Impacts of Large Quantities of Wind Energy on the Electric Power System

by

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Abstract

Wind energy has been surging on a global scale. Significant penetration of wind energy is expected to take place in the power system, bringing new challenges because of the variability and uncertainty of this renewable resource. Therefore, the understanding of how wind energy could affect a power system is of great significance to system operators, regulators, investors and policy makers.

This thesis explores both the long-term and the short-term potential impacts of large quantities of wind energy on power systems. Two computer based models and an analytical model are used or developed as the primary tools for this thesis. Among the models, the ReEDS model is used to project the power system capacity expansion for the ERCOT case and the contiguous US case, under different CO2 policy scenarios, for the long-term analysis. The Memphis model is used to simulate in high resolution the operation of a well adapted system for both the ERCOT case and the Spanish case, for the short-term analysis. Sensitivity analyses are also performed to investigate the responses of a power system to different penetration levels of wind energy, as well as to operating reserve requirements. Further, the representation at the operation level in ReEDS is assessed by benchmarking with Memphis.

It is concluded in the thesis that in the long term, wind energy is less likely to grow without CO2 emission restrictions. The power system could experience significant transition to one that is sufficiently reliable to accommodate a strong penetration of wind energy. Sufficient investment in flexible generation capacity will be necessary to back wind energy. In the short term, an increase of wind energy will displace the marginal technology. Different operating reserve requirements also affect the decision of generators between producing and being idle to provide reserves. Therefore, for system security and reliability, adequate regulatory and policy measures should be adopted to orient investment and operation decisions. Last, the benchmarking results show that ReEDS provides fair representations of the power system at the operational level.

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I would like to extend my sincere thanks to the faculty, staff and students from the MIT Energy Initiative and ESD /TPP and: Mr. Tony Meggs and Mr. Daniel R. Cohn, from whom I have always received encouragement and support; Prof. Dava Newman and Ms. Sydney Miller, for their great patience and all the efforts to have made TPP a great program where I have spent tons of happy time, and so on.

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CHAPTER 1. INTRODUCTION

1.1 Motivation

Wind energy has been one of the fastest growing renewable energy sources in the past decade. This surge of wind energy penetration has been driven by many factors. First, technology improvement and cost reduction, along with its zero fuel cost, have significantly enhanced wind energy's competitiveness both technically and economically. Second, with zero emissions, wind energy is considered a sound option for the achievement of CO2 emissions reduction and to address other environmental concerns, such as water pollution and waste disposal. Third, wind energy also contributes to a solution that addresses the concerns about energy security. Moreover, policy instruments such as renewable tax credits, renewable portfolio standards and feed-in tariffs also have been key factors in promoting the growth of wind energy. Therefore, wind energy is expected to have a bright future in the energy world.

As larger wind energy penetration takes place in the electric power system, it brings challenges as well. It adds variability and uncertainty to the power system, affecting the dispatch of generation from other technologies. In the short term, during which the installed capacity of other existing generation technologies cannot be modified, wind energy penetration affects system operation in both generation dispatch and ancillary services; in the long term, during which the additions and retirements of the installed capacity of other technologies could happen, wind energy penetration further affects investment decisions. In either circumstance, sufficient understanding of the potential impacts wind could bring into the power system is indispensible for regulators and policymakers to make the most pertinent regulations and policies and to send out the right signals to stakeholders.

In the past two years, I have been participating in the Future of Natural Gas study, an MIT interdisciplinary study examining the role of natural gas for meeting future demand under CO2 emission constraints. Recognizing the potential significant roles of intermittent renewable energy in the power system, the Future of Natural Gas study has explored the impacts of the variability and uncertainty introduced by large quantities of wind and solar, on both the levels and patterns of demand for natural gas in power generation (MIT Energy Initiative, 2010). Although the conclusion in the Future of Natural Gas study report focuses on the impacts of wind and solar on natural gas, the research has a wider scope beyond what is presented in the report of the MIT study.

When conducting the research on the impact of wind energy, I have had the opportunity to use two computer-based models, the ReEDS model, which has been developed by the US National Renewable Energy Laboratory, and the Memphis model, which has been developed by the Institute for Technological Research at Comillas University in Spain. Therefore, in a world where a promising future of wind energy is expected, having the opportunity of participating in the Natural Gas Study and conducting research on the impacts of wind energy in the power system have been particularly interesting to me and have motivated me to look further into the challenges associated with the increasing penetration of wind energy.

1.2 Thesis research questions

In order to make reasonable simplifications and to investigate in depth certain key aspects of the impacts of large quantities of wind energy in the power system, this thesis limits its scope to the following aspects:

- What is the path for an electric power system toward a future where large quantities of wind energy are deployed to meet the electricity demand under certain CO2 emission constraints? In particular, how does the installed capacity of conventional technologies in the system evolve to guarantee reliability?
- In a CO2 restricted future where large quantities of wind energy take place, how does a system operate? Moreover, how does the level of wind penetration affect the operation of a power system and how does the system respond to different operating reserve requirements?
- How precisely does the ReEDS model compute operation of various technologies? What representation of the several aspects of operation of a power system could be improved in ReEDS?
- This thesis does not consider the impacts of wind energy on transmission, although admittedly it is an important aspect to the development of a power system with a strong wind penetration.

1.3 Objectives

Considering the above, the objectives of this thesis include:

1) Developing a general framework and methodology to assess the short term and the long term impacts of large quantities of wind energy on the electric power system;
2) Identifying the long-term response of a power system to the introduction of large quantities of wind energy both in terms of capacity investment and generation dispatch patterns under different policy scenarios;
3) Analyzing the short-term response of the power system operation to different levels of large wind penetration and different levels of operating reserve requirements in the presence of large volumes of wind energy;
4) Benchmarking generation dispatch results computed by the ReEDS model for a future year, with the results computed by the Memphis model;
5) Making recommendations to power system regulators and policymakers regarding the integration of a large penetration of wind energy, based on the results of the previous analyses.

1.4 Approaches

In the short term, a power system responds to the change of the penetration of wind energy through operation. In the long term, not only operation but also investment in new capacity can be affected with the introduction of a significant amount of wind energy. Therefore, the long-term and the short-term impacts of large quantities of wind energy on the power system are related yet distinctive aspects to analyze. For such purposes, three models are used in this thesis as the basic tools to answer the research questions.

The Regional Energy Deployment System model (ReESD) is used in this thesis primarily for the long-term impact analysis since it is a capacity expansion GAMS model of the US electric power system, with specific capabilities to represent the US wind resources and the characteristics of wind energy. Under different CO2 scenarios, the model projects the capacity expansion of the US power system over the period of 2006 to 2050. For the long-term analysis, the ERCOT power system has been used as a case study to be analyzed in detail. The complete US national level power system is also studied, but not so intensively.

The Memphis model is used in this thesis to analyze the short-term impact of wind energy for a future snapshot year in which the capacity mix of the power system has been projected by ReEDS. This model represents the day-ahead unit commitment process and simulates hour-by-hour the real time operation of a power system, capturing the chronological interplay of generation dispatch between wind energy and other technologies in the system. For this part of the analysis, both the ERCOT system and the Spanish system are used as case studies. Because the Memphis model is more realistic in simulating the operation of a power system, the results obtained by Memphis are further used as a benchmark to assess the accuracy of ReEDS when calculating the system operation for ERCOT.

In addition, an analytical model has been developed to represent the electric power system under both central planning and market-based frames, by separately looking at the capacity credits, average availability and energy production of wind and other conventional technologies. The analytical model facilitates the exploration and understanding of the fundamental rationales behind the observations obtained by ReEDS. Figure 1-3 shows the structure of the complete analysis performed in this thesis.

