subsidy for wind generation, wind energy generation increases by average of 12% over the base case scenario during the years the policy was in effect. However, when the subsidy tapers off, wind generation in later periods remains unchanged.

Thesis Supervisor: Henry D. Jacoby
Co-Director, MIT Joint Program on the Science and Policy of Global Change

Acknowledgements:

I would like to begin by acknowledging my research supervisor and mentor Professor Jake Jacoby. His constant support of my research endeavors, and unwavering confidence in me and in this research topic, have been key contributors to my success as a graduate student as well as to the success of this thesis. His passion for the research and his sense of balance in work and life has made the past several years enjoyable both professionally and personally.

My work here at MIT is constantly shaped by my interaction with the Joint Program on the Science and Policy of Global Change. I wish to thank all of the faculty, staff and students of the Program for providing a supportive, interactive and dynamic research environment. In particular, I wish to thank Sergey Paltsev and Jim McFarland for always leaving their doors open and always guiding me as I made my way through the EPPA model. I would not have made it without your help. Therese, thank you for always looking after me. I could not have possibly asked for more. Professors Bill Nuttall and David Reiner, thank you for so warmly welcoming me to England. The opportunities I had at the University of Cambridge have not only help my research here but have also inspired me to teach and to grow as an educator.

One of the wonderful aspects of MIT is the incredibly brilliant and dedicated students it attracts. My fellow graduate students at the Joint Program and at TPP have been my friends, colleagues and teachers at the same time. Travis, Kira, Dulles, Ram, (and Misha), thank you for the intellectual inspiration and for the comic relief.

In closing, I would like to thank my family for their continuing support. It has not been easy; moving to a new country, picking up a foreign language and starting new professions. I cannot thank them enough for the many sacrifices they made along the way. I know it was a dream of theirs for me to graduate from MIT. I hope that my next stage in life will make them just as proud.

Table of Contents:

Table of Figures:

CHAPTER 1: Introduction and Background

1 Introduction

The electricity sector is a major source of the carbon dioxide emissions that contribute to global climate change. In the United States, electricity generators fired by fossil fuels are responsible for roughly 40% of all human carbon dioxide emissions (EIA, 2004). Potential climate impacts, coupled with the growing demand for electricity in both developed and developing countries, are motivating a shift towards less CO_2-intensive generation technologies. Switching a substantial fraction of U.S. electricity generating capacity from fossil fuels to renewable technologies such as geothermal, biomass, or wind-powered turbines would help to reduce carbon emissions from this sector. In addition to the reduced environmental impacts, energy from renewable resources increases our overall fuel diversity and lessens our dependence on fossil fuels. This diversification is particularly important because fossil fuels such as oil and gas are often subject to rapid price fluctuations and supply problems. Regrettably, after decades of development renewables remain a small share of existing electricity markets because of their relatively high cost.[1]

1.1 The Growth of Wind

Spurned by the massive oil crises in the 1970s, solar, wind and wave energy were hailed as nature's ultimate answer to our energy needs. They did not contribute to air pollution and were considered unlimited in supply. The US Department of Energy made significant investments to develop these renewable energy technologies. As it turned out, when concerns over oil security leveled off in the 1980s, research funding greatly diminished. Additionally, technological challenges and regulatory obstacles have made it difficult for renewable energies to compete with conventional technologies. As a result, the per kWh cost of solar energy is remains much too high to be competitive with traditional energy sources, and wave and tidal energy has not faired any better.[2]

Fortunately, out of the three technologies wind energy has taken off. Great strides have been made over the past two decades in improving the reliability, cost-effectiveness and overall understanding of wind energy. The global wind power industry installed 7,980 megawatts (MW) in 2004, resulting in a total installed generating capacity of 47,300 MW (GWEC, 2005). Penetration levels in the electricity sector have reached 20% in Denmark and about 5% in both Germany and Spain (GWEC, 2005). The north German state of Schleswig-Holstein has 1,800 MW of installed wind capacity, enough to meet 30%

---

[1] In the United States, solar, wind and geothermal sources account for less than 1% of total energy consumption (EIA, 2004).

[2] Because of limited experience with marine renewables, it is difficult to be certain how economic they will be if developed to a mature stage. There is also limited experience with tidal barrages; only one large-scale complex of this kind has been constructed to date at La Rance in France. Most marine energy is too diffuse and too far from where it is needed to be economically exploited (Fraenkel, 1999, UNDP-WEC, 2000).

of the region's total electricity demand, while in Navarra Spain 50% of electricity consumption is met by wind power.

With continuous improvements in efficiency and reductions in capital cost, the per kWh cost of wind energy has declined by approximately 8 percent per year throughout the 1990s (DWEA, 2003). Larger turbine sizes, lower costs, public policy support and bigger wind farms all have enabled wind capacity to grow at an average annual rate of 35 percent over the past several years (DWEA, 2003). However, in spite of these improvements, significant barriers remain which must be overcome before wind energy can achieve substantial adoption within the general electricity market. The most significant of which is the cost of production. The next section highlights some of the current policies that meant to lower the costs and incentivize wind energy generation.

1.2 Current Policies Affecting Wind

Under current production costs, wind is only economically competitive in a few niche markets. Much of the growth we have seen in recent years is due to favorable policies that have incentivized wind energy generation. As the industry grows it will continue to depend on these policies. In this section, I discuss some of the current policies in place that are intended to affect investments and growth in wind energy. First, I outline the three different types of wind incentive systems: fixed-price systems, fix-quantity systems and emissions trading schemes. Then I look at three different regions: the United States, the European Union and Japan, to see how these policies have been implemented and their preliminary successes and failures. Later in this thesis we will build off of this discussion and present the results from several "policy cases" that reflect what we may expect to see in the future.

1.2.1 Fixed price policies

Under fixed price policies government sets electricity prices, or some cases price premiums, paid to the power producer and the market determines the quantity of electricity produced. There are four general variations of policies: investment subsidies, feed-in tariffs, fixed premium systems and production subsidies. They are described below.

Investment Subsidies – These are subsidies for investment that are given on the basis of rated power. These were some of the first subsidies in place and did not take into consideration the actual plant productivity. As a result, many large wind farms got built regardless of whether they actually produced power. Recent subsidies have come in the form of production tax credits. These tax credits are not based on rated power but instead is given for actual electricity produced. An analysis of a production tax credit is presented in Chapter 4.

Fixed Feed-in Tariffs – Here, operators are paid a fixed price for every kWh of electricity they feed into the grid. The incentive is currently used in Germany where legislation fixes the price of electricity from renewable energy sources in relation to the generation costs of renewable technologies. It encourages advance planning because it is relatively straightforward.

Fixed Premium Systems – These systems are similar to the feed-in tariffs except in this case the government fixes a premium to be added to the electricity price. This premium is supposed to reflect the external costs of conventional power generation. In actuality, countries that pass the fixed premium legislation still base their premiums in a manner to offset the estimated renewable electricity production costs relative to conventional generation rather than on the actual environmental benefit.

Surcharge-Funded Production Subsidy – Under this approach, consumers pay a surcharge on all electricity purchases, and the revenue from the surcharge is distributed to renewable generators on a per-kilowatt-hour basis for each unit of electricity produced. The recipients of these payments and the level of the payments are determined in a periodic auction where the winners are those who bid the smallest increment of subsidy required per kilowatt-hour.

1.2.2 Fixed quantity policies

Under these policies the government sets the quantity of renewable electricity desired and leaves it to the market to determine how to meet those demands. The three main variations are renewable portfolio standards, tradable green certificates and tendering systems.

Renewable Portfolio Standards – These standards are requirements that a minimum percentage of the electricity produced or sold in the region must come from renewable sources, typically excluding hydroelectric facilities. A number national renewables portfolio standards ranging from 5% to 20% have been proposed for different countries. Some regions have implemented nonbinding generation targets for wholesale electricity suppliers.

Tradable Green Certificates – In an extension of the portfolio standards, generators under this system are obligated to supply a certain percentage of electricity from renewable energy sources. Retailers must purchase renewable certificates to show compliance with their obligation or else they are subject to a penalty for any shortfall. The prices are then settled on daily electricity market subject to meeting these minimum requirements. One possible complication with relying on this type of policy is that penetration of renewables becomes independent of the technical progress and the increasing efficiency of scale of the technology. Even if wind farms become marginally cheaper to install, it will be unlikely that the industry will want to install more to go beyond the minimum requirement.

Tendering System – This approach typically takes the form of a solicitation by a governmental energy agency, regulator, or regulated utility (under regulatory or legal requirement) for bids to supply a limited wind energy capacity in a given period. The power purchase agreements are usually for a 15 to 20 year period and the price is agreed upon a definite period, which removes political risk for the investors.

1.2.3 Emissions Trading Schemes

The Emissions Trading Scheme (ETS) is one of the key policies and measures developed under the European Climate Change Programme to ensure that the European Union and Member States limit or reduce emissions of climate-changing greenhouse gases in line with their commitments under the Kyoto Protocol. The EU greenhouse gas Emissions Trading Scheme began on 1 January 2005. The scheme is restricted to only one of the greenhouse gases – carbon dioxide – and to energy and industrial sectors. ETS lays the foundation for an electronic registry system that will keep track of the ownership of emission allowances as they change hands in the market. Under the system, emitters are set CO_2 limits and either pay a fine or buy permits from firms that undershoot their targets. The permit trading involves nearly 5,000 European companies within the industry and energy sector, which account for 46% of all EU carbon dioxide emissions.

The trading scheme will indirectly affect renewables in that ETS by itself will not guarantee that renewable targets will be reached as the policies only covers the greenhouse gas benefits of renewables. The philosophy behind emissions trading is that greenhouse gas reductions should be made at the lowest possible cost to society. With the lenient constraints, emissions trading will most likely have little impact on the profitability of investing in wind energy in the short term and it will have no impact on renewable energy technologies competitiveness vis-à-vis fossil fuel technologies. In the longer term, as the quotas are tightened (and/or free allocation is replaced by auctioning of allowances), and some of the "once-in-a-life-time" options, such as switching to gas and increasing efficiency, have been utilized, wind power and other renewable energy sources could benefit from a higher emissions allowance price and higher alternative abatement costs. An analysis of an emissions trading scheme that includes all greenhouse gases and its impacts on wind energy generation will be presented in Chapter 4.

1.2.4 Wind Policies in the United States

Here we begin to discuss the current policies in specific regions. In theory, one way to motivate a shift away from fossil fuels toward renewables would be to tax or cap carbon emissions from electricity generators. However, policy makers have not embraced carbon taxes as a means of controlling emission, and they are unlikely to be adopted in the United States. Even if a national carbon tax were adopted in the United States, it is likely to start out small and increase in size over time (Burtraw and Palmer, 2004). Similarly, aggregate emission caps coupled with emission trading are likely to start with modest reductions. The "slow, stop, reverse" approach to carbon mitigation has become a central tenet of U.S. policy debate. Modest emission reduction targets in the near term are expected to be met with modest substitution away from coal to expanded use of natural gas, with very small incentives for greater renewables use in the short run. Political preference for the go slow approach suggests that a policy aimed directly at increasing renewables may be necessary to realize any gains from learning-by-doing and to achieve substantial contributions from renewables, which will be necessary to achieve more substantial emission reduction goals in the long term.

Several approaches are currently being used or considered to promote the use of renewables for electricity generation in the United States. A number of states – including Connecticut, Maine, Nevada, Massachusetts, New Jersey, Iowa and Pennsylvania – have adopted renewables portfolio standards (RPS) but the wind adoption in these states (and in the US in general) have been modest (EIA, 2004). These states are highlighted below in Figure 1. A number of bills proposing national renewables portfolio standards ranging from 5% to 20% by different deadlines—ranging from 2010 to 2020—have been debated before the U.S. Congress in recent years, but none has been passed into law.

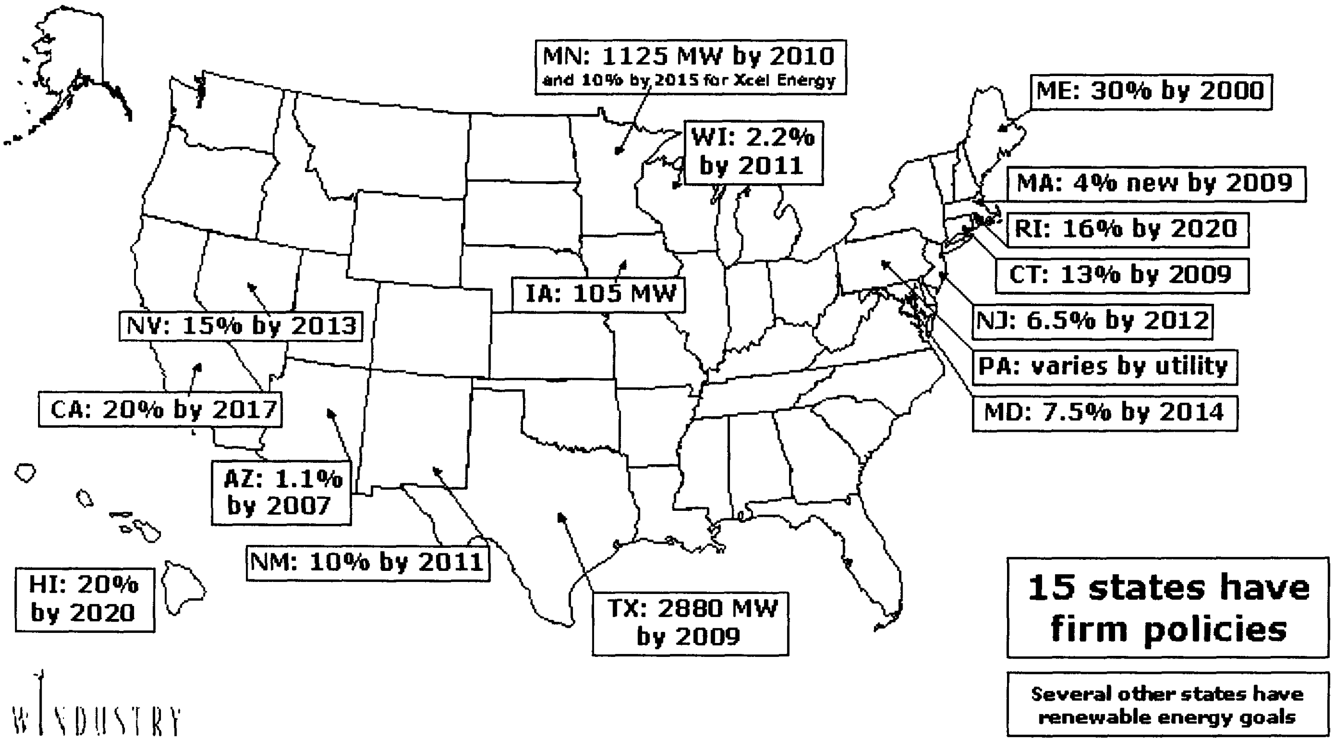


Figure 1 - Renewable Electricity Standards (WindIndustry, 2005)

The wind energy production tax credit (PTC), a per kilowatt-hour tax credit for wind-generated electricity, is another approach that has been popular at the federal and state levels (Burtraw and Palmer, 2004). Available during the first 10 years of operation, it provides 1.5 cents per kWh credit adjusted annually for inflation. The adjusted credit amount for 2004 is 1.8 cents per kWh. Enacted as part of the Energy Policy Act of 1992, the credit has gone through several cycles of expiration and renewal. In the latest round, the PTC expired at the end of 2003 and later was renewed retroactively through the end of 2005. The inconsistent nature of this tax credit has been a significant challenge for the wind industry, creating uncertainty for long term planning and preventing steady market development. Some states, such as California, have adopted another approach known as a surcharge-funded production subsidy. As described above, under this system consumers pay a surcharge on all electricity purchases, and the revenue from the surcharge is distributed to renewable generators on a per-kilowatt-hour basis for each unit of electricity produced.

1.2.5 Renewables Policies in the European Union

Renewable portfolio mandates are also becoming more popular in Europe. The European Union issued a Renewables Directive in October of 2001 that requires Member States to adopt national targets for renewables consistent with reaching the overall EU target that 12% of total energy and 22% of all electricity come from renewables by 2010. For the United Kingdom, the directive requires that 10% of total electricity consumption be generated using renewables by 2010.[3] The United Kingdom has decided to implement a tradable credit scheme to help in achieving this goal, moving away from a subsidy scheme that had been used earlier.

In addition to implementing a quantity-based approach, several countries in Europe and elsewhere also have used a price guarantee, often referred to as a feed-in tariff, to promote the use of renewables. Germany's initial feed-in tariff law was in effect from 1990 until 2000. The total amount of the tariff payment each year was based on utility average revenues, so the payments would fluctuate by year. The feed-in tariff approach has been successful in promoting wind energy; in 2000 a new feed-in tariff law took effect to help Germany achieve its goal of doubling renewables share from 6% to 12% by 2010. Under the new law, grid operators, instead of utilities, pay the feed-in tariffs and the level of the payment depends on renewable type.

The third major approach to promoting renewables used in Europe is the competitive tender offer or bidding system. However, this does result in complications related to investors "gaming" the system. Examples in the UK have shown that when contractors win the bid they often wait as long as possible to build, thus lowering the production costs (DWEA, 2003). This approach is currently implemented in Ireland, France, and the UK.

1.2.6 Renewables Policies in Japan

In Japan renewable electricity generation is covered by broader-based policies that have been adopted to promote a large category of underdeveloped energy resources, known as New Energy, throughout the economy. New Energy sources include most renewables, natural-gas-fired cogeneration, and fuel cells, but exclude hydro and geothermal. Currently, Japan has a target of achieving 3.1% of total primary energy supply from New Energy sources by 2010. According to the International Energy Agency, there are also targets for increased market penetration of specific renewable technologies in

[3] Different targets are set for different member states based on current renewable generation and potential resources available locally.

2010, including a 20-fold increase in wind capacity, a 14-fold increase in photovoltaic capacity, and a five-fold increase in biomass capacity.[4]

In 2002, Japan adopted the Special Measures Law Concerning the Use of New Energy by Electric Utilities. This law includes annual renewable penetration targets for electricity generators for the years between 2003 and 2010 and has a long-term goal of 1.35% of total electricity generation by 2010. The types of energy covered by this policy include solar, wind, biomass, small hydro, and geothermal.

The Japanese RPS policy is similar to those used in the United States and elsewhere. Electricity retailers are responsible for meeting the RPS, which will ramp up over time. Certified renewables producers receive credits for "Applicable Amounts of New Energy Electricity" that they can sell bundled with electricity-to-electricity retailers or trade separately on the renewables credit market. Renewables credits are bankable for up to one year and retailers are free to borrow up to 20% of their obligation in a current year from the subsequent year. Retailers who fail to comply with the renewables requirements will face penalties. However, there is a price cap of 11 yen per kWh on the price of renewables credits and retailers who cannot purchase credits for that price are exempt from fines (Keiko, 2003). Japan also has a national program to subsidize increased use of renewables by local governments and by small business, and a substantial program to support research and development into renewable technologies.

1.3 Dealing with Intermittency in Wind

Production cost limitations are further complicated by an additional challenge, intermittency. Wind power is generated only when the wind blows, and this intermittency is at the heart of many important wind integration issues and the focus of this thesis. Wind power is variable and thus not as easily scheduled or controlled as thermal, nuclear, fossil or hydroelectric generators. Even high-performing wind installations have relatively low annual capacity factors of between 20 and 40 percent (DWEA, 2003).[5]

Until recently, most of the world's wind power facilities consisted of one or two turbines interconnected with the local distribution network, but increasingly the growth in wind generation capacity is achieved through large wind farms interconnected to high voltage regional transmission systems. Small wind installations on low voltage networks have posed little or no threat to grid reliability. However, faced with the likelihood of substantial additional wind generation capacity to meet energy and environmental policy goals within the next ten years, many planners in major energy markets are

[4] See http://library.iea.org/dbtw-wpd/pamsdbre.aspx?id=90,accessed February 18, 2005.

[5] Although one would generally prefer to have a large capacity factor, it may not always be an economic advantage. In a very windy location, for instance, it may be an advantage to use a larger generator with the same rotor diameter This would tend to lower the capacity factor (using less of the capacity of a relatively larger generator), but it may mean a substantially larger annual production. To a certain extent you may have a choice between a relatively stable power output (close to the design limit of the generator) with a high capacity factor - or a high energy output (which will fluctuate) with a low capacity factor.

evaluating wind integration strategies to help ensure that their power systems also remain stable and reliable.

1.4 Outline of Thesis

The goal of this thesis research is to assess the costs and potential of wind power as a greenhouse gas abatement option for electricity generation. Qualitative and quantitative analysis methods are used to evaluate the challenges involved in integrating intermittent generation into the electricity sector.

This chapter gave an introduction to the topic and highlighted some of the current policies that impact wind energy investments and implementation. Chapter 2 introduces the challenge of integrating an intermittent power source to the electricity system. It starts with a discussion of utility power planning and system reliability and then moves onto valuing wind energy contributions. I look at some of the major questions regarding intermittency and the associated transmission and backup constraints and present findings from past research. I also describe how other models represent wind energy.

Chapter 3 proposes a new method of representing wind in a computable general equilibrium (CGE) model that takes into account the dynamic impacts of degrading wind resources and of rising wind penetration on the electricity market. Chapter 4 presents the results from the model. The first part shows a "business as usual" run of the model, in which no carbon policies or wind subsidies are applied. The second part evaluates the potential impacts and costs associated with implementing potential policies described above. I present the results from two policy scenarios: a 550 parts per million (ppm) greenhouse gas concentration stabilization scenario and a production tax credit scenario. Finally Chapter 5 concludes with some final thoughts on the policy implications and areas for future research.

CHAPTER 2: The Challenge of Coping with Intermittency

2 Introduction – Impacts of Integrating Wind

As the use of wind power increases around the world, there is increasing interest in the impacts of adding intermittent power to the grid. This is because wind power plants only generate electricity when the wind is blowing, and the plant output depends substantially on the wind speed.[6] Currently, wind often fluctuates from hour to hour and minute to minute and exact wind speeds cannot be predicted with high accuracy over daily periods. Consequently, electric utility system planners and operators have been concerned that variations in wind-plant output may increase the operating costs of the power system as a whole. This concern arises because the system must maintain an instantaneous balance at all times between the aggregate demand for electric power and the total power generated by all contributing power plants. In general, the costs associated with maintaining this balance are referred to as ancillary-services costs. The utility operators and automatic controls routinely perform this task based on well-known operating characteristics for conventional power plants and a great deal of experience accumulated over many years.

System operators have been concerned that variations in wind-plant output will force the conventional power plants to provide compensating variations in order to maintain system balance, thus causing the conventional power plants to deviate from operating points that have been chosen to minimize the total cost of operating the entire system. The operators' concerns are compounded by the fact that conventional power plants are generally under their control and thus are dispatchable, whereas wind plants are controlled instead by nature. While these are valid concerns, it is important to understand that the key issue is not whether a system with a significant amount of wind capacity can be operated reliably, but rather to what extent are the system operating costs increased by the variability of the wind.

The unique operating characteristics of the intermittent renewable technologies cause difficulties when evaluating intermittent energy resources against conventional options. Several key questions need to be addressed:

1. **Utility planning and system reliability:** How are the costs of operating the power system affected by the inclusion of wind power in the generation mix?
2. **Valuing wind energy contributions:** How can these cost impacts be evaluated? Do wind plants require backup with dispatchable generation, and if so, to what extent?
3. **Capacity value and penetration:** How do these cost impacts vary with wind power's penetration of the system generation mix and with variations in other key system characteristics like generation mix, fuel types and costs, and access to external markets for energy purchases and sales?

[6] The theoretical power from a wind turbine is a function of the wind speed cubed. Thus, a doubling of wind speed will result in an eight-fold increase in wind power.

4. **The role of storage:** Can storage increase the value of intermittent generation? What are the options and their costs?

The following four sections will address each of these questions individually.

2.1 Utility Power Planning and System Reliability

In order to value wind energy contributions we first need to examine the "rules of the game" that current utility planners take into account when deciding how to value capacity additions. Utility planners use one of several indices to evaluate system reliability: reserve margin (RM), loss-of-load-expectation (LOLE), loss-of-energy expectation (LOEE), and frequency and duration (F&D) index. By calculating how wind plants affect system reliability, we can evaluate the cost impacts of integrating those wind plants.

- **The reserve margin** is the generation reserve capacity expressed as a percentage of weather-normalized expected peak load. It is a static measurement of the system capacity adequacy and does not consider plant and fuel availabilities.
- **Loss of load expectation** (LOLE) is the basis for most methods of assessing the capacity credit of a wind plant. The LOLE is normally expressed in terms of days per year and indicates the expected number of days in a year in which the projected load exceeds the available generation capacity. Of course the goal of the utility is to keep this probability small making an appropriate trade-off between cost-minimization and reliability. However, it does not take account of the severity of the generation deficiency, nor does it give any information on the frequency or duration of the deficiency.
- **The loss of energy expectation** (LOEE) is a more appealing index because it gives the expected energy that will not be served by the available generation capacity and thus indicates the severity of the generation deficiency.
- **The F&D criterion** is an extension of the LOLE index that also gives information on how often the expected generation deficiency will occur and how long it will last. The criterion is a combination of the Sustained Average Interruption Frequency Index and the Sustained Average Interruption Duration Index. The F&D index is not as widely used in generation planning as the LOLE index.

Despite the advantages of the probabilistic reliability indices, the deterministic reserve margin is still widely used in the utility industry for generation planning.

When adding different generation technologies to the grid, such as a wind farm, these expansion options are assessed in terms of their capacity and energy values. The energy value is usually the cost of providing the energy with an alternative expansion plan. The capacity value is the value of improved reliability (expressed in LOLE) that the resource expansion plan provides to the system. The calculation of the capacity value is based on the effective load carrying capability (ELCC) of the particular resource expansion option.[7] The ELCC of a resource can be determined by calculating the LOLE with and without the resource.

Another approach can be used for the last step of the calculation. Instead of increasing the load to bring the LOLE down to the original value, perfectly reliable capacity can be added to the original system (without a new resource) until the reliability measurement reaches the same value as with the new resource. This results in a "firm capacity equivalent" for the resource. For example, if adding additional wind power plants results in lowered reliability, we add firm capacity, in the form of a representative gas plant, to compensate for the reliability loss. The addition of wind and the necessary backup will result in an equally reliable system. Depending on how load increases and firm capacity additions are treated in the models, the ELCC and firm capacity equivalent can have the same or slightly different values. Many researchers and utility planners use the term "capacity credit" for both ELCC and firm capacity equivalent.

2.2 Valuing Wind Energy Contributions

The capacity value of intermittent renewable technologies is often overlooked. Some utilities contend that, because PV and wind generation output depend on uncontrolled resources and cannot be used to meet the system demand on command, no capacity value or credit can be given unless there is adequate energy storage. This argument implies that if intermittent renewable generation options are adopted, utilities have to make available other "firm capacities" to back up the intermittent renewables in order to maintain the same reliability. However, reliability analyses have shown that intermittent renewable generation does contribute to the system reliability and can be used to reduce the capacity requirement of the utility system (Flaim and Hock, 1983; Wan and Parsons, 1993). Unlike conventional generators, however, the capacity value of intermittent renewable energy strongly depends on the correlation between the utility load and the pattern of wind resource availability.

Several factors play an important role in establishing the capacity credit of wind energy systems. The timing of wind plant output relative to the utility demand profile is critical. If wind plant output does not coincide with utility peak loads, the wind energy system will have a low capacity credit. A second factor influencing capacity credit is penetration level. As seen later in this section, there is a noticeable saturation effect in capacity credit as the penetration level of wind power increases.

Smith and Ilyin (1990) have performed ELCC computations on installed wind power in California for PG&E. An experimental 2.5 MW MOD-2 unit (now discontinued) located at Solano County, California, achieved an ELCC of 74% of its rated capacity in 1987. The ELCC of wind turbines installed at Altamont Pass, California, showed large year-to-year variations, reaching 22% of the total

[7] Garver (1966) defined the ELCC of a resource as the amount of constant load increase the system could carry while maintaining the original system LOLE.

installed capacity (name plate rating) in 1987 but only 14% in 1988.[8] The seasonal wind patterns at both the Solano County MOD-2 site and Altamont Pass are highly regular, and the available wind energy at both sites correlates well with PG&E's seasonal load (i.e. winds at both sites are much stronger in the summer when the demand on the PG&E system is higher). Moreover, the daily wind pattern at Solano County tends to peak, producing maximum power, during the PG&E peak load hours (3:00 - 4:00 p.m. PDT). The daily wind pattern at Altamont Pass tends to produce a maximum output after PG&E's peak load hours. Differences in wind patterns at Solano County and Altamont Pass cause the variations in wind power capacity value. These results indicate clearly that the capacity value of intermittent renewable energy resources depends on the utility system load pattern and is site specific.

The results to date also confirms one of the major concerns often expressed about wind power: that a wind plant would need to be backed up with an equal amount of dispatchable generation (Parsons and Milligan, 2004). It is now clear that, even at moderate wind penetrations, the need for additional generation to compensate for wind variations is substantially less than one-for-one and is generally small relative to the size of the wind plant.[9]

The results presented here must be considered in the context of a centrally planned electricity system. In that system, the system operator produces a schedule representing the preferred mix of generation to meet demand; included in the schedule are the quantity of output (generators) and consumption (loads), details about any adjustment bids, and the location of each generator and load. The schedule details the quantities and location of trades among scheduling coordinators and is balanced with respect to generation, transmission losses, load and trades. When deciding to integrate intermittent sources, the generator can dispatch certain plants and increase reserves in order to optimize operation over the entire system.

All of this has the potential to change with electricity deregulation. Since the beginning of 1998, many states in the US have considered and implemented partial electric industry restructuring. This move towards more competitive electricity markets has several potential impacts:

---

[8] If the ELCC is calculated against the actual maximum output of wind farms during the year instead of total installed capacity to account for any non-operational and overrated wind turbines, the ELCC value at Altamont wind farms would increase to about 40% in 1987 and 20% in 1988. Using the same formula, the ELCC value at Solano County would increase to 80% in 1987.

[9] Halberg (1990) reported that capacity credit of a wind energy system at low penetration would be approximately equal to the installed wind power capacity multiplied by its average yearly capacity factor. At higher penetration, the wind power capacity credit will reach an asymptotic value, which is a function of wind energy availability and existing system generation mix. In the case of the Dutch electric system, the capacity credit starts from 26% at a low penetration level to 7% at a high penetration level (31% of the installed capacity). Coelingh et al. (1989) found that for 1,000 MW of wind power (representing 9% of the total system load) in the Netherlands system, the calculated capacity credit would be 184 MW. Their calculations also showed the saturation effect of capacity credit.

- With deregulation come competitive retail markets that allow for bidding of energy in the day-ahead and real-time markets. The capacity credit given to intermittent sources such as wind will be critical in determining how competitive they become.
- However, these competitive retail markets also bring with them an opportunity for consumers to demand and receive "green electricity." Many utilities around the country now allow customers to voluntarily choose to pay more for electricity generated by renewable sources.

2.3 Capacity Credit and Wind Penetration

Several early studies examined the ELCC of wind power systems in an actual utility environment. Flaim and Hock (1983) summarize the results in Figure 2. Two important observations can be made from the figure. First, the effective load carrying capability of the wind farms varies widely among different utilities, ranging from 5% to almost 50%. Second, as the wind energy system penetration increases, the ELCC drops quickly to a constant level. This means that the incremental ELCC value from each successive addition of wind power generation becomes smaller and smaller and approaches zero at a sufficiently high penetration level. Because each wind generator produces only during certain hours, more wind generators will produce more power during those hours and minimize the effect of generator outage. The net system loads during those hours will become less, and the LOLE during those hours will diminish. However, even as the number of wind generators continues to increase, new peak loads emerge at other times when the wind speed is low or there is no wind at all. These new peak loads determine the capacity requirement of the system regardless of wind penetration. Dispersing wind turbines over a wide area will reduce the rate of decrease of the ELCC but will not completely eliminate the phenomenon.

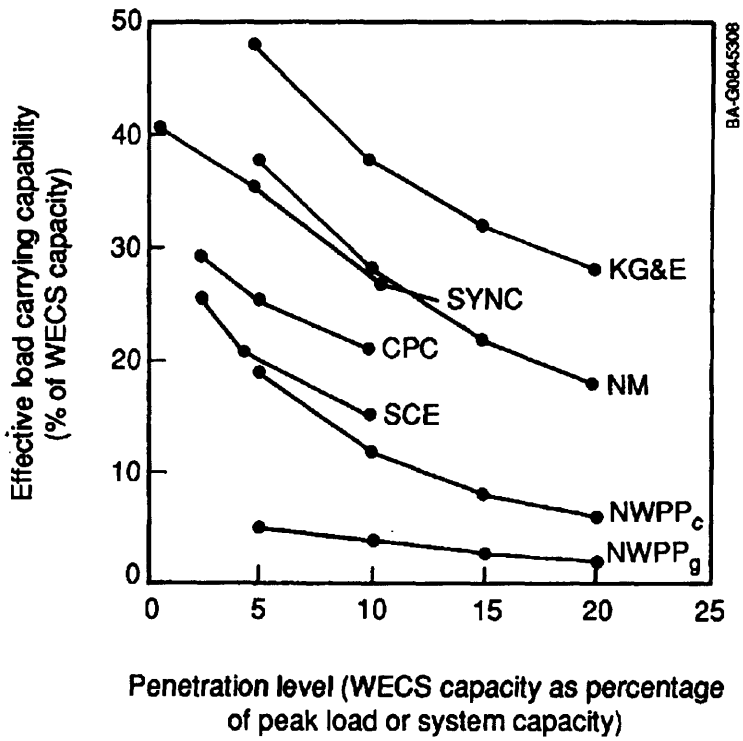


Figure 2 - Effective load carrying capacity of wind energy conversion systems (WECS)

Additional research by the U.S. National Renewable Energy Lab (Parsons and Milligan, 2004; Smith and DeMeo, 2004) has addressed the question of integration impacts at varying levels of wind penetration. They concluded the following:

- First and most important, the incremental cost of ancillary services attributable to wind power is low at low wind penetration levels; as the wind penetration level increases, so does the cost of ancillary services (Smith and DeMeo, 2004).
- Second, the cost of ancillary services is driven by the uncertainty and variability in the wind plant output, with the greatest uncertainty in the unit-commitment time frame, or day-ahead market (Smith and DeMeo, 2004). Improving the accuracy of the wind forecast will result in lower cost of ancillary services.
- Third, at high penetration levels the cost of required reserves is significantly less when the combined variations in load and wind plant output are considered, as opposed to considering the variations in wind plant output alone (Parsons and Milligan, 2004).

Perhaps the most significant long-term problem for intermittent renewable generation is the noticeable saturation effect in capacity credit as the penetration level increases. The output of conventional generators generally is independent of location. As more and more conventional units are added to the system, the load carrying capacity of additional units as the same as the previous units. In contrast, the output and value of intermittent renewable generation technologies depends on the density of natural energy flow and is site specific.

When the amount of renewable energy generation connected to a system is only a small fraction of the total system capacity, the impact on the system load-following and reserve margin requirements will be minimal. The demand for electricity is stochastic in nature, and the system controller sees the output intermittency of the renewable energy generation as merely an extension of natural load fluctuations. The output intermittency of renewable energy generation and the utility's intrinsic load variations are generally independent of each other; their combined effect on the system control is random load fluctuations, perhaps with somewhat wider variance.

Intermittent renewable energy technologies derive most of their value from displacing generation from conventional units that use higher-cost fuels. With an increased penetration level, more and more conventional generating units may be needed on line and partially loaded to add load-following capability and operating reserve to the system. The increased cycling duties and decreased efficiency caused by the partial loading of these generators will increase fuel consumption and maintenance costs. At certain penetration levels the savings offered by intermittent generations could be offset by the above operations, making it uneconomical to add intermittent generations into utility systems.[10]

2.4 The Role of Storage

Storage may increase the value of intermittent generation. However, studies generally show that dedicated storage systems for renewables are currently not viable options for utilities because of the high capital costs of storage technologies (Denholdm and Kulcinski, 2003; DeCarolis and Keith, 2002; Schienbein, 1997). As the technology matures, the cost of these storage systems will change over time and we should keep them in mind.[11]

Electric utilities have considered using energy storage systems as a load-leveling device. Pumped-storage hydro has long been established as the primary type of energy storage plant for electric utilities, and its operations and economics are well understood. The technical feasibility of battery storage

[10] Case Study: Eltra Danish electric utility company, has the world's highest wind power penetration rate at 60 percent. Yet the systems' grid managers consistently maintain reliability through contracted thermal plant spinning reserves as well as extensive transmission interties with adjacent systems. These interties are vital load-balancing tool for Eltra, with a total capacity of over 65 percent of the system's pea load. Although Eltra has reported significant load-balancing impacts from the high proportion of wind power on its system, the utility has not determined the amount of operating reserves specifically lined to providing backup wind power generation. Eltra is well aware of its potential vulnerability during periods of light demand and is careful to contract for sufficient operating reserves and monitor intertie capacity.

[11] A report produced by the Iowa Department of Natural resources is a great source of information about storage systems (2001). It discusses wind hybrid technology options that mix wind with other power sources and storage devices to help solve the problem of intermittency. It also presents the average cost and cost-benefit of each application along with references to manufacturers.

systems for electric utilities has been demonstrated (EPRI, 1986). Compressed air and other types of energy storage systems are also being investigated for electric utility applications.