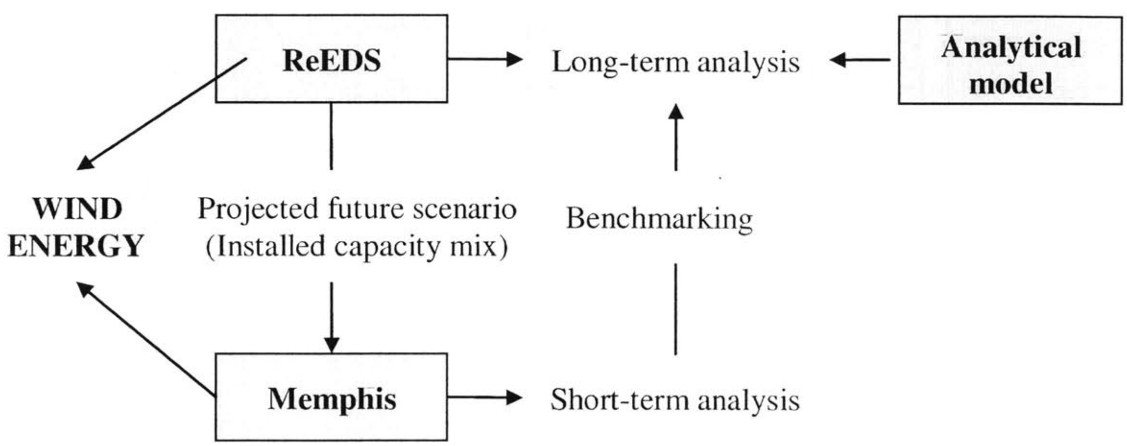

Figure 1-1 Research approach

1.5 Thesis Overview

Chapter 2 provides the necessary background information: the global wind energy status, the characteristics of wind energy: variability and uncertainty in particular, and several important concepts of the power system capacity planning and operation that are particularly relevant to this thesis.

Chapter 3 presents in the detail the approach that has been adopted for this thesis, including the description of the ReEDS model and the Memphis model, the main parameters, inputs and outputs of the models. This chapter also develops the analytical model.

Chapter 4 evaluates the long-term impacts of large quantities of wind energy on the electric power system. Different policy scenarios are defined and analyzed for the ERCOT system and the contiguous US power system. Sensitivity analysis is performed to further quantify such impacts.

Chapter 5 studies the short-term impacts of large quantities of wind energy on the power system operation. Discussions on the dispatch pattern and operating reserves are conducted for ERCOT and the Spanish power system in particular. Sensitivity analysis is performed to further quantify such impacts.

Chapter 6 benchmarks the results of the operation of various technologies obtained by ReEDS with the simulation results obtained by Memphis for the same ERCOT 2030 case.

Conclusions from the thesis are summarized in Chapter 7.

CHAPTER 2. BACKGROUND

2.1 Introduction

By the end of 2009, the world installed capacity of wind energy totaled 158.5 GW, compared with 17GW a decade ago in 2000. Figure 2-1 shows the global installed capacity of wind energy since 2000 (GWEC, 2010). As has been mentioned earlier in Chapter 1, the dramatic growth of wind energy has been driven by several factors, including environmental concerns, energy security concerns, the increase in efficiency and the improvement of reliability of wind turbines, as well as the technology advancement that has brought down the capital costs to make wind energy more economically competitive with other generating sources.

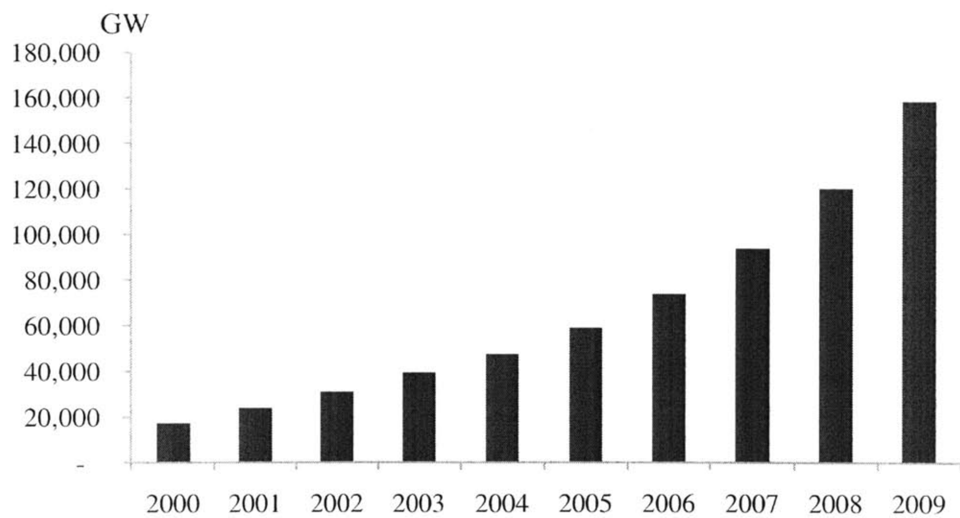

Figure 2-1 Global cumulative installed capacity of wind energy (GW)

This trend of wind growth has drawn wide interests in understanding the impacts of wind energy as its penetration is expected to increase to a more significant level. Two countries, the US and Spain, are analyzed as case studies in this thesis.

Only very recently has the US become a leader in the deployment of wind energy. It now tops all the other countries in terms of installed capacity. In 2009, despite the global economy downturn and the recession in energy consumption, the installed capacity of wind energy in the US still increased by 39%, with installed grid-connected capacity totaling 35GW (GWEC, 2010). According to the American Wind Association, 36 out of the 50 US states now have utility-scale wind installations and 14 states have more than 1,000 MW of wind capacity installed (AWEA, 2010). Texas installed the largest amount of new capacity of wind in 2009, reaching a total installed wind capacity of 9,405 MW (AWEA, 2010). In 2009, the share of wind electricity generation in the US is 1.8%, an increase from 1.3% in 2008 (AWEA, 2010).

Spain led the European countries with an addition of 2.5 GW of installed wind generation capacity in 2009. Wind energy is now the third largest generating source in Spain. It produced 36.2 TWh in 2009, a share of 14.5% of the country's total demand, compared to 11.5% in 2008 (GWEC, 2010).

This chapter introduces the characteristics of wind energy and how these characteristics could affect the power system on different time frames. A review of other studies about the integration of wind energy into the power system is briefly presented as well.

2.2 Characteristics of wind energy

2.2.1 Introduction

The technology of wind turbines has improved greatly in the past. Currently, the wind turbine usually has three-bladed rotors with diameters of 70 to 80 meters and can be 60 to 80 meters in height. In general, a wind turbine will start producing power when wind blows at the speed of 5.4 m/s and will reach maximum power output at about wind speed 12.5 m/s–13.4 m/s. If the wind blows too strong, the turbine may have to be turned off so as not to get damaged. A DOE study shows that the turbine will pitch or feather the blades to stop power production and rotation at about 22.4 m/s (DOE, 2008). Now a large wind turbine can reach a maximum output of up to 5MW and the capacity of a large wind plant can be up to several GW (NERC, 2009).

Despite the technology improvement of wind turbines, the use of wind is mostly decided by the characteristics of the natural resource. Wind energy is considered a type of intermittent energy source, meaning that its output is driven by environmental conditions mainly outside the control of the generator or the system operators (Luickx, Delarue, & D'haeseleer, 2008). Two major aspects of wind characteristics are particularly challenging to the integration of large quantities of wind energy into the power system: variability and uncertainty. These two attributes of wind distinguish wind largely from conventional energy sources, such as coal plants or nuclear plants, the output of which are not dependent on the external constraints of any natural resource.

2.2.2 Variability of wind

Some of the wind patterns are driven by daily thermal cycles, whereas others are driven primarily by meteorological atmospheric dynamics (NERC, 2009). The variability of wind should be considered on a certain timescale and a given size of the geographic area, as the resulting outcome and impacts could be largely different. Depending on the natural environment, wind can be highly variable on all timescales: minutes, hours, days, seasons and years. Shorter timescale usually refers to the range of seconds to days, whereas longer timescale refers to the range of seasons to years. The variation of wind in absolute value usually increases in a longer time span as wind can be very strong in one season but extremely low in another season. The yearly pattern could also be significant. Figure 2-2 shows how the output of a wind turbine can vary between zero and the wind turbine's maximal capacity in a single day.

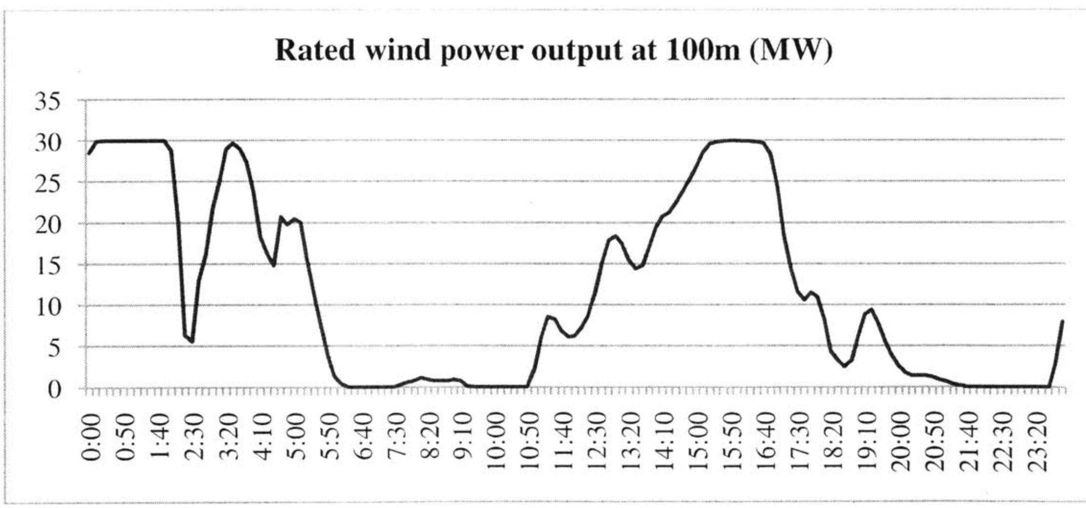

Figure 2-2 Sample wind output profile at 100m
(Data source: WWITS study. Wind turbine ID: 8886, June 2, 2006, CO)

In the shorter time frame, subtle fluctuation of wind speed happens all the time but can be compensated as it is transformed into energy by the wind turbine (IEA, 2005). On a minute-to-minute time scale, the output of wind turbines within a reasonably large geographic area can be stable. Changes of the aggregate output take place in a gradual pace over an hour or more. At the same time, it is important to differentiate the variability of a single wind turbine and the aggregated performance of wind energy in a power system. The output of a single wind turbine can be highly variable on the shorter time scale, but the variation can be smoothed out by geographic diversity, which has been confirmed by many studies (IEA, 2005) (EnerNex Corporation, 2010), (NERC, 2009) or (IEA, 2007). To what extent this smoothing effect exists largely depends on the size of the area and the distribution of these wind turbines. The diversity of the sites of wind turbines undoubtedly adds to the smoothing effect.

In the longer time frame, however, all wind resources in a large geographic area can be seen to be ramping in the positively correlated direction (NERC, 2009). Therefore, on the longer time scale, the challenges introduced by the variability of large quantities of wind, in absolute number, could be very large, which impose additional challenges to system reliability when no wind energy is available for a relatively long period. The following section will further discuss about this issue.

In addition, with higher penetration levels of wind energy, the aggregated variability of the power system is expected to increase, resulting in more requirements on conventional generation resources to cope with such variability. This will be further discussed later in this chapter. Moreover, these attributes of wind should also be considered together with the variation of demand. Since weather and climate are a common factor influencing the pattern of electricity energy demand and wind pattern, the correlation between wind and demand may not be negligible in some cases. Therefore, it is important to sample demand series and wind output series taking into account the correlation between them for a specific region.

2.2.3 Uncertainty of wind

Since wind output is dependent on the natural environment, there is almost always a deviation in the prediction of wind from what is actually available in real time. Wind forecast plays an important role for wind generators and system operators to plan in advance. However, compared with load forecast, less experience exists about wind forecast. Although significant improvement in the forecasting technology has taken place in the past decades and the overall profile of wind production can be predicted most of the time, large forecast errors can still occur both in the level and in the timing of the wind input (IEA, 2007). In contrast, although conventional generating technologies are also subject to uncertainties such as forced outages, the extent of the uncertainty is much smaller than that of wind. Therefore, wind forecast error brings an additional challenge to the integration of wind energy into the power system.

The two distinct characteristics of wind, variability and uncertainty, may require different patterns of power system operation and planning, when wind energy penetrates in large quantities. The impacts will be discussed in the following sections.

2.3 Impacts of wind on the power system

2.3.1 Terminologies

Because wind shows different patterns when considered in various time scales, the dominant impacts of wind on the electric power system also vary in the short term and in the long term. In the short term, the system is not able to respond to changes in wind production level by modifying the generating capacity mix. The influences are reflected through the need of modifying generation dispatch pattern and ancillary services. In the long term, in contrast, capacity addition and retirement could happen and capacity adequacy becomes the primary concern. Several concepts are important to the discussions both in the current and later chapters and they are introduced first.

Operating reserves

A number of services are necessary for power systems to maintain certain levels of stability, security and reliability. The operating reserve is crucial in providing such service. On top of the units that are actually generating, a hierarchy of reserves are needed and required to ensure the short-term security in a power system. Different systems have adopted different conventions in the terminologies of reserves.

In European countries, reserves are often classified as primary reserve, secondary reserve, and tertiary reserve. Primary reserves are activated to stabilize the frequency of a bulk electric system in case of a disturbance. This type of reserves usually responds within 30 seconds (European Commission, 2006, EnerNex Corporation, 2010). Secondary reserves are activated by the centralized automatic generation control (AGC) of the control areas to restore the scheduled load flows between control areas and to free the system-wide primary reserves, while tertiary reserves are called upon by the system operators and are activated manually to replace the secondary reserves. They usually refer to units that can provide quick-start capability (Just & Weber, 2008).

In the US system, reserves are usually classified as regulating reserve, load following reserves and contingency reserve (NERC, 2009). A contingency refers to the unexpected failure or outage of a system component, such as a generator, a transmission line, a circuit breaker, a switch, or another electrical element. Therefore, contingency reserves are ready to be used in the event of such a contingency. In the formal NERC definition, this term refers to the provision of capacity deployed by the balancing authority to meet the disturbance control standard (DCS) and other NERC and regional reliability organization contingency requirements (EnerNex Corporation, 2010). NERC requires contingency reserves respond within 10 min (NERC, 2009). The definition of regulating reserves more or less overlaps with the definition of both primary and secondary reserves. Load-following reserves do not officially appear in NERC's glossary but are very commonly used. They sometimes include both secondary and tertiary reserves. They can be supplied from generation, controllable load resources, or coordinated adjustments to interchange schedules (Just & Weber, 2008). This type of reserves can include both spinning and non-spinning reserves. Spinning reserves are generating units that are up and running, but below their maximum output, and that are synchronized to the system and fully available to serve load within the disturbance recovery period. Sometimes in the literature the function of spinning reserves happens to be the same as for contingency reserves (GE ENERGY, 2005). As opposed to spinning reserves, a non-spinning reserve is composed of generating units that is not in operation at a given moment but capable of serving demand within a specific time (NERC, 2009).