The combination of intermittent energy technologies and energy storage systems has the potential of reducing output fluctuations. A properly sized energy storage system can supplement intermittent energy resources by providing firm capacities during periods of cloudy or calm weather. However, this combination also increases the cost of intermittent renewable energy resources to electric utilities. In addition to system load leveling, energy storage systems reduce operating costs and improve the operating flexibility of electric power systems because they are capable of providing non-spinning reserve for the utility system. Storage can add flexibility and value to utility operations, but it should generally be a system-wide consideration based on the merit of the storage system.

In the section below I outline some of the recent studies done on the feasibility of different options for energy storage.

2.4.1 Pumped hydro storage

Pumped hydro is capable of storing large amounts of energy. Usually this technique, which is based on moving water from a reservoir at low elevation to a reservoir at higher elevation, is employed in electric utility-scale applications. When power is required, the water runs though a hydroturbine to generate electricity. Pumped hydro, where applicable, is cost-effective, but it is usually limited to existing hydro plants, which are geologically selective. An important limiting factor to the use of pumped hydro is degradation of natural habitat. Schienbein (1997) adds that when pumped hydro is coupled with wind turbines the number of practical sites is greatly reduced. Therefore, this type of energy storage is typically limited to electric utility operations, and then only under special circumstances.

Using existing hydropower facilities as energy storage systems for renewable energy technologies is a promising concept, but more research is needed to determine the effect on existing hydropower operations and to assess the environmental impact of potentially increased fluctuations of downstream flow (Wan & Parsons 1993).

2.4.2 Compressed air energy storage

Compressed air energy storage (CAES) systems are based on conventional gas turbine technology. The principle of CAES is the utilization of the elastic potential energy of compressed air. Energy is stored by compressing air in an airtight underground storage cavern. To extract the storage energy, compressed air is drawn from the storage Bessel, heated and then expanded through a high-pressure turbine, which captures some of the energy in the compressed air. The air is then mixed with fuel and combusted, with the exhaust expanded through a low-pressure gas turbine.

2.4.3 Advanced battery energy storage (BES)

Flow batteries are a hybrid between electrochemical batteries and fuel cells. They use pumps to circulate a pair of electrolytes past an ion-exchange membrane similar to the ones employed in many fuel cells. Ions pass across the membrane from one electrolyte to the other to charge and discharge the battery.

Life cycle costs and greenhouse gas emission contributions are detailed in Denhold and Kulcinski, 2003. GHG emissions from pumped hydro when coupled with renewable energy systems are lower than those from BES or CAES.

Alternative energy storage technologies, such as flywheels, capacitors, hydrogen and magnetic fields are not yet suitable for utility scale electricity storage due to their high cost and/or low round trip conversion efficiencies (Denholdm and Kulcinski, 2003).

2.5 Approach of Other Models

In this section I describe how several other energy models represent wind resources, cost of power generation and intermittency in wind power generation. A summary of the models and their treatment of wind energy is provided in Figure 3. This discussion sets the context for the modeling and analysis work done on the MIT EPPA model.

2.5.1 MARKAL – International Energy Agency (IEA)

The Market Allocation (MARKAL) model is a partial equilibrium bottom-up energy system technology optimization model employing perfect foresight and solved using linear programming with numerous model variants that expand the core model to allow for demand response to price and elastic demand, uncertainty, and endogenous technology learning

Under this model energy demand is exogenous and renewable energies are characterized by investment and operating costs. For renewables such as wind and solar, the specific season/day-night capacity factors describing the operational characteristics of the technologies are provided and do not change over time. For targeted technologies of interest, endogenous technology learning can be employed to examine the drop in investment cost of the technologies as their deployment increases (Smekens, 2004).

2.5.2 MiniCAM 2001 – Pacific Northwest National Laboratory (PNNL)

The Mini-Climate Assessment Model (MiniCAM) is developed by the Joint Global Change Research Institute (Edmonds *et al.*, 1997; Brenkert *et al.*, 2003). It is a partial-equilibrium model (energy and land-use) including numerous energy supply technologies, agriculture and land-use model, and a reduced-form climate model. Emissions include CO_2, CH_4, N_2O, and SO_2. The US EPA is one the major users of the MiniCAM and has employed it to analyze various policies to address climate change. The MiniCAM has been widely used in international energy modeling, in venues such as the Intergovernmental Panel on Climate Change (IPCC) and the Stanford Energy Modeling Forum (EMF).

The model includes solar PV, wind, hydroelectric (including geothermal), biomass (two separate supply streams: traditional/ waste biomass and grown biomass from dedicated farms), storage technologies for solar and wind, and space-satellite solar. Wind and solar costs are input as exogenous parameters by time period and by region. Intermittence of solar and wind is represented by placing limits on maximum penetration within any region's end-use electricity market. Hydroelectric is resource constrained by region. Biomass from dedicated farms is derived from the model's Agriculture and Land Use module, in which biomass crops compete for acreage with food crops.

2.5.3 NEMS - Energy Information Agency (EIA)

The National Energy Modeling System (NEMS) model is a product of the U.S. Department of Energy, Energy Information Administration, Office of Integrated Analysis and Forecasting (EIA, 2004). It is a general equilibrium energy-economic model of U.S. energy markets with energy-related emissions. The emissions modeling includes energy system-wide carbon dioxide and methane emissions, with the capability to include carbon dioxide fees or caps, and emissions caps, trading, and banking of emission credits for carbon dioxide, sulfur dioxide, nitrogen oxides, and mercury in the electricity generation sector. NEMS is used annually to produce the *Annual Energy Outlook* and other analyses with projections 20 to 25 years into the future, and model results calculated on an annual basis over that time period.

NEMS characterizes renewables for central station electricity supply -biomass, conventional hydroelectricity, geothermal, landfill gas, solar PV, solar thermal, and wind. Resources are characterized for each technology, by NEMS region and, for intermittent technologies, by time of day and season. All fossil, nuclear, and renewable technologies incur uniform interconnection charges within region; wind incurs small additional interconnection charges varying by distance to the existing lines. NEMS accommodates limited interregional electricity trade and trade with Canada.

Intermittent penetration is limited within region and by reducing capacity contributions to reserve margin. Currently, there is a fixed limit on intermittent's share of regional generation (10-15% of regional generation). Large capital cost reductions happen over time but performance is fixed. As of 2005 there is a move to replace fixed capacity credit with variable capacity credit, which is a function of intermittent penetration. This approach allows higher penetration of intermittent capacity, but requires increasing investment in "back-up" capacity.

2.5.4 WinDS – National Renewable Energy Laboratory (NREL)

The Wind Deployment Systems (WinDS) model is a multi-regional, multi-time-period model of capacity expansion in the electric sector of the U.S. It is developed and maintained by the National Renewable Energy Laboratory and is designed to estimate market potential of wind energy in the U.S. for the next 20 – 50 years under different technology development and policy scenarios. It utilizes a linear program optimization (cost minimization) for each of 25 two-year periods from 2000 to 2050 and solves over sixteen time slices in each year: four daily and four seasons. There are four levels of regions (wind supply/demand, power control areas, NERC areas, and interconnection areas) and four wind classes (3-6).

WindDS proceeds one period at a time minimizing total system costs (the sum of capital, operating, fuel, transmission, ancillary services, interruptible load costs, and wind forecasting error penalties). The solution is also subject to constraints on: wind resources, transmission, ancillary services, load and peak requirements, and conventional technologies' performance and availability.

Model	Determination of Market Penetration	Wind Resources	Cost of Power Generation	Treatment of Intermittency
WinDS	Linear program optimization (cost minimization) for each of 25 two-year periods from 2000 to 2050. Sixteen time slices in each year: 4 daily and 4 seasons	Many wind supply and demand regions using latest NREL Wind Atlas	Capital costs, operating costs, and capacity factors can vary by wind class and over time according to user inputs	Explicit accounting for regulation and operating reserves, wind oversupply, and for wind capacity value as a function of the amount and dispersion of wind installations
MARKAL	Linear programming determines least-system-cost and allocates generation across technologies accordingly	DOE/EPRI Topical Report 109496: "Renewable Energy Technology Characterizations," updated, provides potential and technical characteristics	Capital cost –$983/kW, today –Exogenous specification of cost reduction Some variation by wind class Capacity factors improve over time	Dispatch –Output added to total production –3 season, 2 time-of-day wind output segments –Varies by wind class
NEMS	LP determines least-system-cost for each region Explicitly models feedback among demand and competing power sources, including conservation	Uses PNL Wind Atlas, with "moderate" land use restrictions (1992) Each region includes 3 season, 3 time-of-day representation of wind output variation	Capital cost is $1000/kW, today and uses experience curve approach to cost reduction Varies based on regional factors, but not a function of wind class	Intermittency limit: 20% of regional generation –Prevents surplus generation during low-load period Capacity credit for initial penetration, set at peak-load capacity factor –Marginal capacity credit "decays" as fraction of generation increases
MiniCAM	Least-cost supply for electricity (and hydrogen) for each region determined based on a logit sharing approach Electricity demand is self-consistently calculated in each time step (as a function of income, costs, etc.) along with demand for other end-use energy service delivery options	Wind resources not currently represented	Cost represented as exogenously specified cost per kw-hr. Cost is assumed to decline with time due to technological progress.	Wind limited to specified fraction of total end-use electricity demand.

Figure 3 - Summary of Energy Models (US EPA, Renewable Energy Modeling Series, 2003)

CHAPTER 3: Modeling Intermittent Sources in a General Equilibrium Context

3 Why General Equilibrium Models

In most of the models, the cost of power generation is exogenously determined, and trade between regions and substitutions between sectors are not considered. In order to fully analyze the forces driving GHG emissions we need to consider not only energy supply and its emissions but also factors influencing demand and the origins of a number of other climate-relevant emissions. Computable general equilibrium (CGE) models allow us to consider multiple interacting agents and multiple production sectors. As a result CGE models can have a high level of detail and can reproduce important features of the economy.

The MIT Joint Program on the Science and Policy of Global Change has developed a CGE model that analyzes the processes that produce greenhouse-relevant emissions and assesses the consequences of policy proposals intended to control these emissions (Babiker *et al.*, 2001; Reilly *et al.*, 2003, McFarland *et al.*, 2004). The model includes several non-extant energy technology options: including shale oil, natural gas combined cycle, wind, solar and biomass. Currently, all produce perfect substitutes for oil, gas or electricity as appropriate, except for the intermittent sources, wind and solar power. Because of the nature of their formulation, the amount of intermittent energy tends to be share preserving and will not allow large-scale expansion of wind without recalibration over time. The research below presents a new accounting framework that will improve the representation of intermittent energy in CGE-type models.

3.1 The Structure of the MIT EPPA Model

The MIT Emissions Prediction and Policy Analysis (EPPA) model is a multi-region, multi-sector, recursive-dynamic multi-regional computable general equilibrium (CGE) simulation of economic growth, energy use and greenhouse gas (GHG) emissions over the next 100 years. CGE models use data on the input-output structure of the economy and estimated trends in the supplies of key economic inputs (e.g. labor and energy resources) to simultaneously compute the prices and flow quantities of goods and services in the economy in the future. Because the simulation computes prices, quantities and income, it is a useful tool for understanding the effects of GHG emissions constraints on different markets and different economies.

Version 4 of the model used for this analysis has been updated in a number of ways from Version 3 documented by Babiker *et al.* (2001). It includes non-CO2 GHGs, greater disaggregation of technologies in the electric sector, and updated evaluation of economic growth and resource availability (Hyman *et al.*, 2003; McFarland *et al.*, 2004; Reilly *et al.*, 2003). Its Social Accounting Matrix (SAM) is built on the Global Trade and Analysis Project (GTAP) data set, which accommodates a consistent representation of energy markets in physical units as well as detailed accounts of regional production and bilateral trade flows (Hertel, 1997). This new version of the model has been updated to GTAP5-E, with a base year of 1997. From 2000 onward, EPPA is solved recursively at 5-year intervals.

Within EPPA, the world is divided into 16 regional economies, linked by trade. The regional structure of the model is shown in Figure 4. The Annex B Parties are aggregated into seven nations or multi-nation groups.[12] There are nine Non-Annex B regions with China, India, Indonesia, and Mexico individually identified.

Annex B	Non-Annex B
USA	China
Japan	India
Europe[a]	Mexico
Canada	Indonesia
Australia & New Zealand	Persian Gulf
Russia[b]	Africa
Eastern Europe[c]	Latin America
	East Asia[d]
	Rest of World[e]

[a] The European Union (EU-15) plus countries of the European Free Trade Area (Norway, Switzerland, Iceland).

[b] Russia and Ukraine, Latvia, Lithuania and Estonia (which are included in Annex B) and Azerbaijan, Armenia, Belarus, Georgia, Kyrgyzstan, Kazakhstan, Moldova, Tajikistan, Turkmenistan, and Uzbekistan (which are not). The total carbon-equivalent emissions of these excluded regions were about 20% of those of the FSU in 1995. At COP-7 Kazakhstan, which makes up 5 to 10% of the FSU total, joined Annex I and indicated its intention to assume an Annex B target.

[c] Bulgaria, Czech Republic, Hungary, Poland, Romania, Slovakia, Slovenia.

[d] South Korea, Malaysia, Philippines, Singapore, Taiwan, Thailand.

[e] All countries not included elsewhere: Turkey, and mostly Asian countries.

Figure 4 - Regional Structure of EPPA 4

The model's simulation horizon is 1997-2100, over which it solves for the quantities of output and inputs in each economic sector in each region, inter-regional trade flows, regional goods prices, and GHG emissions in five-year time-steps. I use an economic model to predict emissions because GHGs are a by-product of economic activity, i.e. the profit-maximizing decisions of firms and the utility-maximizing decisions of consumers in each of these regions. Regional production and consumption activities in EPPA generate GHG emissions, six of which are separately accounted for in the model applying emission coefficients to the levels of activity in the economic sectors of each region.

3.1.1 Aggregate Production Sectors

Figure 5 shows the production structure of the model. In an elaboration of EPPA Version 3 (Babiker et al.,2001), the non-energy goods sectors now identify a services sector and transportation is disaggregated within the household sector. Fossil energy supply sectors are defined as shown, with

[12] Under this aggregation Russia includes a number of regions of the Former Soviet Union (FSU) that are not in Annex B.

resources credited to the appropriate regions. The greatest detail is provided in electric power, with separate aggregate sectors for fossil, hydroelectric and nuclear generation.

Aggregated Production Sectors		Non-Extant Supply Sources
Goods		Shale Oil
Agriculture	AGRI	Unconventional Gas
Energy Intensive Industry	EINT	Wind & Solar
Other Industries	OTHR	Biomass
Services	SERV	Natural Gas-Combined Cycle (NGCC)
Transport	TRAN	NGCC with Capture and Sequestration
Energy		IGCC with Capture and Sequestration
Crude Oil	OIL	
Refined Oil	ROIL	
Coal	COAL	
Natural Gas	GAS	
Electricity	ELEC	
Fossil (oil, gas and coal)		
Nuclear		
Hydroelectric		
Final Demand Sectors		
Household Transport		
Household Other		
Government		
Primary Factors		
Labor		
Capital		
Land (agriculture and biomass)		
Resources (oil, natural gas, coal, shale, nuclear, hydro)		

Figure 5 - Production Structure of the EPPA Model

To illustrate the nesting of production functions applied in the model, Figure 6 shows the structure applied to the Energy Intensive Industry (EINT) and Other Industries (OTHR) sectors. The nesting for other sectors differs depending on their particular characteristics (for details see Babiker *et al.*, 2001). But all of the goods sectors share the features of substitution between energy and value added of primary factors (with elasticity σ_{EVA}), a representation of capital-labor substitution (elasticity σ_{VA}), and substitution between electric and non-electric energy (σ_{ENOE}).

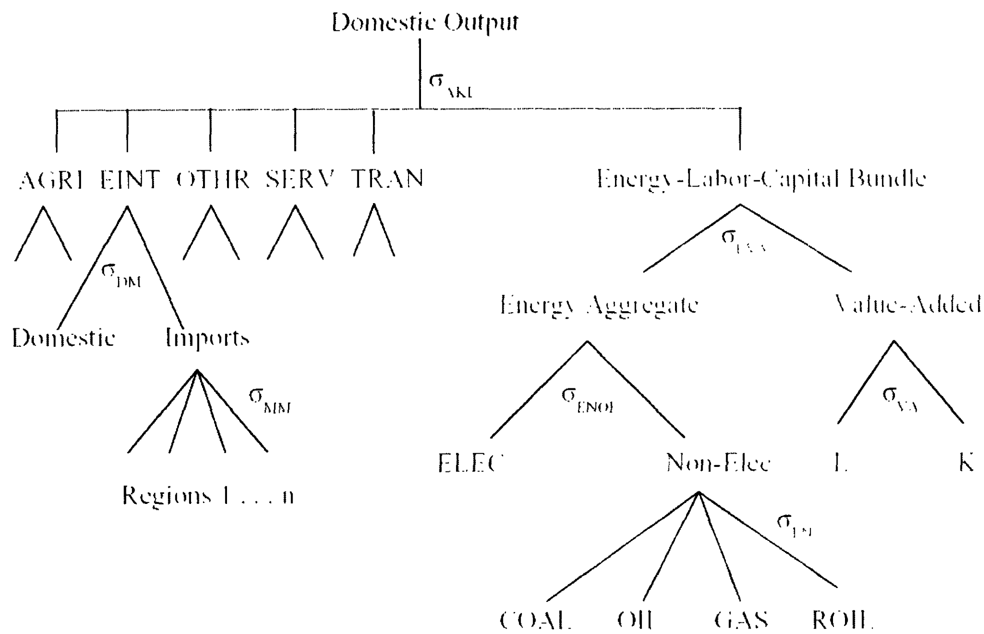


Figure 6 - Production Structure of EINT and OTHR Sectors

In addition to CO_2, EPPA also estimates emissions of the other Kyoto gases (Hyman *et al.*, 2003). The model includes both a prediction of emissions over time, as a function of activity levels in the aggregate sectors, and an endogenous analysis of the costs of reducing them. Also, the model computes emissions of a number of other substances that are important for the atmospheric chemistry of the greenhouse gases and production of aerosols (*e.g.*, NO_X, SO_X, CO, NMVOCs, NH_3, black carbon).

Besides capital and labor, the primary factors of production include land and fossil energy resources (coal, conventional oil, natural gas, and shale). Each of the energy technologies requires input of a specific resource factor, with its interpretation and parameterization depending on the case. For the fossil fuels it is an input to the model of resource extraction, which influences the pattern of exploitation over time. For hydroelectric power it represents the water resource, which grows (or not) over time to represent the expansion of hydro capacity in regions where that is possible. The nuclear resource factor is parameterized to the nuclear fuel input share, and in principle could be related to a uranium resource depletion model as in fossil resources. However, as currently used in the model, nuclear supply is fixed or can decline over time to represent regulatory limits on expansion or possible phase-out.