Firm capacity

In the long term, it is the overarching goal to have sufficient generating resources and reliability characteristics to meet future demand in a reliable and economic manner. A certain margin of capacity is always maintained above the highest demand requirements to maintain reliability under unexpected system conditions. However, because of the potential unavailability of the generating resources, such as scheduled maintenance or a forced outage, the nameplate capacity of each generating unit cannot be fully reliable at all time. Firm capacity, instead of the total nameplate installed capacity, is therefore used to calculate the required margin. Firm capacity is the amount of capacity available for production which can be (and in many cases must be) guaranteed to be available at a given time. Therefore, firm capacity is the discounted capacity from the nameplate capacity of various generating units to reflect the potential unavailability of the resource at high risk times (NERC, 2009).

Capacity credit

The per unit contribution to the overall firm capacity in a system on an annual basis could vary significantly from technology to technology because of the characteristics of these technologies and such contribution is measured by the concept of capacity credit (also called capacity value) (EWEA, 2009).

Capacity factor

Capacity factor is defined as the ratio of the actual power production over a period of time and the output if it had operated at full nameplate capacity. Capacity factor reflects directly the wind resource potential in the region. Calculating capacity factor can also give the indication of the wind and load correlation.

Availability factor

Availability factor of a generator is the amount of time during which it is able to produce electricity over a certain period, divided by the amount of time in the period. Newer plants usually have higher availability factor. Plants that are run less frequently have higher availability factors because they require less maintenance (Banakar, Luo, & Ooi, 2008).

The concepts of capacity credit, capacity factor and availability factor will be further discussed and employed in Chapter 3 for the development of the analytical model.

2.3.2 Impacts of wind energy on operating reserves

The integration of large quantities of wind energy could affect system stability on the timescale of seconds, affect regulating and load following on the timescale of seconds to hours, affect unit commitment on the timescale of hours to days, transmission adequacy on the timescale of days to years and affect generation capacity adequacy on the timescale of years and beyond. Figure 2-3 shows the impacts of large quantities of wind energy under different timeframes.

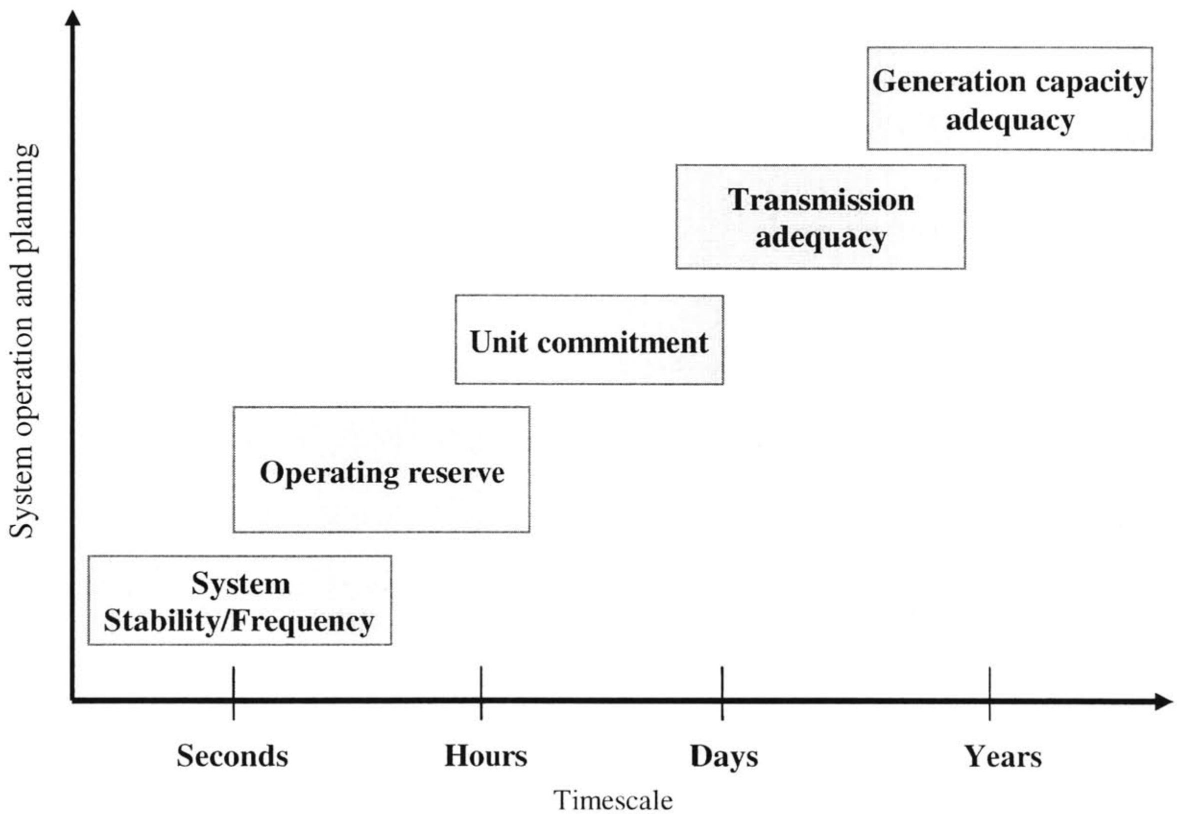

Figure 2-3 Impacts of large quantities of wind energy on the power system in various timeframes

Impacts of wind energy on operating reserves

The impacts of wind energy on operating reserves are a short term impact, often estimated by statistical methods that combine the variability and uncertainty of wind with the variability of load. Generally, it is considered that wind energy does not have an impact on contingency reserves (EnerNex Corporation, 2010) (GE ENERGY, 2005). However this is subject to the condition that the total output of a wind plant or the aggregate output of multiple wind plants in a specific area is not larger than the current contingency or that it cannot fail in a few minutes.

The impacts of wind on primary reserves are not obvious. The automatic generation control (AGC) of conventional thermal generators is capable of absorbing the small changes in voltage on the grid caused by the fluctuation of wind energy (Banakar, Luo, & Ooi, 2008).

The impacts of wind energy on secondary and tertiary reserves vary depending on the specificity of each power system. Some studies find such impacts small. For example, the NYISO study finds only a small increase in the need for secondary/tertiary reserves introduced by wind generation (GE ENERGY, 2005). In contrast, other studies find stronger impacts on secondary/tertiary reserves. Another study shows a range of 2.5-4% of the installed wind power capacity at 10% penetration for a single country (Holttinen, 2004). Strbac found significant increase in the cost of load-following reserves (ILEX Energy; Goran Strbac, 2002). A study on the Irish system found significant impact of large wind penetration on 30-min timescale reserves (Sustainable Energy Ireland, 2004). This thesis will also explore the short-term impacts of wind energy on secondary and tertiary reserves.

Impacts of wind energy on capacity planning

As mentioned earlier, the contribution of each type of technology to the firm capacity and the required margin is essential to the capacity planning in the long term. Because of its variability and uncertainty, wind energy does not contribute to the total firm capacity of a power system the same way conventional generating sources do. At high penetration level, it is less likely for wind energy to contribute to system reliability to the extent it contributes to the average annual energy supply. Therefore, it is important to decide the capacity credit of wind and how much capacity from other generating sources is needed to compensate any reliability contribution unable to be provided by wind energy. This could bring fundamental impact to a power system, particularly if the current generation capacity portfolio is not able to provide such reliability in the presence of a strong wind penetration.