3.1.2 Modeling Non-extant Supply Options

The non-extant supply sources, listed in Figure 5, are all implemented as production functions, with various outputs modeled as substitutes for energy products from the aggregate sectors. Currently, all produce perfect substitutes for oil, gas or electricity as appropriate, except for the intermittent sources, wind and solar power. All require inputs of labor, capital, intermediate goods, and an appropriate resource factor. The gross output for all of the substitutes is in value terms of the monetary value of the electricity produced by the technology. They differ from one another in detail, but in general the factor proportions are set so as to impose a mark-up above current sources. The magnitude of this premium is determined from current engineering studies. Note that electricity from wind is modeled by a nesting of CES functions, involving inputs of labor, capital, and equipment from the OTHR sector, and a resource factor representing limitations in the wind resource itself. Changes in input prices, and output prices of competing sources, determine when introduction will occur and how large of a share the technology will hold.

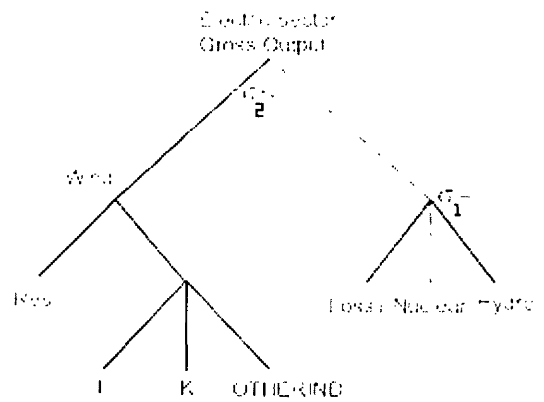


Figure 7 - Wind Power as an Imperfect Substitute

Because of the intermittent nature of wind energy, we are concerned about how to incorporate such a source in a CGE model. Previously, the method in Figure 7 was implemented in the EPPA model. Aggregated-sector electricity from fossil, nuclear and hydroelectric sources are treated as perfect substitutes ($\sigma_1 = \infty$ in Figure 7), as are supplies from NGCC technology without capture and storage, and NGCC and IGCC technologies with capture and storage. Wind supply, however, was modeled as producing an imperfect substitute ($\sigma_2 < \infty$). A CES function controls the substitution at the top of the nest in Figure 7. As a result, this functional form tends to be share preserving and will not allow large-scale expansion of wind without recalibration over time. The relative role of wind power, naturally, is very sensitive to the value chosen for σ_2. Because these features are poorly understood, these quantities tend to function as tuning parameters in model simulations. The research below presents a new accounting framework that will improve the representation of intermittent energy in CGE-type models.

3.2 Modeling Intermittent Energy as Perfect Substitutes

As described above, an intermittent energy source in EPPA was defined as an *imperfect substitute* for conventional power. An alternative formulation is shown in Figure 8. In this method, a kWh of power from a wind source is treated as a perfect substitute for fossil and other sources ($\sigma_2 = 0$), but then a unit of the wind production must include, in fixed proportions, a unit of standby capacity or energy storage (*e.g.*, pumped hydro, or compressed air) so that it is a true substitute as viewed by the system planner or as valued in a deregulated generation market. In this section I will describe in detail the accounting of wind energy as a perfect substitute, which I will refer to below as **"C-INT"** for "compensated intermittent."

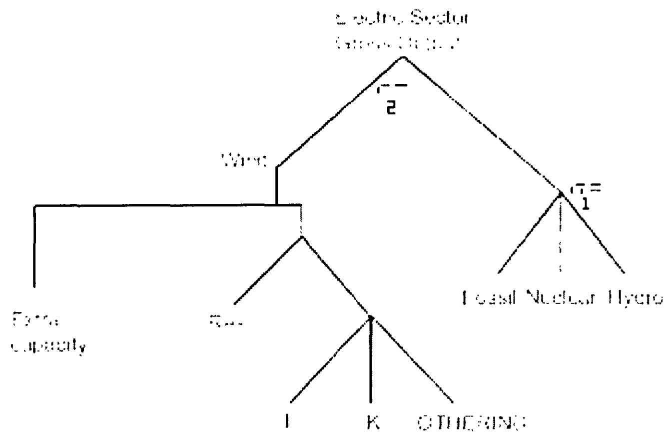


Figure 8 - Wind Power as an Imperfect Substitute (Partial Capacity Credit)

3.2.1 Composition of C-INT

In order to formulate the intermittent source as a perfect substitute for conventional electricity, I pair the electricity from wind energy with additional electricity from a dispatchable source. This structure is shown in Figure 9.

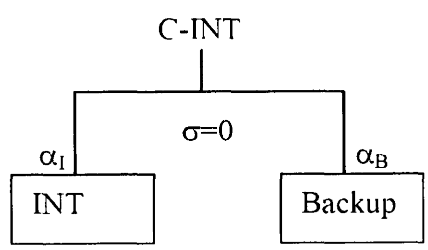


Figure 9 - Composition of C-INT

The total electricity supplied by the "compensated intermittent" source is some combination of kWh from the intermittent source, INT, plus those kWh supplied in a backup source that helps make C-INT a perfect substitute. In this diagram I label the relative cost share of the "INT" source as α_I and the relative cost share of the "Backup" source as α_B where: C-INT = α_I INT + α_B Backup. These cost shares were calculated in three steps.

(1) I calculate the average cost of generating power from wind and the capacity credit for wind energy at a low penetration rate. For this model I used data from an EIA study showing that wind

will receive roughly 75% capacity credit at very low penetration levels, and wind costs 30% more than conventional technologies (EIA, 2003).

(2) I calculate the amount of backup necessary to compensate for the intermittency of the wind source. I then calculate the associated costs of backup needed per unit of wind energy. Given the 75% capacity factor of wind, I assume the backup plant will need to cover 25% of the generation. I also assign the backup plant a unit cost of 1.

(3) Finally, I translate these relative costs into cost shares α_I and α_B. The total cost per unit of C-INT = (cost/unit of wind) * (% wind operation) + (cost/unit of backup) * (% backup operation). To reflect the current cost markup of wind generation, the initial cost/unit of backup is 1 and the initial cost/unit of wind is 1.33. [C-INT = (1.33*0.75)+(1.00*0.25) → C-INT = 0.8 + 0.2] When we multiply the costs by the capacity factors described above we get initial cost shares of: α_I = 0.8 and α_B = 0.2. This means that at initial low levels of wind penetration, the cost of generating "compensated intermittent" energy will be composed of 80% wind costs and 20% backup costs.

3.2.2 Composition of INT and Backup

In this section I describe the inputs to INT, and to the backup. By categorizing the inputs and their cost shares I allow the general equilibrium model to solve for the optimal production from the intermittent source. The overall structure is shown in Figure 10.

The cost of generating electricity from wind is typically broken down into capital costs (the cost of building the power plant and connecting it to the grid), running costs (operation and maintenance) and the cost of financing (how the capital cost is repaid). In our accounting I have translated the costs inputs into three categories:

- *capital* (K),
- *labor* (L), and
- *other intermediate goods* (OTHR).

The inputs to run the Backup are

- *capital for the plant* (K),
- *labor for the plant*(L),
- *capital for transmission and distribution* (KTD),
- *labor for transmission and distribution* (LTD), and
- a fixed amount of *fuel* (F).

In addition, to facilitate the analysis of carbon quotas or carbon taxes, for every unit of fuel used we tie to it a unit of *carbon tax* (C-TAX). In a period when there are no carbon taxes, this value remains zero and has no effect. When there are carbon taxes, it penalizes the "compensated intermittent" based on the amount of fuel consumed in the backup.

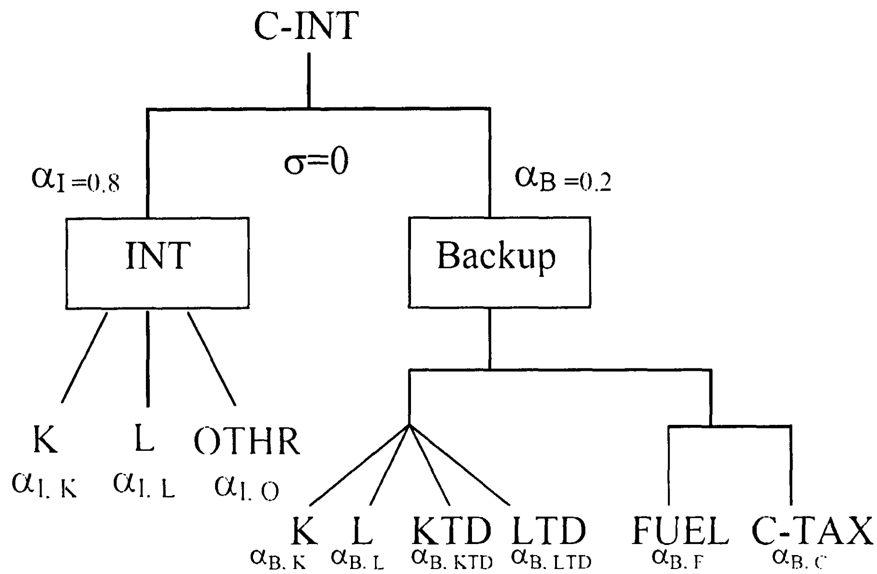


Figure 10 - Cost Inputs to INT and Backup

The factor proportions are given an additional index (ex: $\alpha_{I,K}$). These factor proportions in year 0 are calibrated using current industry costs. We know that on average the capital costs and the intermediate goods account for roughly 85% of the total cost for wind farms (British Wind Energy Association, 1999)[13]. For our accounting this translates into a capital costs share of 60%, intermediate goods share of 25% and labor cost chare of 15% ($\alpha_{I,K} = 0.60$, $\alpha_{I,L}$=0.15, and $\alpha_{I,OTHR}$=0.25). For the backup units I assume we are using state of the art NGCC plants to supply the energy. Previous EPPA modeling research (McFarland *et al.*, 2004) gives us the cost shares for the representative NGCC plant. The exact cost shares vary from region to region. For the USA region the initial values are $\alpha_{B,K}$=0.28, $\alpha_{B,L}$=0.10, $\alpha_{B,KTD}$=0.27, $\alpha_{B,LTD}$=0.09, and $\alpha_{B,F}$=0.26.

As the amount of wind energy changes, these cost shares will also change. For example, as the wind energy industry matures, the capital costs of producing wind turbines will drop, lowering the value of $\alpha_{I,K}$. In the next section I discuss how we account for the changes to the relative cost shares.

3.3 Mark-Ups Affecting Scale Up of Wind in the Model

Because we consider wind as a finite and intermittent source of energy, the amount of capacity credit given to each additional unit of wind in the market will be different. After reviewing the literature, I have concluded that there are three main factors that will affect the cost of wind energy (see Chapter 2 for more details). To account for each of the factors I translated them into separate "Mark-Ups" that will

[13] While the total costs per unit of electricity have gone down in recent years, we have assumed that the relative share of capital costs to labor and operations and maintenance costs have remained the same.

affect each of the cost share inputs (ie: $\alpha_{I,K}, \alpha_{B,K}$) and in turn affect the amount of wind energy in the market. The rationale behind each mark-up as well as their implementation is described below.

3.3.1 Wind Quality and Geographic Diversity of Power Sites

Perhaps the most intuitive effect that one notices when installing wind power is that of **degrading wind resources**. As total wind installation increases, quality wind sites eventually decrease. For a given size of installation, each additional wind farm will provide less and less capacity credit. As a result, we have to increase the size of the installation to ensure that the same quantity of wind power gets produced. This, in turn, translates into an increased cost of production for a unit of electricity from a lower quality wind site. In our model the degrading wind resources effect is accounted for by disaggregating the total wind resources into three categories of wind resources (Classes 5 and 6, Class 4 and Class 3). Wind resource maps estimate the resource in terms of wind power classes, ranging from class 1 (the lowest) to class 7 (the highest). Each class represents a range of mean wind power density (in units of W/m^2) or equivalent mean wind speed at the specified height(s) above ground. Figure 11 (DOE, 1986) illustrates this classification.

Classes of wind power density at 10 m and 50 m[a].

Wind Power Class	10 m (33 ft) Wind Power Density (W/m^2)	10 m (33 ft) Speed[b] m/s (mph)	50 m (164 ft) Wind Power Density (W/m^2)	50 m (164 ft) Speed[b] m/s (mph)
1	0	0	0	0
	100	4.4 (9.8)	200	5.6 (12.5)
2				
	150	5.1 (11.5)	300	6.4 (14.3)
3				
	200	5.6 (12.5)	400	7.0 (15.7)
4				
	250	6.0 (13.4)	500	7.5 (16.8)
5				
	300	6.4 (14.3)	600	8.0 (17.9)
6				
	400	7.0 (15.7)	800	8.8 (19.7)
7	1000	9.4 (21.1)	2000	11.9 (26.6)

Figure 11 - Classes of Wind Power Density

(a) Vertical extrapolation of wind speed based on the 1/7 power law.

(b) Mean wind speed is based on Rayleigh speed distribution of equivalent mean wind power density. Wind speed is for standard sea-level conditions. To maintain the same power density, speed increases 3%/1000 m elevation.

Quantities of wind resources were gathered from World Energy Council (2000) and redistributed into the 12 EPPA regions.[14] Since wind power classes are defined by power density we can utilize the current industry costs (based the most ideal wind sites) to project expected costs for lower quality sites. In the model generating one unit of electricity from a Class 4 site will cost 18% more than generating it from a Class 5 site; and generating one unit of electricity from a Class 3 site will cost 36% more than generating it from a Class 5 site. [$\alpha_{14,K} = 1.18*\alpha_{15,K}$, $\alpha_{14,L} = 1.18*\alpha_{15,L}$, $\alpha_{14,O} = 1.18*\alpha_{15,O}$ and $\alpha_{13,K} = 1.36*\alpha_{15,K}$, $\alpha_{13,L} = 1.36*\alpha_{15,L}$, $\alpha_{13,O} = 1.36*\alpha_{15,O}$] Because wind resources of each class are limited, as we run out of good Class 5 and 6 sites, we start to tap into lower class wind sites.

In order to represent the differences in wind resource quality we have shaped the wind productions structure as shown below in Figure 12. In this structure we see that in order to produce wind energy one can utilize a combination of different categories of wind, each requiring a fixed proportion of "resource" and capital, labor and intermediate inputs (F, K, L, and O). The wind classes have an infinite elasticity of substitution, meaning that one is perfectly substitutable for each other. This is because we have already taken into account the additional input requirements to make wind output from each wind class equivalent

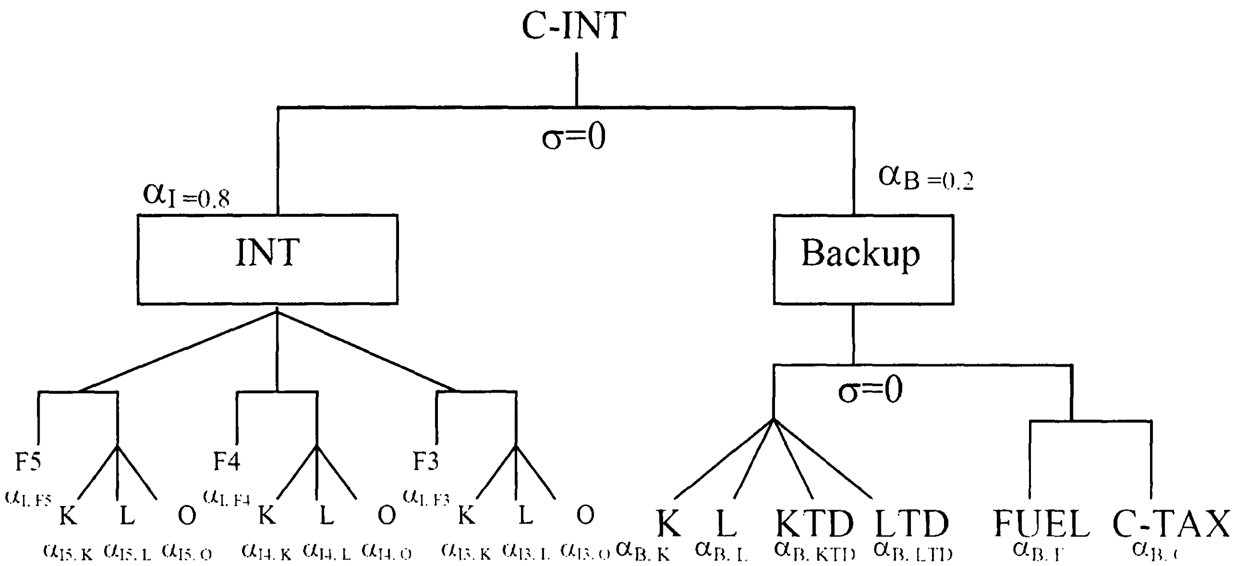


Figure 12 - Wind Class Disaggregation

[14] The use of available wind resource data is an important part of any resource assessment or wind-siting program. However there are limitations to the data. Perhaps the most significant of which is that little of this type of (continued) information has been collected for the purpose of wind energy assessment and many data collection stations were located near or in cities, in relatively flat terrain or areas with low elevation. Thus, this type of data can provide a general description of the wind resource within a large area, but typically does not provide enough information for the detailed identification of candidate sites for wind development.

In reviewing the literature regarding wind resources we have found another phenomenon we should consider. As wind grows, dispersing wind turbines over a wider area will change the rate of decrease of the effective load carrying capability (ELCC). Several studies have examined the issue of geographically dispersed wind sites and the potential smoothing benefit on aggregate wind power output (Kahn *et al*, 2000; Ernst *et al.*, 2002). The principle behind this benefit is that lulls in the wind tend to be more pronounced locally than over a wide geographic area. Building wind capacity at different locations may help reduce the problems caused by the intermittency of the wind resource. All of these analysts found that the geographic spread of wind generators provides a smoothing benefit when wind output is aggregated.

For the purposes of this model, we assume that a centralized systems operator makes the wind installations. As a result, installations are sited in order to maximize the capacity credit of the new plants. This way the benefits of geographic dispersion are implicitly accounted for in the model.

3.3.2 Penetration Level Mark-ups

As described in Chapter 2, studies have shown that there is a noticeable saturation effect in capacity credit when the penetration level of wind power increases (Flaim & Hock 1983, Wan & Parsons 1993). This means that the ELCC value from each successive addition of wind power generation becomes smaller and smaller and approaches zero at a sufficiently high penetration level. This is because when wind farms increase in size relative to the control area, the *amplitude of power fluctuations* from intermittent wind resources increases, making it difficult for system operators to utilize limited reserve capacity to compensate for periods of low wind power output (Richardson and McNerney, 1993). At higher penetration levels, the wind power capacity credit will reach an asymptotic value, which is a function of wind energy availability and existing system generation mix. Thus, in our model, as penetration level of wind sources rises, the amount and quality of backup also needs to grow.

I account for this increase in backup capacity by applying a multiplier (MU_P) to the backup. This mark-up, MU_P, will affect the all of the cost inputs for the backup ($\alpha_{B,K}$, $\alpha_{B,L}$ $\alpha_{B,KTD}$, $\alpha_{B,LTD}$ and $\alpha_{B,FUEL}$). The multiplier is described by a logistic function shown in Equation 1. Figure 13 shows the relationship graphically. We see that as wind penetration rises the denominator gets smaller resulting in a lower load carrying capacity. This in turn will require more backup capacity to compensate for the loss. For example, at very low levels of wind penetration the ELCC is around 75%. As wind penetration increases to 20%, our ELCC drops to roughly 50%. Now we will require twice as much backup as we did in the low penetration scenario. In order to fully compensate for this loss I multiply the backup costs by 2 (as show in the second graph).

$$MU_P = f\left(\frac{Wind\_Energy}{Total\_Energy}\right) \approx 1 + \frac{4}{1 + \frac{4}{0.17} - 1 * e^{-15*\left(Wind\_Energy / Total\_Energy\right)}}$$

Equation 1 - Wind Penetration Markup

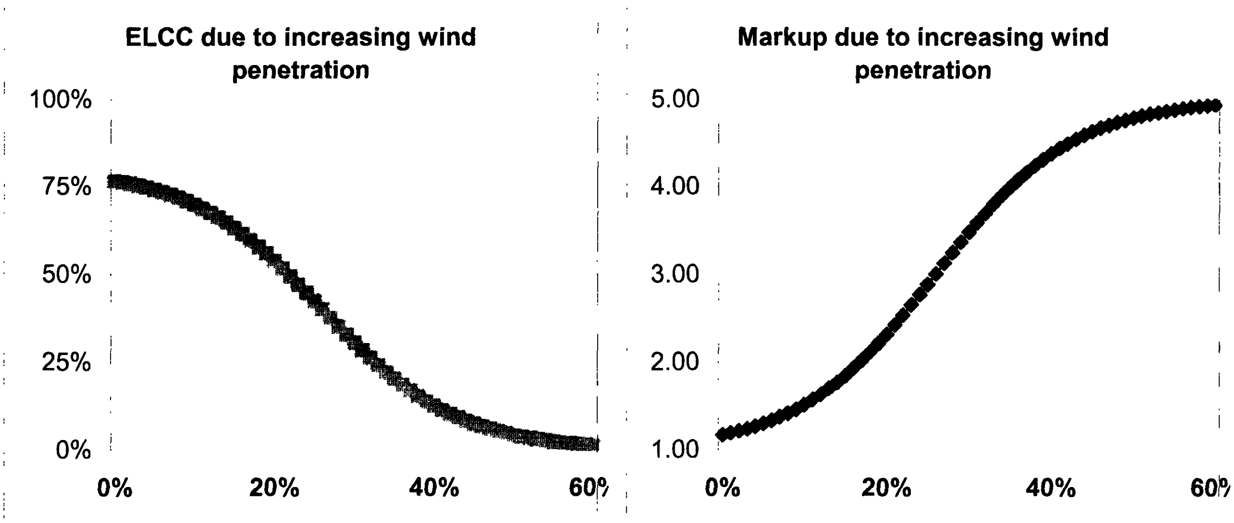


Figure 13 - ELCC and Markup Due to Wind Penetration

3.3.3 Experience and Learning Mark-ups

The third mark-up effect that we have to consider is that of experience. One unknown in capital costs estimates is the potential reduction in costs of system when it is produced on a mass scale. To resolve this problem one can use the concept of learning (or experience) curves to predict the cost of components when they are produced in large quantities. The learning curve concept is based on over 40 years of studies of manufacturing cost reductions in major industries (Johnson, 1985; Cody and Tiedje, 1996, Andersen, 2003). The learning curve gives an empirical relationship between the cost of an object *C(V)* as a function of the cumulative volume, *V*, of the object produced. Functionally, this is expressed as:

$$\frac{C(V)}{C(V_0)} = \left(\frac{V}{V_0}\right)^b$$

Equation 2 – Learning General Equation

Where the exponent *b*, the learning parameter, is negative and $C(V_0)$ and V_0 correspond to the cost and cumulative volume at an arbitrary initial time. From Equation **2**, an increase in the cumulative production by a factor of 2 leads to a reduction in the object's cost by a progress ratio, *s*, where $s = 2^b$. The progress ratio, *s*, when expressed in percent, is a measure of the technological progress that drives the cost reduction. Similar to other industries, as the wind industry matures the cost of producing and maintaining the wind farms will go down. A study done by Andersen (2003) on the Danish wind industry produced an 86% progress ratio. This number reflects experience embodied from both declining equipment costs and improved production. Because this mark-up accounts for all input costs for wind energy, it will be applied to all of the costs inputs for the wind turbine.

The concept of learning (otherwise known as learning by doing or experience curves) is relevant on two scales, regional and global. Within a given industry, more experience on a global scale will help increase efficiencies in production and lower production costs. On a regional scale, the experience may help in lowering permitting costs, and improving infrastructure for the installation and funding of large wind farm projects. In this version of the model I have simplified "learning effects" and implemented the markups as a function of cumulative global wind energy generation. As wind generation grows across the globe and "experience" is gained, costs of building and operating a wind turbine drop, lowering the relative cost shares of WIND-K and WIND-L. This is implemented by summing up the total cumulative generation after each period and calculating the markup using Equation 3. That multiplier is then applied to the cost requirements of the wind turbines, decreasing the cost inputs of wind ($\alpha_{I,K}$, and $\alpha_{I,L}$ in Figure 10) as a function of cumulative generation. A plot of the markup is shown in Figure 14.

$$MU_L = \left(\frac{Cumulative\_Global\_Wind\_Generation}{2} \right)^{-0.217}$$

Equation 3 - Markup Due to Learning

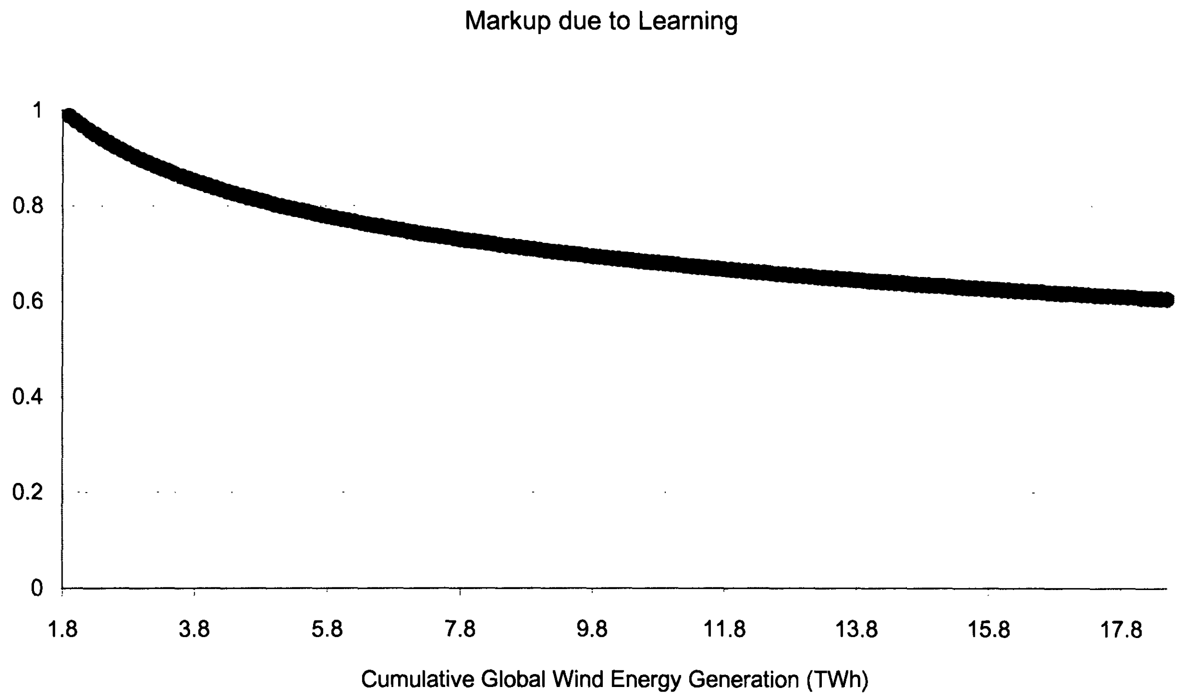


Figure 14 - Markup due to Learning

Together these three markups shift and alter the cost shares of wind energy as penetration levels change. The actual costs of each of the inputs, such as capital and labor, will depend on the rest of the economy. Thus the total cost of wind energy and the resultant wind penetration level will be a function of both the particularities of the wind resource itself and of the rest of the economy. In the next chapter I present the results from the model. The first part shows a "Business as Usual (BAU)" run of the model, a scenario in which no carbon policies or subsidies are applied. The second part evaluates the potential impacts and costs associated with implementing potential policies.

CHAPTER 4: Results from the MIT EPPA Model

4 Introduction – Description of Cases

Using the MIT general equilibrium model described in Chapter 3, I analyzed the global adoption of wind technology under three policy scenarios. They were designed to illustrate the potential of wind energy under different future conditions.

The first scenario is a reference scenario where it is assumed that there are no constraints on greenhouse gas emissions, no carbon policies and no subsidies for renewable generation technologies. I will refer to this as the "Business as Usual" scenario.

The second scenario simulates a stabilization of greenhouse gas (GHG) concentrations at approximately 550 parts per million sometime after the year 2100 when simulated through the MIT Integrated Global System Model. Studies have found that focusing solely on carbon dioxide stabilization missed win-win opportunities and atmospheric stabilization could be more quickly achieved at less cost if multiple gases were controlled (Reilly *et al.*2003). This scenario is implemented in the model through a combination of GHG quotas. SF_6, CH_4, N_2O, HF, and PFC emissions were limited via linear reductions in emissions. Carbon was limited though a carbon tax applied to the economy starting in 2010 through the rest of the century. Detailed description of the EPPA 4 550 GHG stabilization scenario can be found in Joint Program documentation by Franck (2005).

In the third scenario, an initial production tax credit of 1.8-cent per kilowatt-hour is placed on wind energy production in the EUR region beginning in 2000. The tax credit decreases by 0.5-cent per kilowatt-hour in every 5-year period and reaches 0 in 2025. This policy is similar to many of the current tax subsidies in place in different regions of the world. A more detailed description of this type of policy and its initial implementation can be found in Sections 1.3 and 1.4.

The resulting electricity generation paths are presented below followed by detailed analysis of wind generation in each of the three scenarios. I present the results for each of the scenarios for one region, "EUR."[15] The EUR region is discussed here because of its recent growth in wind installations and favorable wind policies. As the wind production structure is the same across all regions, the results for the other regions are similar to the data presented here. The actual wind penetration rates will vary due to different wind resources and labor and capital costs. For each policy scenario I show four figures:

- Total electricity generation by technology
- Total electricity generation share of wind energy
- Detail of wind generation by absolute input cost, and
- Detail of wind generation by relative input cost shares.

[15] The EUR region in EPPA 4 includes the European Union (EU-15) and the countries of the European Free Trade Area (Norway, Switzerland, and Iceland).

4.1 Scenario 1 – Business as Usual

Figure 15 shows the total electricity generation for the EUR region in the Business as Usual scenario. There are eight categories of generation technologies: WIND- our bundle of wind and backup generation, NUCLEAR - traditional nuclear energy, NGCC - natural gas combined cycle plants, NGCC+CAP - natural gas combined cycle plants with carbon capture technologies, IGCC+CAP - integrated gasification of coal combine cycle plants with carbon capture, HYDRO - hydro power, CONVENTIONAL - coal, oil and simple cycle gas technologies, and BIOMASS - energy from biomass sources.

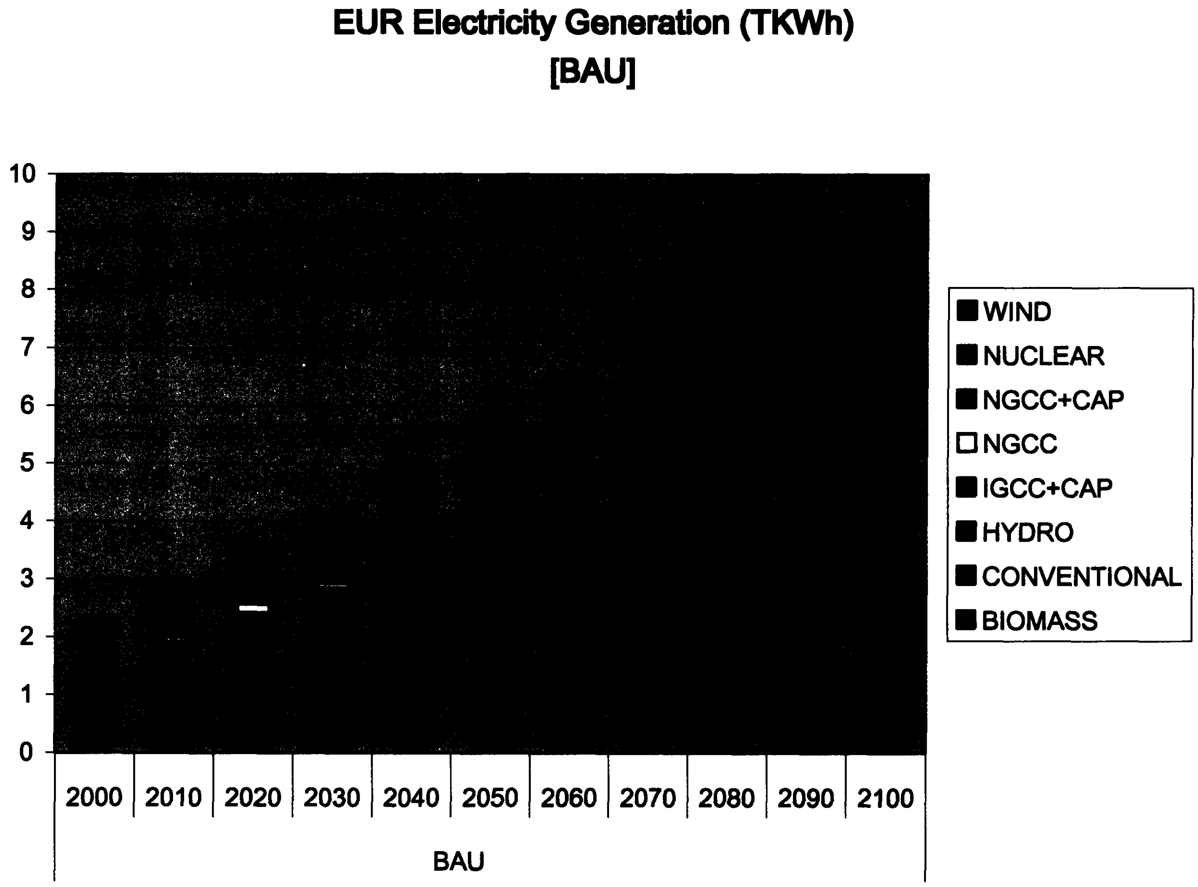


Figure 15 - EUR Electricity Generation - BAU Scenario

We see that with no constraints on greenhouse gas emissions and no carbon policies total electricity generation rises dramatically from 2.37 trillion KWh in 2000 to 9.13 trillion KWh in 2100. During every period fossil-based technologies provide most of the generation capacity. In 2000, CONVENTIONAL technologies contribute 52% of the total generation. By 2100, their contribution rises to 79% of the total generation. Nuclear generation grows at an average of 4.2% per period, rising from

0.77 TKWh in 2000 to 1.10 TKWh in 2100. NGCC produces a small amount of electricity in the years 2010, 2020, and 2030 but phases out quickly. Under this scenario the carbon capture technologies are not economically competitive and do not produce any electricity in any of the years. Wind energy generation also grows by a factor of 15, contributing 0.04 TKWh in 2000 and rising to 0.80 TKWh of electricity by the year 2095. However, wind energy generation drops in the last period, 2100, contributing only 0.14 TKWh of electricity. The dramatic drop in wind generation is partly due to the availability of cheaper conventional energy, but it is not clear that it is the sole cause. Further sensitivity tests would help clarify the factors influencing this phenomenon.

Figure 16 charts the total electricity generation by technology.

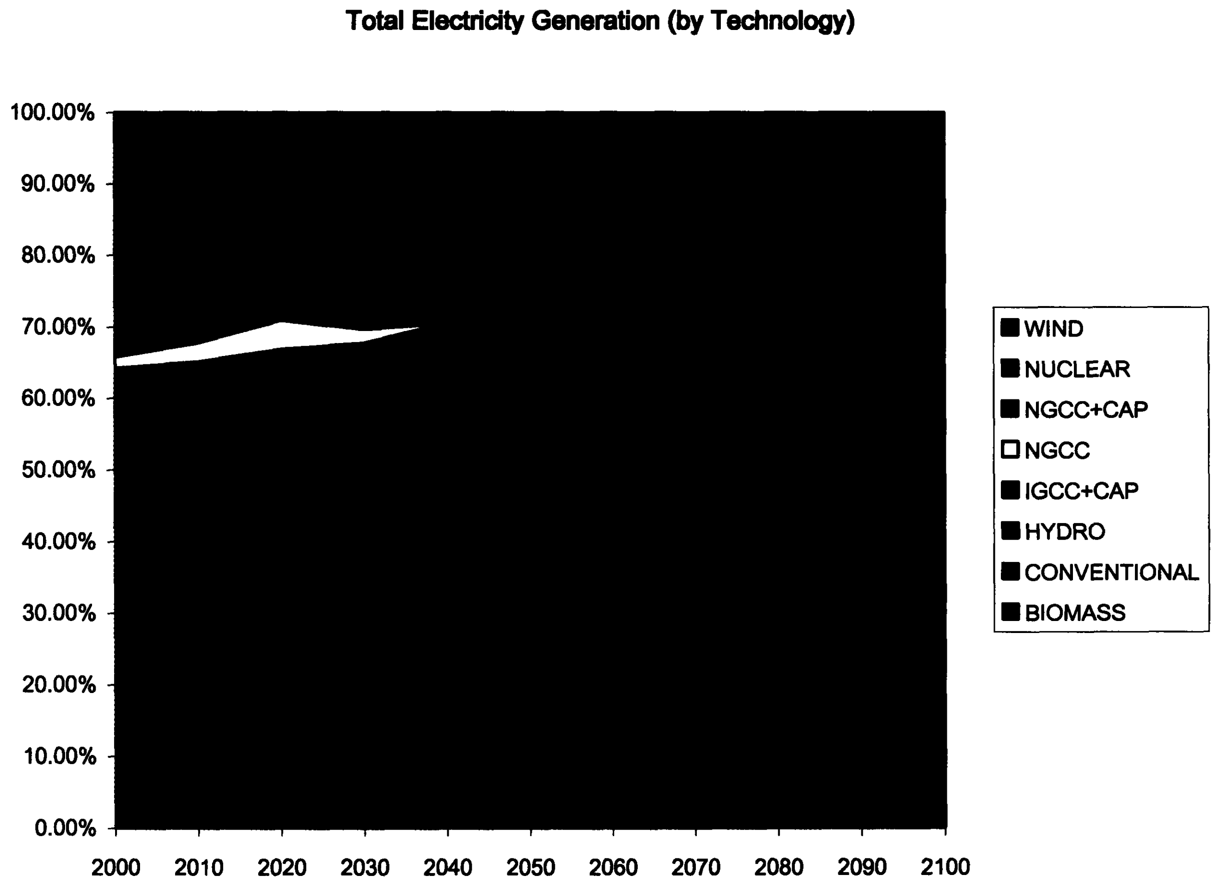


Figure 16 - Total Electricity Generation (By Technology) – BAU Scenario

We see that the share of wind rises steadily from 1.7% in 2000 to 11.8% in 2040, and decreases slowly to 9.2% 2090 and to 1.5% in 2100. Although total electricity output from wind is consistently increasing, after 2030 most of the new demand is being met by conventional technologies, thereby lowering the wind share of total generation. Nuclear and hydropower both grow over time but not nearly as fast as the growth in total electricity generation. As a result the share of nuclear and hydropower declines slightly over time. No other generation technologies achieve significant shares.