The capacity credit of wind power can be calculated as the amount of conventional generation capacity that can be replaced by wind power capacity, while maintaining existing levels of supply security (EWEA, 2009). In general, the capacity credit of wind tends to decrease as the penetration level of wind increases, and tends to increase as the geographical area of the power system increases (EWEA, 2009).

The capacity credit of wind varies in different systems. Generally speaking, however, wind energy has a positively effect on system adequacy. For example, a German study shows that the capacity credit of wind is between 6% and 8 % in the case of an installed wind power capacity of around 14.5 GW and between 5% and 6 % in the case of an installed wind power capacity of around 36 GW in a future scenario, at a reliability level of 99 % (Dena, 2005). In a Norwegian study, the capacity credit of wind energy is around 31 % at very low wind energy penetration, which is close to its capacity factor. The capacity credit decreases to about 14 % at a 15 % penetration level. This study also found significant smoothing effect from geographical distribution on the wind capacity credit at high penetration (Tande, 2007). Large quantities of wind energy also increase the start-ups and ramping of simple gas turbine, compared with a system with lower wind penetration (ESB National Grid, 2004).

In short, the capacity credit of wind energy is generally lower compared with its capacity factor. In other words, the contribution of wind to the energy production can be much higher than its contribution to the firm capacity, particularly at high penetration level. This is of great relevance to the long term capacity planning, which may require the presence of adequate conventional generating capacities. In addition, because of the impacts on operating reserves, a certain amount of flexible generating capacity is also a need in the generating capacity mix, in order to mitigate the variability and uncertainty of wind.

2.4 Worldwide studies about wind energy

The study on the integration of large quantities of wind energy is a research area of recent interest. During the past decade, a good number of studies have been conducted on the integration of wind energy into the electric power system, as more experience of the integration of wind energy has been accumulated worldwide.

In the United States, NREL has been a leading institute in conducting research on wind energy. Several influential studies have been conducted regarding the development of wind energy and the impacts of integration of wind energy into the power system. Two recent large-scale wind integration studies are the Western Wind and Solar Integration Study (WWSIS) (GE Energy, 2010) and the Eastern Wind Integration and Transmission Study (EWITS) (EnerNex Corporation, 2010), with WWSIS covering most of the Western Interconnection and EWITS covering a large part of the Eastern Interconnection. Both studies analyze different future wind scenarios by running operational models using realistic hourly wind data. The capacity credit of wind and the need for transmission capacity to deliver wind in remote areas are also examined in these two studies. In the WWSIS study, at low wind penetration level, combined-cycled gas turbine (CCGT) is the most affected conventional generating technology. When the wind penetration level increases to 20%, not only CCGT, but also OCGT and coal are further affected. This impact on coal generation becomes even more prominent as wind penetration increases to 30%. In the EWITS study, it is found that the wind capacity credit is significantly sensitive to transmission capacity.

Several important reports have also been published on power systems in European countries. For example, the All Island Grid Study (Department of Communications, Energy and Natural Resources, UK, 2008) compares the costs, CO2 emissions and transmission needs under several future scenarios with different generating capacity portfolios and wind penetration in Ireland. The European Wind Energy Association's recent study, the TradeWind study, was the first to look into the large-scale cross-border wind energy transmission and market design at European level (EWEA, 2009). This study finds that wind energy can be very reliable while providing electricity production.

Another recent study conducted by the European Climate Foundation, Roadmap 2050: a practical guide to a prosperous, low-carbon Europe, explores different approaches to reduce greenhouse gas emissions by at least 80% below 1990 levels by 2050 (The European Climate Foundation, 2010). This study finds that significant amounts of new transmission capacity and backup generation capacity, utilized little, are needed for a reliable future power system where large quantities of wind and solar energy are deployed.

Another influential study by the International Energy Agency (IEA), the IEA Wind Task 25 (also known as the "design and operation of the power systems with large amounts of wind power"), summarizes individual studies on the impacts of wind energy, particularly the impacts of the variability and uncertainty of wind on system reliability and costs. It includes the best practices from Germany, UK, Netherlands, Portugal, Spain, Norway, Sweden and the US. This study does not compare directly between those cases because of different methodologies and assumptions made in each case (IEA, 2007). This study finds that the additional load carrying capability that is provided by wind can be as low as 5% in situations of high wind penetrations and low capacity factor at peak load, or the wind profile is negatively correlated with the load profile, and can be up to 40% in situations of low wind penetration and high capacity factor at peak load.

Most of these studies, however, focus on the operational impact of wind energy in a relatively short period of time by running operation models, with less consideration of the path of capacity expansion that could take place in the power system. In this regard, the report of 20% Wind Energy by 2030, released by the US Department of Energy, is of significance. This study examines some of the costs, challenges and impacts of providing 20% of the electricity generation from wind in the US. In particular, the study uses a power system capacity expansion model, the Regional Energy Deployment System (ReEDS) model (then called "Wind Deployment System model), to create a scenario of a 20% wind penetration and evaluates some of the impacts associated with the deployment of the large amount of wind (DOE, 2008).

Because of the lack of long-term capacity expansion analysis in the existing studies and the opportunity to use the ReEDS model, one part of this thesis analyzes the long-term wind impacts by looking at the trajectories of power system generation capacity. Another part analyzes the short-term impacts by performing a power system operational model. The methodologies and analyses will be presented in Chapters 3 to 6.

CHAPTER 3. RESEARCH APPROACH

3.1 Introduction

Electric power system models can be viewed from the perspective of different time horizons. Basically, these models can be classified into two categories, either operational or planning (Momoh, 2009). In operation scheduling problems, the timeframe of the optimization process is usually up to 24h, or at most a few days, while planning models usually perform in the time frame of years.

Many models have been used in different wind integration studies. For example, the WILMAR model is a tool that models the short term realistic dispatch decisions in a market-based power system that has significant variable resources. This model has been used in several wind studies (Department of Communications, Energy and Natural Resources, UK, 2008) (Holttinen, 2004) (EWEA, 2009). The PROSYM model is another wholesale market simulation model that represents uncertainty through a stochastic scenario tree, as opposed to WILMAR, which represents uncertainty by looking at the demand for spinning reserves (EWEA, 2009).

Among the long-term energy models and in the context of this thesis one can mention the National Energy Modeling System (NEMS), which has been used by the EIA to analyze the impact of a 25-percent renewable electricity standard (EIA, 2009) and other studies. However, because of the intrinsic nature and the macro level, some of these long term energy models have a rather low resolution with overly simplified representations of the characteristics of wind energy and its operation in the power system.

In addition to the two types of computer based models described above, another standard methodology is an analytical approach using the "screening curve" (see (Knight, 1972) (Stoft, 2002)).This method is based on a well-defined optimization approach to minimize the total generation costs, while meeting the loads in each hour. A load duration curve, which represents the cumulative probability distribution over system loads during the year, is the fundamental. It has been deployed to assess the economics of wind energy. For example, this approach was used to assess the long term value of wind and solar in the power system (Lamont, 2008).

In this thesis, a chronological unit commitment and operation model, the Memphis model, will be used for the short-term analysis. A capacity expansion planning model, the ReEDS model, will be used for the long-term analysis. In addition to these two existing computer based models, an ad hoc analytical model has been developed during the realization of the thesis, which describes the theoretical interactions between different technologies in a power system with a significant penetration of wind energy. While the computer-based ReEDS and Memphis models are able to incorporate abundant details to represent the power system more accurately, the analytical model provides theoretical insights to explain the observations obtained by ReEDS and Memphis. In addition, the ReEDS model and the Memphis model are also linked through analysis of the same future year and Memphis will be used as a benchmark to assess the accuracy of ReEDS.