In Figure 17 and Figure 18 we show wind energy generation under the BAU scenario in detail. Both graphs show the different input cost shares of the compensated wind technology.

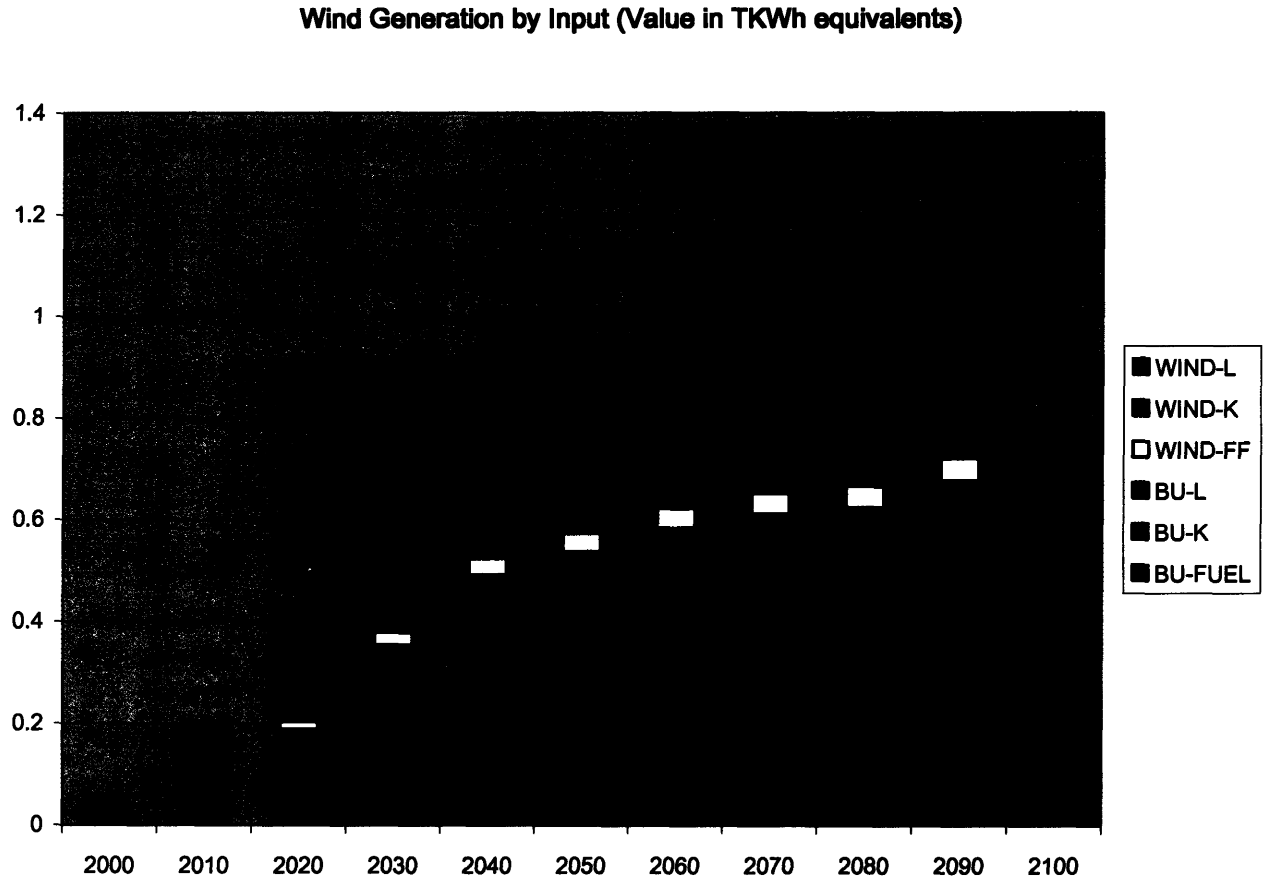


Figure 17 - Wind Generation (by Input Cost Share) – BAU Scenario

The composition of the input cost shares is dependent on three main factors:

- **The impacts due to learning** – As described in Section 3.3.3, the concept of learning (otherwise known as learning by doing or experience curves) is relevant on two scales, national and global. Within a given industry, more experience on a global scale will help increase efficiencies in production and lower production costs. On a national scale, the experience may help in lowering permitting costs, and improve the infrastructure for the installation and funding of large wind farm projects. In this version of the model I have simplified "learning effects" and implemented the markups as a function of cumulative global wind energy generation. As wind generation grows across the globe and "experience" is gained, costs of building and operating a wind turbine drop, lowering the relative cost shares of WIND-K and WIND-L. Refer back to Figure 10 for implementation of the learning curves.

- **The impacts due to increasing wind penetration** – Another effect mentioned in Chapter 3 is that of intermittency in wind power generation. As the wind penetration level increases, the amount of backup power needed to compensate for the intermittent sources increases. In the "Business as Usual" case the wind penetration level increases over time and as a result the backup power also increases. This is implemented by increasing the cost inputs of backup power ($\alpha_{B,K,}$ $\alpha_{B,L,}$ $\alpha_{B,KTD}$ $\alpha_{B,LTD}$ and $\alpha_{B,FUEL}$ in Figure 10, Section 3.3).
- **The relative price of inputs** - In a CGE model, the commodity prices are calculated by solving production and consumption over the entire economy. As a result, the price of labor and the price of capital in a given region are subject to change pending other regional and sectoral activities. In our implementation of the wind production sector we have allowed for some substitution between labor and capital (See section 3.1 and Figure 10). This allows for capital and labor shares to shift as necessary to adjust to the price changes. In the EUR region in the "Business as Usual" case the relative labor costs fall over time and the capital costs rise over time. The ratio of P_K:P_L starts out at 1 and by 2100 becomes roughly 1:2. This means that in a given period one unit of capital input will be more expensive than one unit of labor input. We require both capital and labor as inputs for this system and we allow for substitution to occur between capital and labor. As a result, for a given unit of electricity from wind, capital costs will make up a greater share of the total costs.

Figure 17 gives the detail of the wind energy generation by inputs. It divides the cost of production into six sources, three for the backup units (BU-L, BU-K, and BU-FUEL) and three for the wind turbines (WIND-L, WIND-K, and FF).[16] It shows the total amount of wind energy generation in each period. We can see that as wind energy generation increases over time, contributions from wind inputs and backup inputs also increase. Due to the shift in cost shares described above the backup inputs start to make up a greater percentage of the total cost of generation. In the last period, 2100, when the wind generation is reduced, the individual costs are reduced as well.

[16] BU-L is the sum of the labor costs for the generation plant (B-L) and the labor costs for transmission and distribution (B-LTD). BU-K is the sum of the capital costs for the generation plant (B-K) and the capital costs for transmission and distribution (B-KTD).

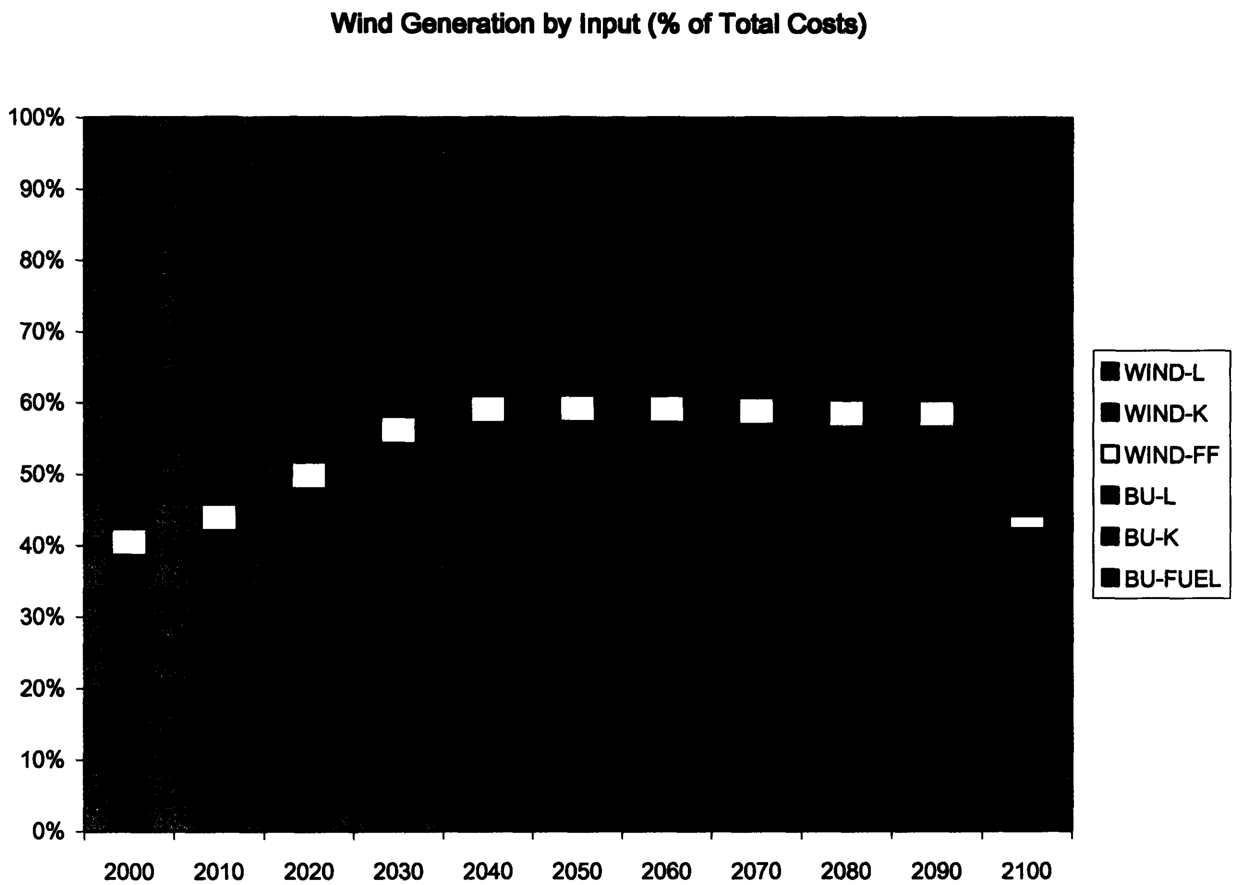


Figure 18 - Wind Generation (by Input %) - BAU Scenario

Figure 18 shows the cost structure for wind for a given unit of wind energy produced. Over time the backup costs become a greater share of the total costs when calculated on a per-unit-generated basis. The backup costs are increasing because additional generation units are needed to cover for the intermittency impacts of greater penetration. The wind related costs, on the other hand, drop due to industry-wide learning. As total generation increases, the amount of cumulative generation also increases. This in turn reduces the cost of the wind turbine inputs. Initially, the wind turbine inputs (WIND-L, WIND-K and FF) account for 61% of the total generation costs; the other 39% are the costs for the backup (BU-L, BU-K, and BU-FUEL). These costs start to level out in 2040 as a result of the penetration rate.

4.2 Scenario 2 – 550 GHG Stabilization

The second scenario presented here is one that puts us on a path to reach a 550 ppm stabilization of greenhouse gas concentrations in 2100. Because of the carbon emission limits and GHG emissions quotas, we expect to see a reduction of total electricity generation and an increase of low carbon emitting technologies. Figure 19 shows the total electricity generation for the EUR region in the stabilization scenario. The generation technologies listed here are the same as in the BAU scenario.

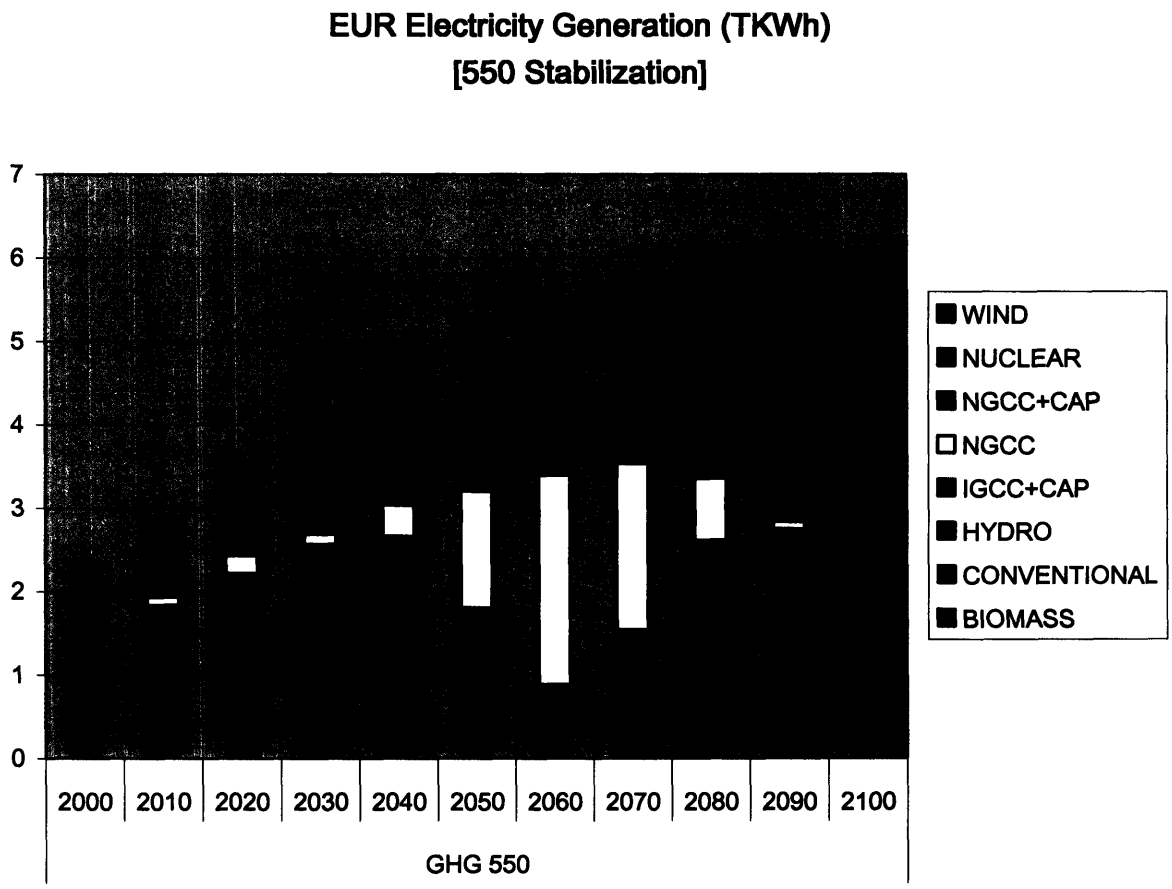


Figure 19 - Electricity Generation - 550 Stabilization

Figure 20 below shows the same data but plots it on the same graph versus the BAU scenario. In this chart we can see a clear differences between the scenarios. Under the 550 PPM stabilization scenario we have tight constraints on greenhouse gas emissions and carbon policies. As a result, the total electricity generation is reduced by 32%. The EUR region generates roughly 6.1 TKWh of electricity in 2100 versus 9.1 TKWh in the BAU scenario. We also see that the use of conventional energy technologies (the ones that produce the most greenhouse gases) becomes severely limited and eventually phased out in 2070. What replaces that technology is first a combination of WIND and NGCC technology. In 2060 wind energy is 19.7% of the total generation and NGCC technology is 45.6% of the total generation; both get phase out by 2090. Eventually in 2070 and 2080 the carbon capture technologies (NGCC+CAP and IGCC+CAP) become cost competitive and produce a significant share of the total generation. We start to get electricity production from IGCC+CAP in 2050. It quickly becomes over 35% of the total generation by 2080. NGCC+CAP starts producing in 2060. Although the technology itself is expensive the strict carbon emissions limits make it cost competitive in the later years. By 2100 it is the dominant electricity generation technology, accounting for over 50% of the total generation.