This chapter presents the three models. Some preliminary conclusions on the impact of wind penetration will be provided as well.

3.2 The ReEDS model

The ReEDS model is a GAMS linear programming model that has been developed by the Energy Forecasting and Modeling team of the Strategic Energy Analysis Center (SEAC) at the US National Renewable Energy Laboratory (NREL). It has been and is still undergoing continuous improvement. ReEDS has been used in several influential studies about integration of renewable energy conducted by NREL[1], including the DOE report 20% Wind Energy by 2030: Increasing Wind Energy's Contribution to U.S, as already mentioned in Chapter 2. The version used for the purpose of the thesis is the version released in February 2010. The ReEDS model projects capacity expansions of generation technologies by optimizing the regional electricity generation capacity and transmission capacity, subject to both system internal operation and planning constraints and external policy requirements, such as a carbon policy or a renewable energy policy. Because ReEDS has a strong database of wind resources for the US and explicitly accounts for the variability of wind at a high resolution level, it is chosen for the purpose of this study to investigate the impacts of wind energy on the long run. The timeframe of "long-term" in this context refers to a time span of several decades. To be specific, the model – as it has been used here – considers a period from present to year 2050.

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[1] For a list of publications, see the NREL website (NREL: Regional Energy Deployment System (ReEDS): Related Publications).

ReEDS is able to calculate and build new generation capacity and transmission capacity for each year in the US electric power system, by minimizing system-wide costs of meeting electricity loads, reserve requirements and emission constraints. Besides wind energy, generation technologies considered in this model include conventional technologies, such as nuclear, combined cycle-gas turbines (CCGT), open cycle gas turbines (OCGT), natural gas-steam turbine, coal, hydro, and other renewable energy, such as CSP, solar PV and biomass. The model is also able to represent advanced technologies like CCS and storage. These technologies, however, are not considered in this thesis for the sake of simplification, since the main objective is to illuminate the impacts of wind on conventional technologies. The optimization is performed on a two-year period, totaling 23 loops from 2006 to 2050.

Disaggregation of regions

ReEDS has five levels of spatial disaggregation. These include the 3 interconnections in the US, 13 NERC regions, 32 regional transmission operators and 136 power balancing areas. Moreover, a strong GIS database of 356 wind resource regions has been created specifically for this model, classifying three types of wind resources: onshore wind, shallow offshore wind and deep offshore wind.

Representation of load

In ReEDS, a load duration curve is approximated by disaggregating the time of the year into a set of 17 typical time periods. Summer 10pm-6am, for instance, is one of the time slices. Among these 17 time periods, one super-peak time slice is included that accounts for the average hourly output of the 40 highest hours of demand, to represent the need for enough generating capacity during few but high demand hours. The average output from each type of technology during each of these time slices is then calculated through the optimization process. For wind energy, a capacity factor for each time slice is determined as well. This approach of approximating the load during curve is also used by EIA in the NEMS model (DOE/EIA, 2001).

Representation of the characteristics of wind

Three basic resource variability parameters for wind are calculated in ReEDS for each time period before the linear program optimization is conducted for that period. These parameters include capacity credit of wind, operating reserves needed due to wind variability and uncertainty, and wind surplus. For each of these parameters, a marginal value is calculated, which applies to new installations of wind in that period, and an "old" value is calculated, which applies to all the capacity built in previous periods. Statistical methods are used to calculate these values. An expected value and standard deviation are calculated for loads, conventional generator availabilities and wind. The capacity credit is a function of the amount and type of wind consumed in the region, the dispersion of the wind resources, the electric load, the variability of the load and the amount and reliability of conventional capacity contributing to the load in that region. Operating reserves include spinning reserve and quick-start capability. The total operating reserves are calculated separately for contingency, demand variability and wind forecast errors. Wind forecast errors are assumed to be the wind output delta of each considered hour and the preceding hour.

Objective function and major decision variables

The objective function in the ReEDS linear program is the minimization of the total costs of the considered electric power system, so the model has to decide which types of technologies have to be added to the system in each time period. Major variables are the new installed capacities and the generation of each technology for each time period in each region, the reinforcements of the transmission capacity for conventional generation, wind and solar, and the amount of spinning reserve and quick start capacity. The total cost includes the following components:

- The present value of capacity investments in generation and transmission;
- The present value of the costs for energy production over the next 20 years to meet electricity demand, including fuel costs, fixed and variable operation costs;
- The cost of providing operating reserves.

Major constraints

The objective function is subject to different types of constraints, the major ones including the following:

- Resource constraints: the total wind and solar capacity cannot exceed the potential resource availability in each region.
- Demand constraint: the electric load in each balancing area must be met in each time period throughout the year;
- Firm capacity margin and operating reserve constraints: in each region and period, enough capacity must be present to meet the firm capacity margin requirement and operating reserve requirements;
- Wind surplus constraint: wind output needs to be curtailed if wind output plus must–run conventional output exceeds the demand;
- Emission constraints: emissions of SO2, NOx, mercury, and CO2 cannot exceed a prescribed limit.

Data source

The ReEDS model requires a comprehensive set of input data representing technical specifications of each technology, the power system, and relevant policies. The input data used for this thesis in ReEDS come from two sources: projections of the EPPA model (see Chapter 4 for more introductions about EPPA) and the original input data set used by SEAC at NREL, which has been provided by both the EIA and Black & Veatch (W. Short, N. Blair, P. Sullivan, T. Mai, 2009).

3.3 The Memphis model

Developed by the Institute for Technological Research at Comillas University for the Spanish Electricity Transmission System Operator (Red Eléctrica de España), the Memphis model is also a GAMS linear optimization model that simulates the hourly operation of a power system by optimizing the total cost. It has been used by the Institute to analyze the Spanish power system in a scenario for the year 2016, which corresponds to the last year of the electricity and gas planning period 2008-2016 that was planned by the Ministry of Industry of Spain. Unlike ReEDS, the Memphis model does not allow the construction of new installed capacity into the system being considered. However, the model simulates the electric power system unit commitment and operation following chronology. Very importantly, it simulates the process of day-ahead wind forecasts at different time points and the correction of wind forecast error, capturing the details of the use of spinning reserves and quick start reserves. Therefore, it is used for the short-term analysis of the impacts of wind in this thesis. Some major aspects of the formulation of the Memphis model are described below. For a detailed description of the model, see the Memphis User Guide (Instituto de Investigación Tecnológica, 2009).

Objective function and decision variables

The objective function of Memphis is the minimization of the total operating cost of the system. The model is typically run for one year, but the horizon of the optimization process is the day-ahead market, equivalent to the classical unit-commitment process under centralized operation planning. The total cost to be minimized includes several components:

- The fixed operational and maintenance (O&M) costs, variable O&M costs and startup costs of operating thermal units;
- The cost of using hydro units for emergency and the variable O&M costs for operating hydro units;
- Costs of non-served energy;
- Costs of failing to provide up and down operating reserves.