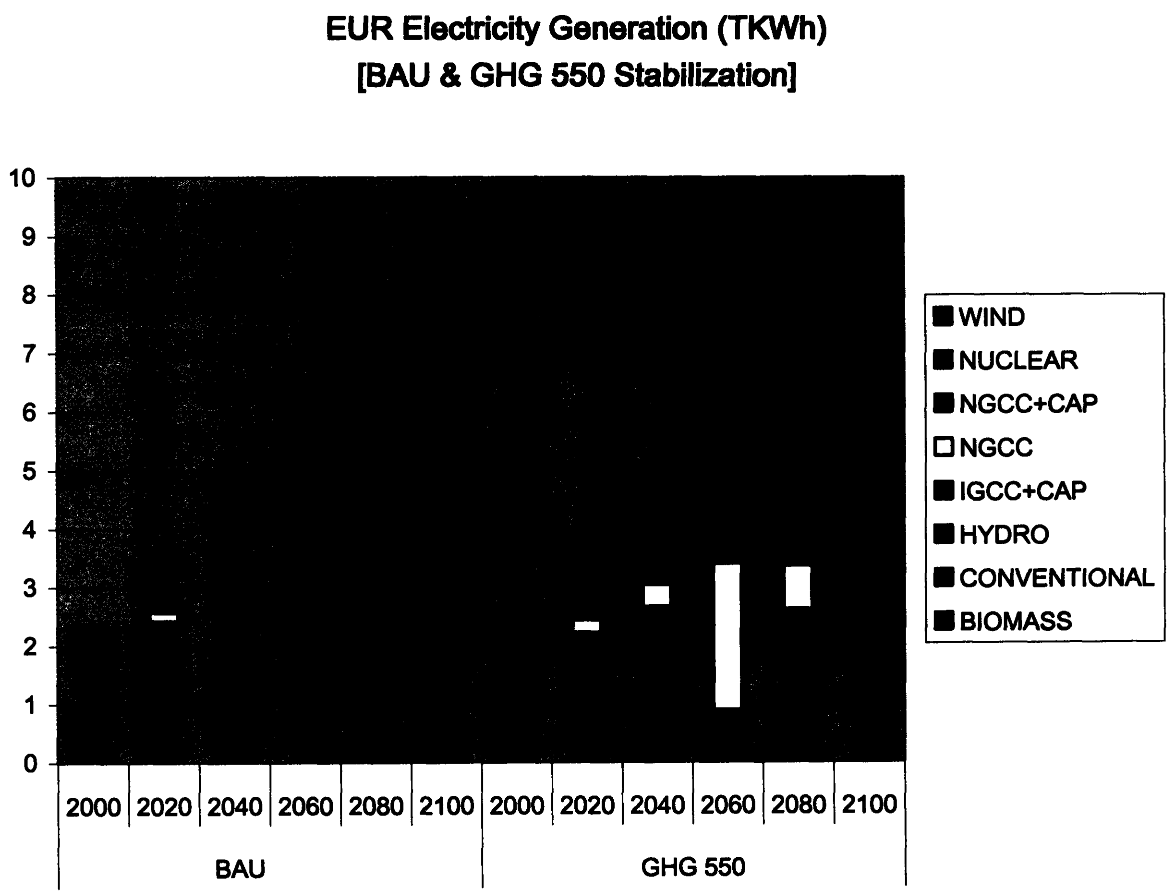
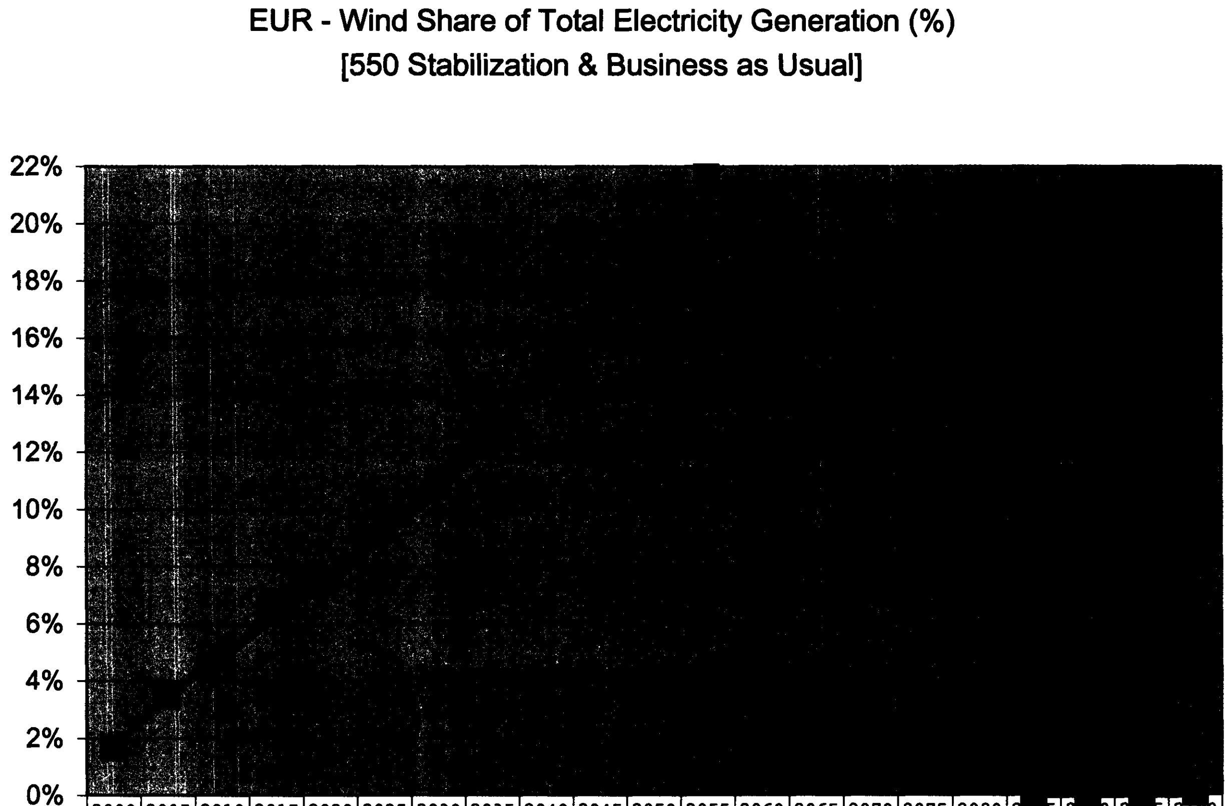


Figure 20 - EUR Electricity Generation (TKWh) – 550 GHG & BAU

We also notice that due to the increasingly tight emissions limits wind energy eventually phases out. NGCC plants that emit carbon are utilized to compensate for the intermittent energy from wind turbines. As a result, in the last and most emissions constrained period we are left with four electricity generating technologies: nuclear, NGCC+CAP, IGCC+CAP and hydro. Both nuclear and hydro do not emit carbon and thus are not penalized by the constraints. The carbon capture technologies utilize the plentiful fossil based resources and are able to produce electricity with a small amount of carbon emitted. If wind could be backed up with a technology cleaner than NGCC, perhaps with NGCC+CAP or IGCC+CAP, it is possible that wind power will continue to contribute to the total electricity generation.



	2000	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060	2065	2070	2075	2080	2085	2090	2095	2100
550	1.7%	3.5%	4.8%	6.4%	7.6%	9.3%	11.1	12.8	14.6	16.6	19.0	21.6	19.1	16.4	15.5	14.1	10.1	0.0%	0.0%	0.0%	0.0%
BAU	1.7%	3.5%	4.7%	6.2%	7.4%	9.0%	10.6	12.1	11.8	11.5	11.1	10.8	10.6	10.4	10.0	9.6%	9.4%	9.3%	9.2%	8.4%	1.5%

Figure 21 - Wind Share of Total Electricity Generation - 550 & BAU

To get a better sense of wind penetration, we turn to Figure 21, which plots wind energy as a share of total electricity generation. The data from the BAU scenario is also plotted for comparison. In the 550 ppm stabilization case wind penetration continues to rise after 2030, eventually peaking at 21.6% in 2065. As we described above, after 2060 the carbon capture technologies start to mature and become competitive and eventually replace most of the existing generation, including all of wind by 2085. On the other hand, wind energy penetration in the BAU scenario peaks in 2035 and declines over time until 2100 when it reaches 0%. GHG gas polices such as the one implemented here in the 550 ppm stabilization scenario are often thought to be beneficial to renewable energies, including wind and solar energy. However, because of the intermittency impacts and the need for compensating backup energy, very strict carbon policies will ultimately favor those technologies that have none or very low carbon emissions. This is described in more detail below.

The next two figures, Figure 22 and Figure 23, show wind generation in detail. The first figure shows the cost structure for wind for a given unit of wind energy produced. The results here are similar to that of the BAU scenario. Because of learning the capital and labor costs associated with the wind turbines become a smaller share of the total generation costs. We also see similar impacts due to increasing penetration of wind. As wind because a greater percentage of the total generation, the amount of backup necessary also increases. In this scenario the wind penetration continues to increase in the later years, causing the share of backup costs to rise. By 2060 roughly 60% the costs associated with producing "compensated wind energy" is from providing the needed backup. This, however, does not necessarily mean that a one for one backup is needed to compensate for the intermittent wind. One must remember that what is being plotted are the relative costs of the inputs, not the electricity generation from the wind and backup. The near one-to-one cost relation at the end of the century is partly attributable to the rising fuel costs, partly to the learning effects and partly to the increasing backup requirements.

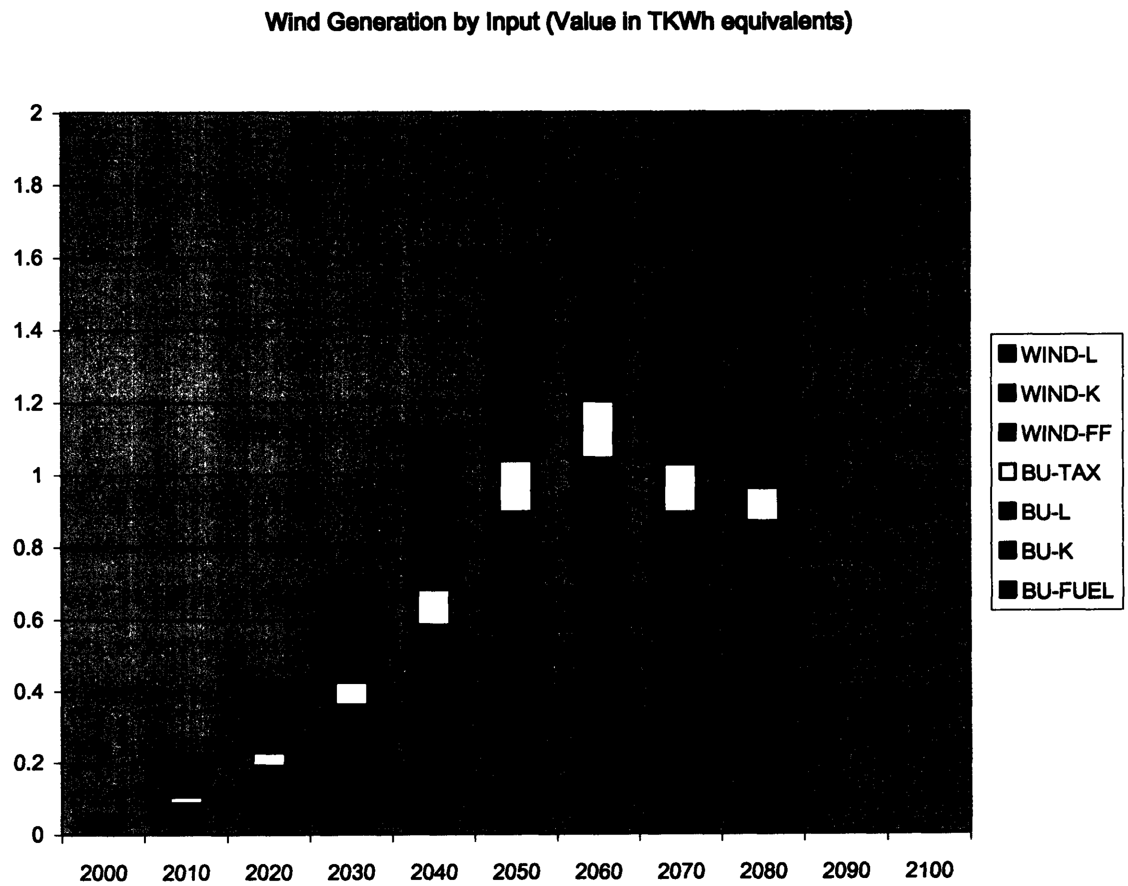


Figure 22 - Cost Percentages for Wind - 550 Stabilization

Wind Generation by Input (% of Total Costs)

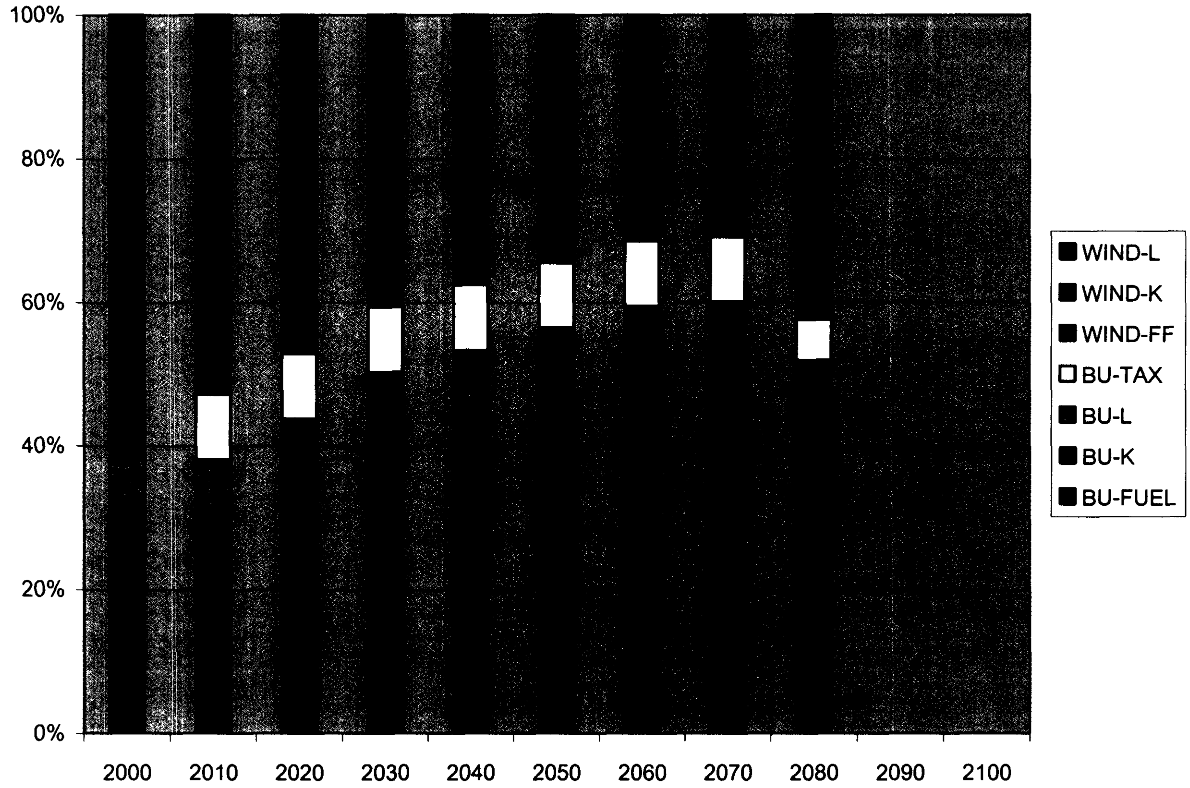


Figure 23 - Cost Structure for Wind - 550 Stabilization

Another interesting phenomenon we see in this scenario is that as conventional generation output drops due to tight carbon policies, the wind penetration increases (even if the total amount of wind generation does not rise). Because of the increase in wind penetration, the cost of wind generation will go up. The net effect is that when total electricity generation is lowered, the amount of wind generation will also be limited because of the backup requirements. In the end, carbon policies that are meant to penalize conventional technologies may in fact will also limit the penetration of wind technologies.

4.3 Scenario 3 – Production Tax Credit

In this scenario we provide a subsidy to reduce the installation and operating cost of wind power. Figure 24 shows the total electricity generation for the EUR region broken down by technology. And Figure 25 compares the electricity generation for the EUR region under this scenario versus the BAU scenario.

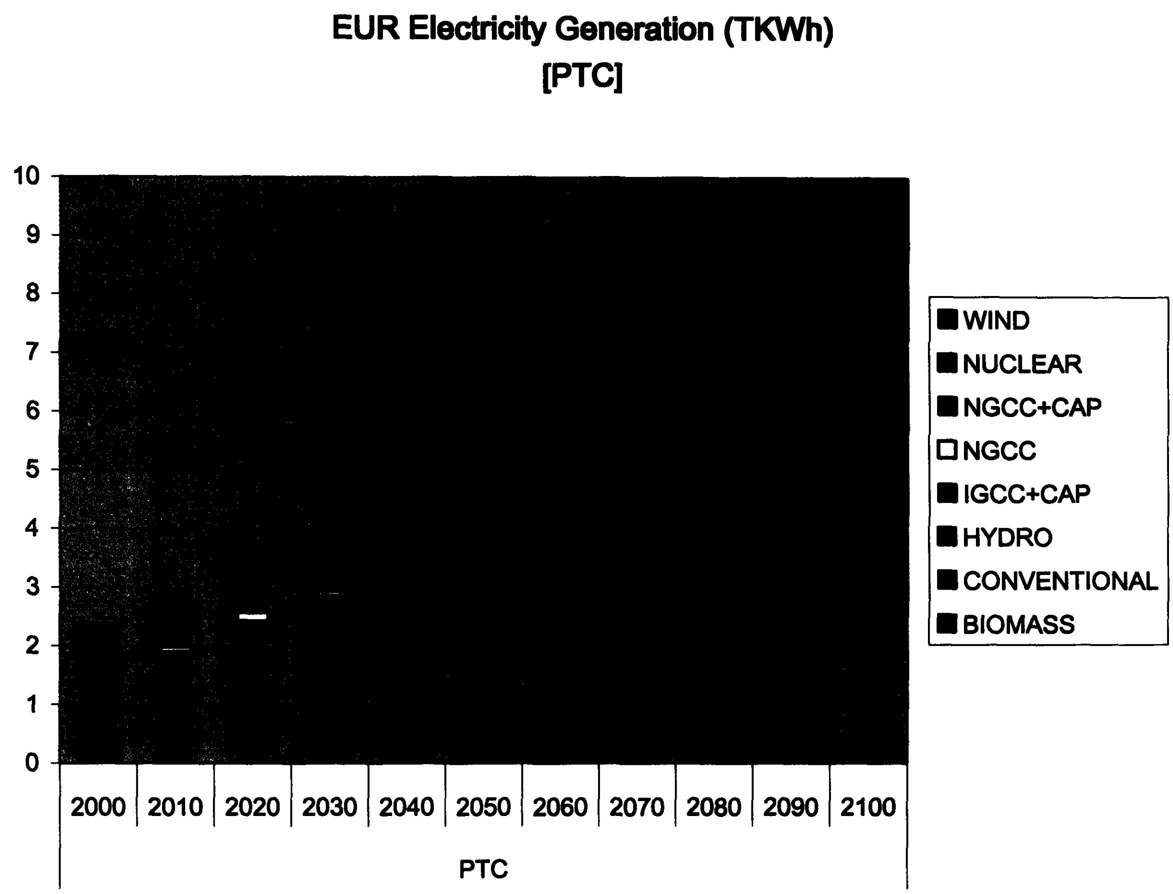


Figure 24 - EUR Electricity Generation (TKWh) – PTC

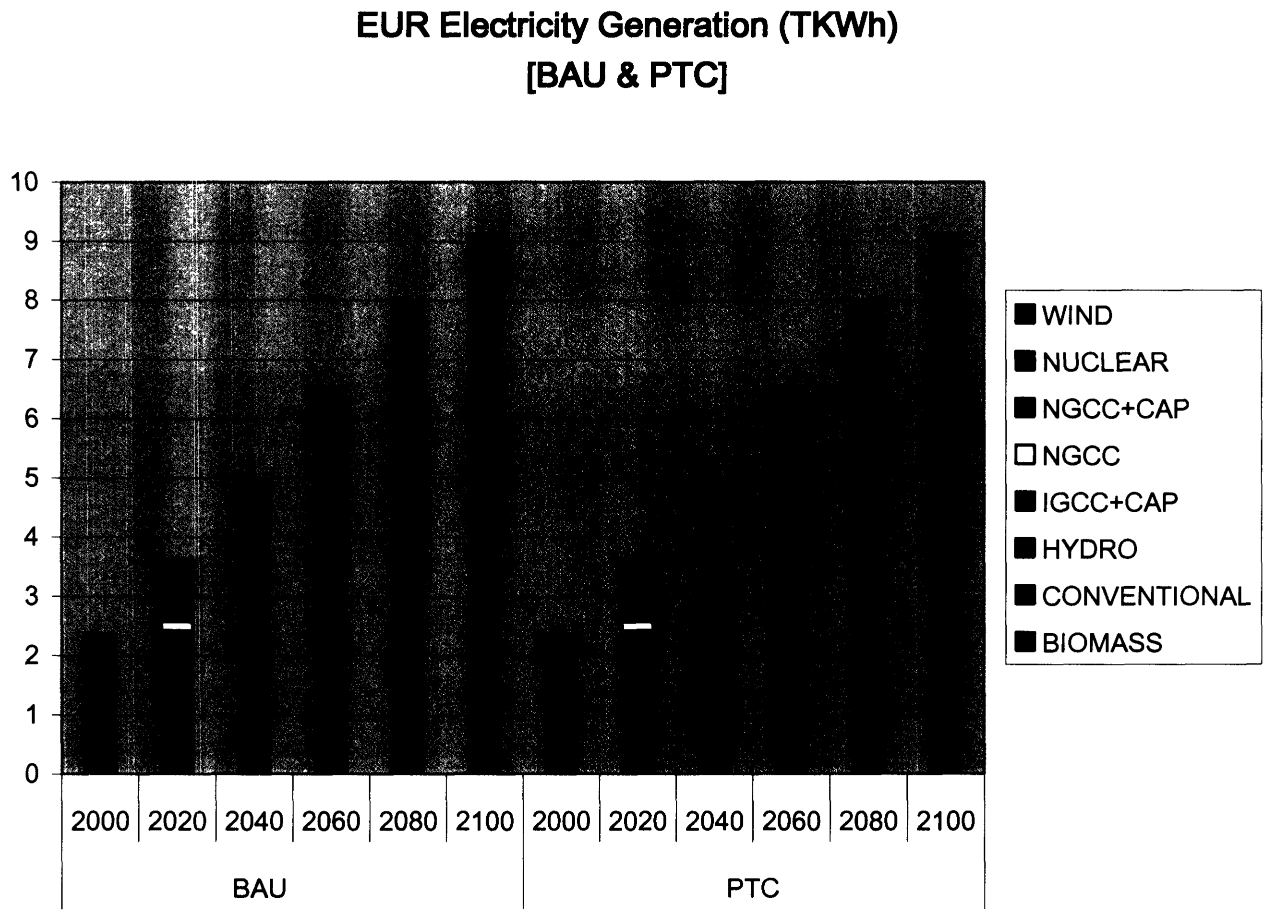
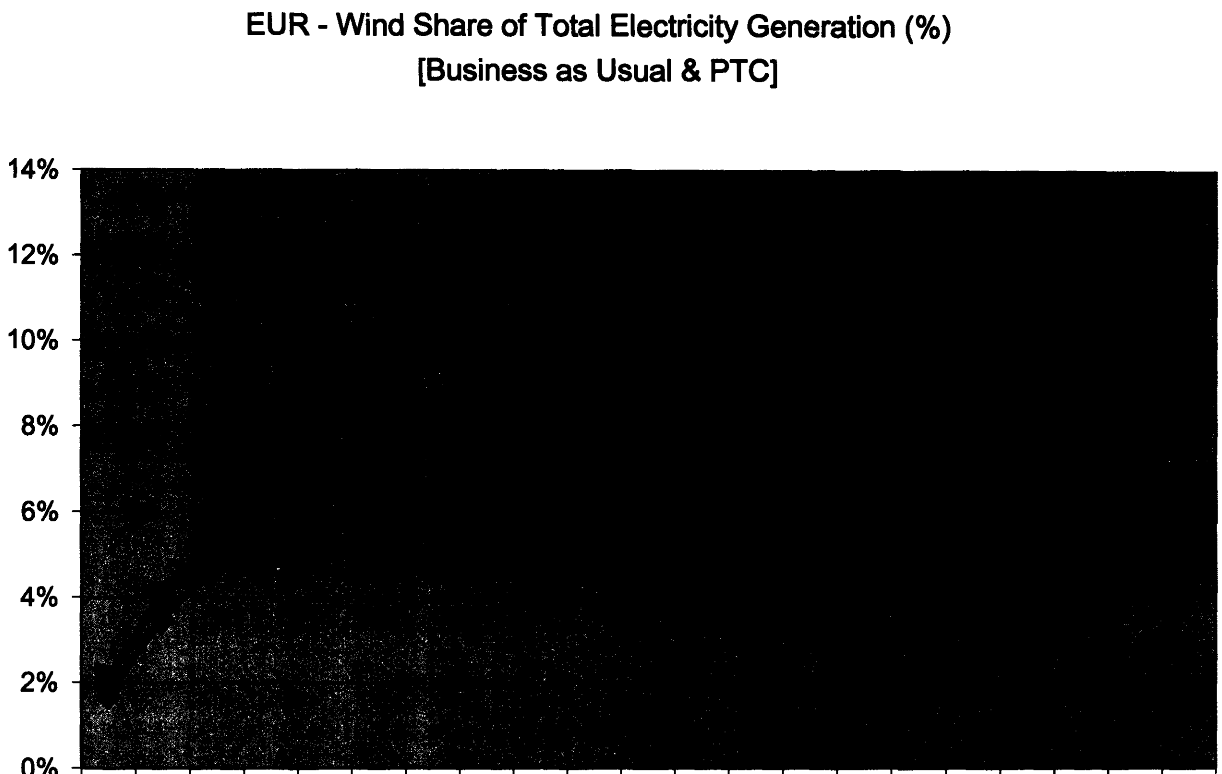


Figure 25 - EUR Electricity Generation (TKWh) - BAU & PTC

In these two charts we can see the differences (or lack of difference) between the scenarios. The production tax credit reduces the cost of wind generation starting in 2000 through 2020. As a direct result, the electricity generation from wind is increased in those periods. When we compare the electricity generation over the those years, we see that the tax credit increased total production from 0.040 TKWh to 0.050 TKWh in 2000, and from 0.139 TKWh to 0.154 TKWh in 2005. Although the absolute production increase is small, the percentage increases are not insignificant.

Production tax credits are meant to incentivize wind production in the early periods in hopes that the additional installations will help the industry mature and lower the costs of production. In this model that long-term effect is minimal. We see that when the tax credit is removed wind generation is identical in the two cases. The total electricity production also remains unchanged. This is because learning effect is calculated based on cumulative global wind generation. In this policy case, I have only applied the PTC to the EUR region. When we add up the additional wind generation the total change in cumulative global generation is small. If we applied the PTC to every region the learning effect will most likely extend beyond the subsidy periods.

To get a better sense of wind penetration, we turn to Figure 26, which plots wind energy as a share of total electricity generation for the BAU and PTC scenarios.



	2000	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060	2065	2070	2075	2080	2085	2090	2095	2100
PTC	2.1%	4.1%	5.2%	6.6%	7.4%	9.0%	10.6	12.1	11.8	11.5	11.1	10.8	10.6	10.4	10.0	9.6%	9.4%	9.3%	9.2%	8.4%	1.6%
BAU	1.7%	3.5%	4.7%	6.2%	7.4%	9.0%	10.6	12.1	11.8	11.5	11.1	10.8	10.6	10.4	10.0	9.6%	9.4%	9.3%	9.2%	8.4%	1.5%

Figure 26 - Wind Share of Total Electricity Generation (BAU, PTC)

There is very little difference between the two scenarios. With a production tax credit we have slightly more wind and thus wind becomes a greater percentage of total generation. Because the total wind production and the wind penetration levels with the PTC are very similar to the BAU scenario, those figures are omitted.

In the next chapter I summarize the work present in this thesis and present suggestions for future research.

CHAPTER 5: Summary and Discussion

As wind energy continues to grow in the coming decades, as it undoubtedly will under the current favorable renewable energy policies, more and more attention needs to be paid to the impacts of adding intermittent sources to the electricity system. In Chapter 1 I highlighted some of the current renewable energy policies that support and incentivize wind energy. The earliest policies gave money to help fund initial wind power investments. Current policies are now moving towards valuing and giving credit for actual contributions to the system. They do not, however, take into account the full impacts of intermittency. Because wind penetration levels have been extremely low, intermittency has not posed any significant problems for the electricity system thus far. However, as total generation grows and wind penetration rises we need to begin taking a closer look at the dynamics of the electricity sector.

In this thesis I documented the changes the changes made to the MIT CGE model in order to better represent intermittent wind power generation. In reviewing the literature I found that in order for wind to be perfectly competitive with other generation technologies we must account for the impacts of degrading wind resources, the impacts of increasing wind penetration and the impacts of learning by doing. Each of these can significantly alter the price of wind energy and hence the rate of technology adoption. The accounting of intermittency is made more difficult because the impact of intermittency is not constant over time. The load carrying capacity of the wind energy system changes as a function of wind penetration and the quality of wind resource also changes as a function of cumulative generation. When wind is modeled as a perfect substitute, the behavior of wind is no longer constrained by the share preserving nature of the model. Wind generation now responds to not only to changes in capital and labor prices but also to changes in carbon policies and the overall generation mix.

Given this structure we can begin to evaluate the many policy drivers that can shift the generation mix of a particular region. Using the MIT general equilibrium model, I analyzed the adoption of wind technology under three policy scenarios. We notice that the rising costs associated of intermittency will limit the ability of wind to take a large share of the electricity market. As wind penetration increases, a greater cost is imposed on the wind generator in order to compensate for the intermittency impacts, making wind energy more expensive. Because the model explicitly accounts for the impacts of intermittency, the wind generator is in effect making investment decisions based on the marginal cost of adding additional intermittent sources to the system.

In a business as usual scenario with no wind subsidies or carbon constraints, wind energy generation rises to 0.80 trillion KWh in 2090 and accounts for 9% of the total electricity generation. In a scenario that stabilized greenhouse gases at 550 parts per million, the carbon penalties are high enough to motivate the entry of 1.16 trillion KWh of wind energy that accounts for 22% of the total electricity generation. I also investigated the effects of a production tax credit subsidy for wind generation. In this scenario wind energy generation increases by average of 12% over the base case scenario during the years the policy was in effect. However, when the subsidy tapers off, wind generation in later periods remains unchanged.

With this structure in place, further analysis can be done to evaluate renewable energy policies. One could for example look at the welfare costs of implementing a renewables portfolio standard or production tax credits under carbon-constrained scenarios. These analyses will help us better understand the value of investing in wind energy now in order to reduce total generation costs (and negative environmental impacts) in the future.

Replacing the world's fleet of coal and gas plants with sustainable power sources such as wind and solar can go a long way towards reducing our net greenhouse gas emissions. However, depending on how we compensate for the ever-greater impacts of intermittency, whether it is by backup gas-fired plants or short-term storage facilities, the path to a carbon-free world may not be rosy as initially perceived. In this paper I presented a first look at integrating intermittency into a computable general equilibrium model. The rapid expansion of wind generation in countries such as Denmark and Germany will provide us with a great learning opportunity to better understand the impacts of intermittency and how we can best account for and deal with those impacts.

References

Babiker, M., J. Reilly, M. Mayer, R. Eckaus, I. Sue Wing and R. Hyman (2001). The MIT Emissions Prediction and Policy Analysis (EPPA) Model: Revisions, Sensitivities, and Comparisons of Results. MIT Joint Program on the Science and Policy of Global Change, Report No. 71 (http://mit.edu/globalchange/www/MITJPSPGC_Rpt71.pdf).

Brenkert, A, Smith, S, Kim, S, Pitcher, H. Model Documentation for the MiniCAM. The Joint Global Change Research Institute, Pacific Northwest National Laboratory. 2003.

Burtraw and Palmer, "Electricity, Renewables, and Climate Change: Searching for a Cost-Effective Policy" Resources for the Future, Washington D.C. 2004

Cody, G., Tiedje, T. A Learning Curve Approach to Projecting Cost and Performance in Thin Film Photovoltaics. *Proceedings of 25th Photovoltaic Specalists Conference,* IEEE, 1521-1524 1996.

Coelingh, J.P., Van Der Ree, B.G.C., Van Wijk, A.J.M., "The Hourly Variability in Energy Production of 1000MW Wind Power in the Netherlands," *Proceedings of European Wind Energy Conference.* July 1989.

Danish Wind Energy Association (DWEA) "Annual Energy Output from a Wind Turbine: Capacity Factor" http://www.windpower.org/en/tour/wres/annu.htm 2003.

Department of Energy, U.S. "Wind Energy Resource Atlas of the United States." Prepared by the Pacific Northwest Laboratory. Richland, Washington. 1986.

Edmonds, J., M. Wise, H. Pitcher, R. Richels, T. Wigley, and C. MacCracken. "An Integrated Assessment of Climate Change and the Accelerated Introduction of Advanced Energy Technologies," *Mitigation and Adaptation Strategies for Global Chang.* 1997

Electric Generation Expansion Analysis System (EGEAS), EPRI EL-2561, Volume 1, Project 1529-1, Final Report. August 1982.

Energy Information Administration, Emissions of Greenhouse Gases in the United States 2003. http://www.eia.doe.gov/oiaf/1605/ggrpt/pdf/057303.pdf. 2004

Energy Information Administration. *The National Energy Modeling System: An Overview.* Energy Information Administration: Washington D.C. DOE/EIA-0581. 2004.

Energy Information Administration. Model Documentation: Renewable Fuels Module of the National Energy Modeling System. Office of Integrated Analysis and Forecasting. Washington, DC. Available at: http://tonto.eia.doe.gov/FTPROOT/modeldoc/m069(2002).pdf February 2002

Flaim, T., Hock, S., *Wind Energy Systems for Electric Utilities: A Synthesis of Value Studies*, SERI/TR-211-2318. Solar Energy Research Institute. May 1984.

Fraenkel, P.L. "New developments in Tidal and Wavepower Technologies." In *Proceedings of the Silver Jubilee Conference: Towards a Renewable Future.* Conference C73 of the Solar Energy Society, May 13-15, Brighton, U.K. 1999.

Garver, L.L., "Effective Load Carrying Capability of Generating Units," *IEEE Transactions on Power Apparatus and Systems*, Vol. PAS-85, No. 8. August 1966.

Global Wind Energy Council (GWEC), "GLOBAL WIND POWER CONTINUES EXPANSION: *Pace of Installation Needs to Accelerate to Combat Climate Change*" http://www.ewea.org/documents/0304-Global%20Wind%20Energy%20Markets%20-%20FINAL.pdf (2005)

International Energy Agency (2000). *Experience Curves for Energy Technology Policy.* Paris, OECD/IEA.

Halberg, N., "Wind Energy Research Activities of the Dutch Electricity Generating Board" Proceedings of the European Community Wind Energy Conference, Madrid, Spain (September 1990).

Hertel, T., editor. *Global Trade Analysis: Modeling and Applications.* New York: Cambridge University Press. 1997.

Hyman, R.C., J.M. Reilly, M.H. Babiker, A. De Masin and H.D. Jacoby (2003). Modeling Non- CO2 Greenhouse Gas Abatement. *Environmental Modeling and Assessment*, 8(3): 175-186.

Iowa Department of Natural Resources. "Wind Hybrid Electricity Applications" March, 2001 Available at: http://www.state.ia.us/dnr/energy/MAIN/PUBS/WHEA/DNR%20Hybrid%20Final%20Edit.pdf

Jacobson, Mark Z. and Gilbert M. Masters, The Real Cost of Wind Energy *Science* 2001; 294: 1000-1003.

Johnson, G.L. *Wind Energy Systems*, Prentice-Hall, Englewood Cliffs, N.J. 1985.

Korpaas M, Hildrum R, Holen AT. "Hydrogen energy storage for grid-connected wind farms" Proceedings of the Sixth IASTED International Conference on Power and Energy Systems, pp 590-594. Rhodes, Greece, July 2001

Korpaas M, Hildrum R, Holen AT. "Operation and sizing of energy storage for wind power plants in a market system" International Journal of Electrical Power & Energy Systems, vol. 25, 2003, pp 599-606.

McFarland, J., J. Reilly and H. Herzog. Representing Energy Technologies in Top-down Economic Models Using Bottom-up Information. *Energy Economics*, in press; MIT Joint Program on the Science and Policy of Global Change Report No. 89 (http://mit.edu/globalchange/www/MITJPSPGC_Rpt89.pdf). 2004.

Parsons, B. M Milligan, B Zavadil, D Brooks, Grid Impacts of Wind Power: A Summary of Recent Studies in the United States

Reilly, J., H. Jacoby and R. Prinn (2003). Multi-Gas Contributors to Global Climate Change: Climate Impacts and Mitigation Costs of Non-CO2 Gases. Pew Center on Global Climate Change, Arlington, VA.

Richardson, D. and McNerney, G. "Wind Energy Systems" *Proceedings of the IEEE*, Vol. 81, No. 3, March 1993.

Schienbein, L.A. "Energy Storage and Wind Energy Conversion Systems," *International Journal of Global Energy Issues*, IX No. 3, 1997

Smekens, K.E.L. “Response from a MARKAL technology model to the EMF scenario assumptions.” Energy Economics, Volume 26, Issue 4, July 2004, Pages 655-674.

Smith, D.R. and Ilyin, M.A., "Wind Energy Evaluation by PG&E," Pacific Gas and Electric Research and Development, San Ramon, California. 1990.

Smith, J.C., DeMeo, E. A., Parsons, B. & Milligan, M. Windpower impacts on electric power system operating costs: summary and perspective on work to date. Proceedings of Global Wind Power Conference GWPC ’04, Chicago, USA. April 2004.

Office of Fossil Energy, US Department of Energy (2001); see http://fossil.energy.gov/coal_power/special_rpts/market_systems/market_sys.html

Wan, Y., and Parsons, B. Factors Relevant to Utility Integration of Intermittent Renewable Technologies, National Renewable Energy Laboratory, Golden, CO. Report NREL/TP-463-4953. August, 1993.

WindIndustry. Renewable Electricity Standards http://www.windustry.com/resources/legislation.htm

United Nations Development Programme. World Energy Assessment: Energy and the Challenge of Sustainability. UNDP. 2000.