Major constraints

The objective function is subject to several constraints, the major ones including:

- Demand constraint: productions from thermal and hydro units minus charging of pumped hydro should equal demand minus wind, distributed generation, non-served energy and wind surplus. Wind and distributed generation are always dispatched first unless there is a conflict between wind output and the technical minimum of thermal units, in which case wind surplus will appear.
- Operating reserve constraint: For up reserves, the sum of the difference between the maximum capacity and the actual production above its technical minimum of a thermal unit, a percentage of the difference between the maximum capacity and the sum of the actual production and production for emergency of a hydro unit, the potential generation from pumped hydro, and the possible failure of up reserves, has

to be larger than the operating reserve requirement for ramping up. For down reserves, the total of the production of thermal units, the difference between production and minimum production of hydro units, the potential of pumped hydro, and the possible failure of down reserves, needs to be larger than the operating reserve requirement for ramping down.

- Other constraints include the technical minimum constraint, pumped hydro constraint, the constraint on the start-ups and shut-downs of thermal units, the constraint on the minimum time required for a unit to start up or shut down, the constraint on the balance of reservoirs, and constraints on different types of hydro units. The details of these constraints are not presented here as they are not in the center of discussion in the thesis.

Subject to these constraints, the program calculates the value of the decision variables, which include the start-ups and shut-downs of units at each time, the production of each generating unit in each hour, the units to provide operating reserves, etc.

Optimization process

The optimization process of Memphis is divided into two phases. The first phase is the unit commitment phase that takes into account the stochasticity of wind forecast errors at the wind production level, the availability of the generating units and other parameters, before the considered day. The second phase is the simulation phase for the real time dispatch of generation. The deviations of the prediction are corrected during real time.

Representation of demand and wind

The Memphis model uses the chronological hourly data of demand, historical hourly output of wind and corresponding wind forecast error for each hour. Wind forecast data are considered at two time points: 2 pm of the day before and 12 am at the start of the day considered for dispatch. As the lead time is shorter, at 12 am, better wind forecast data is available and thus some of the prediction deviation can be corrected via units that are able to be connected online at real time.

Data for Memphis

Major inputs required for the Memphis model include the following:

- The installed capacities of conventional generation technologies;
- The hourly output profile of wind and corresponding day-ahead forecasts at 2pm the day before and 12am the start of the same day, the hourly output data of distributed generation, in this case solar PV, and the hourly load profile;
- The basic performance parameters of each generating unit, including outage rates, maximum output capacity, minimum output capacity, heat rates and fuel prices.

For the ERCOT case, the installed capacity mix is taken from the projected results of the long term analysis obtained by ReEDS. The same parameters for the technologies used in ReEDS are used in Memphis as well. For the base case, the wind hourly output and corresponding forecast series are scaled from sample data for ERCOT to ensure that the total annual productions of wind and solar PV are consistent with the ReEDS projections for the analyzed year. For the Spanish case, the same input data are used as provided by the Memphis developers for their study for year 2016.

3.4 The analytical model

3.4.1 Introduction

An analytical model has been developed to describe the theoretical interactions between the diversity of technologies in a power system, when subject to some basic technical, economic and environmental constraints. The "screening curve" method, as briefly mentioned in Section 3.1, has been used to determine the optimal capacities of base load, intermediate and peaking technologies to meet the demand that is represented by its load duration curve for a given future year. The technologies are simply described by their capital (fixed) and variable costs. The fixed cost includes capital investment and O&M fixed cost, expressed on a yearly basis in the unit of [cost/power (e.g MW)/year]. The variable cost includes the fuel cost and variable O&M cost, expressed in [cost/energy (e.g MWh)]. This is a "static" capacity expansion model, since it only tries to determine the optimal generation mix for a future year, therefore ignoring the trajectory that is needed to reach that situation from the present existing capacity. The model also computes the optimal utilization factor of each selected technology and it offers an intuitive geometrical interpretation of the optimal solution. The original screening curve method is not able to incorporate realistic features of power plants such as existing plant capacities, technical minima, hydro storage reservoir capacity or pumping storage technologies. It is possible to add these features to the model, at the cost of losing the intuitive geometrical interpretation and the closed form analytical solution to the optimal technology mix problem, see (Ramos, Pérez-Arriaga, & Bogas, 1989).

Here the screening curve method is extended to include a significant penetration of wind generation and a few constraints that typically accompany the analysis of the development of this renewable and intermittent technology: maintaining the overall system reliability, some CO2 emissions target for the power system and some mechanism of promotion to make wind competitive with other less carbon-friendly technologies. Wind is mostly treated the same as any other technology, with a fixed cost and zero variable cost. The resulting model is still simple enough so that a closed form analytical solution can still be obtained, while also maintaining a simple geometrical interpretation.

Compared to conventional thermal plants – coal, oil, gas or nuclear, a characteristic feature of wind technology is that the average production that can be sustained permanently over a period of a year, which in conventional thermal plants is the average availability, only slightly depends on the technical availability of the wind generators. Rather, it mostly depends on the average availability of the wind resource, which is much lower, rarely exceeding 40% and typically in the 30% range or lower. Here it will be assumed that the estimated average availability of wind is constant throughout the considered year. Similarly, the readiness of wind to operate when required – typically at times of high demand or in emergencies, a reliability trait that is termed here as the firm capacity or capacity credit, as introduced in Chapter 2 is much lower than the average availability, because of the intermittent nature of the wind resource. In conventional plants the firm capacity is somewhat higher than the average availability, since the plant owners usually have economic incentives to have the plants in good operating order when demand is high or emergency conditions are expected.

The model has been developed under two different regulatory frameworks: centralized planning with cost-of-service remuneration of generation and a market-based scheme. The optimality conditions derived for each case provide interesting information about the costs associated with the different regulatory measures and insights into the mechanisms that are required in a market to drive investment towards the socially optimal mix that would happen in a central planned system. This model can be seen as an extension of (Perez-Arriaga & Meseguer, 1997), with a less detailed formulation but with the incorporation of intermittent technologies and new environmental constraints.

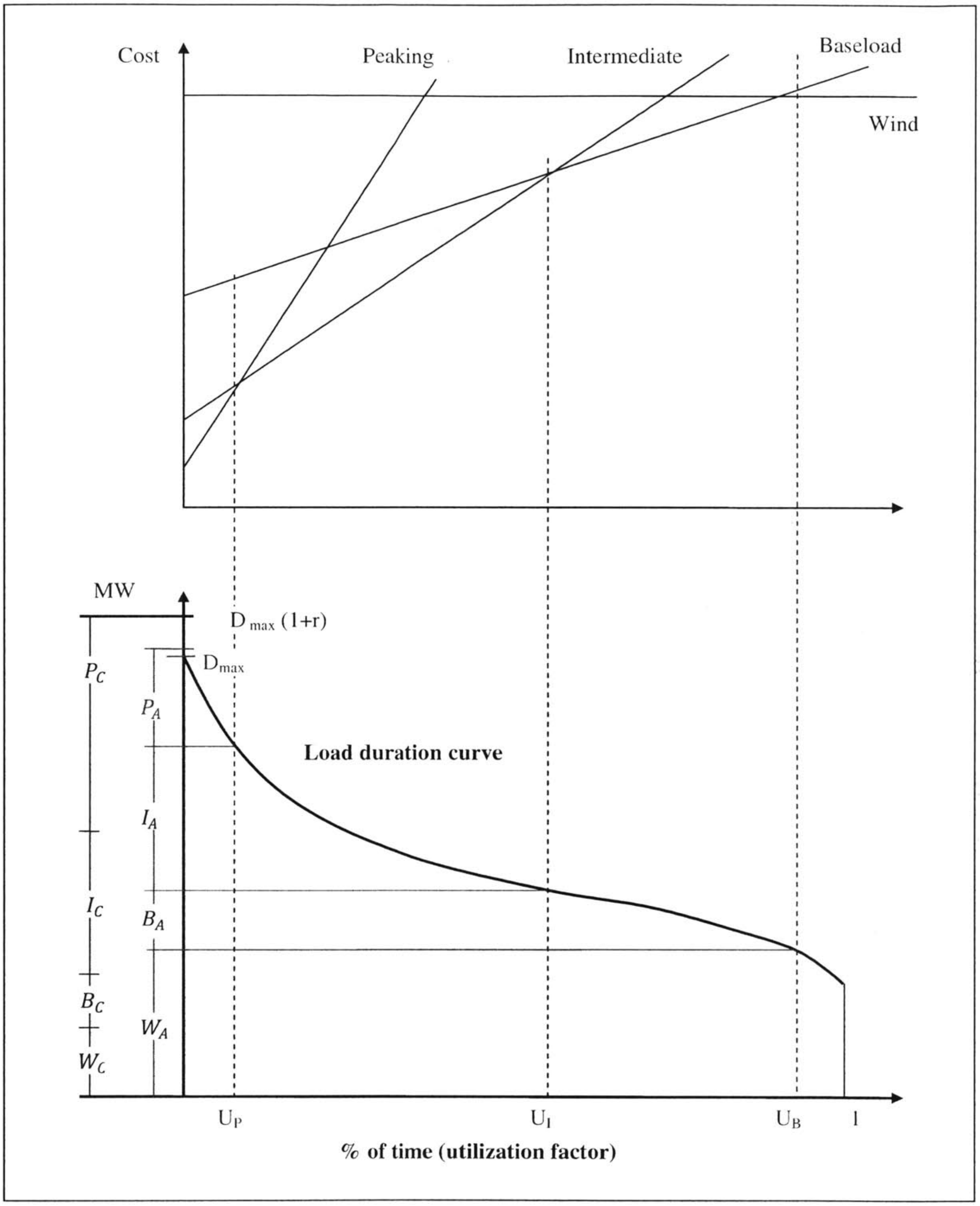


Figure 3-1 Analytical Model

3.4.2 Basic variables and parameters

For the sake of simplicity, only four generic technologies are considered in the model: a peaking technology P, such as an open cycle gas turbine, an intermediate technology I, like a combined cycle gas plant, a base load technology B, such as coal or nuclear and the wind technology W. The key variables and parameters are defined as follows:

- $D(u)$ is the demand D as a function of the per unit time u that each value of demand is exceeded, which is the expression of the load duration curve. It can alternatively be interpreted as the generation plants utilization factor u for each level of demand D. In Figure 3-1 each technology has a utilization factor, U_P, U_I, and U_B, and wind is assumed to be base loaded with a utilization factor of 1;
- P_T, I_T, B_T, W_T are the installed capacities (MW) of each technology;
- P_A, I_A, B_A, W_A are the average availabilities of each technology. The availability factors are denoted by a_P, a_I, a_B, a_W. It should be noted that, as indicated above, the average availability of conventional technologies is different from that of wind in this model. For wind, the average availability is considered equal to its annual capacity factor (assuming no curtailments), which basically depends on the availability of the resource, rather than the wind turbine availability. The estimated average annual availabilities for the considered technologies are $P_A = a_P P_T$, $I_A = a_I I_T$, $B_A = a_B B_T$, $W_A = a_W W_T$;
- c_P, c_I, c_B, c_W are the per unit capacity credits of each technology. Thus the contributions of each technology to the power system reliability are $P_C = c_P P_T$,

$I_C = c_I I_T$, $B_C = c_B B_T$, $W_C = c_W W_T$, which is equivalent to $P_C = P_A \frac{c_P}{a_P}$, $I_C = I_A \frac{c_I}{a_I}, B_C = B_A \frac{c_B}{a_B}, W_C = W_A \frac{c_W}{a_W}$;

- r is the system firm capacity margin requirement in per unit of the peak demand level;
- e_P, e_B, e_I are the emission rates of technologies P, B and I, respectively (note that the carbon emission rate of wind is 0);
- F_P, F_I, F_B, and F_W are the annual levelized fixed costs per unit of installed capacity of each technology, while V_P, V_I, V_B, and V_W are the corresponding variable costs, with $V_W = 0$;
- And E_p, E_I, E_B, and $E_W$are the total annual energy production from each technology.

Once the installed capacities for each technology are known, the available and firm capacities are also known immediately and, from simple inspection of the lower part of Figure 3-1, where the technologies have been ordered in terms of variable costs as it is usual in the economic dispatch of generation plants, the corresponding annual productions are also known. Therefore the only unknowns in the technology mix are, in principle, the values of the installed capacities.

3.4.3 Analysis for the central planning condition

Under centralized planning, which is typically accompanied by cost-of-service remuneration of the generation activity, the objective is to minimize the total system cost

Z to be paid by consumers, which is the sum of the total fixed and variable costs of each generation technology that are needed to meet the demand over the considered year:

Minimize: $Z = (F_P P_T + F_I I_T + F_B B_T + F_W W_T) + (V_P E_P + V_I E_I + V_B E_B)$ (1)

where the energies that are produced by each technology, for any given values of the installed capacities, can be defined from simple inspection of Figure 3-1 as previously indicated:

$$E_P = \int_0^{U_P} D(u)du - U_P(I_A + B_A + W_A),$$

$$E_I = \int_{U_P}^{U_I} D(u)du - (U_I - U_P)(B_A + W_A) + U_P I_A,$$

$$E_B = \int_{U_I}^{U_B} D(u)du - (U_B - U_I)W_A + U_I B_A,$$

$$E_W = \int_{U_B}^{1} D(u)du + U_B W_A$$

So far this is just the classic screening curves model, with a specific characterization for the average availability of wind. This thesis further analyzes the impact when this classic model has three additional constraints. In the first place the system planner will have to specify the level of reliability that the system has to meet during the considered future year and here the separation between "installed" and "firm" capacities will be made explicit. Also, because of environmental or energy dependence concerns, policymakers may impose additional constraints. Some power systems may be subject to limits in the total volume of CO2 emissions during the considered year. A minimum target of production with some renewable technology such as wind may be required by a certain deadline as an alternative measure to reduce carbon emission, to promote energy security or perhaps to comply with some internationally agreed commitments, etc. These three constraints are expressed mathematically as follows:

- Firm capacity margin constraint:

$$P_C + I_C + B_C + W_C \geq D_{max}(1 + r) \quad (2)$$

- Carbon emission constraint:

$$\mathrm{E_p e_p + E_I e_I + E_B e_B \leq e_{max}} \quad (3)$$

- Minimum wind production constraint (an energy policy constraint):

$$W_A \geq \mathrm{W_{Amin}} \quad (4)$$

Where W_A has been used instead of E_A to make more explicit the independent variables to be determined in the optimization process.

A graphical representation of the screening curves solution that slightly differs from the classical one, because of the special features of wind regarding average availability and firm capacity, is presented in Figure 3-1.

Optimization process

The Lagrange multiplier method is used to optimize the total cost function under the three constraints, see (Bradley, Hax, & Magnanti, 1977) for details. $\lambda_1, \lambda_2, and\, \lambda_3$ are introduced here as the Lagrange multipliers (all of them positive) corresponding to the three constraints in this model. Thus the Lagrange function is

$$\Lambda(P_T, I_T, B_T, W_T, \lambda) = Z - \lambda_1[P_C + I_C + B_C + W_C - D_{max}(1+r)] + \lambda_2(E_P e_P + E_I e_I + EBeB - Emax - \lambda 3\, WA - \mathrm{WAmin} \quad (5)$$

The optimality conditions result from equating to zero the first order derivatives of the Lagrangian function with respect to the four independent variables and the three multipliers (which just result in the three original constraints):

$$\frac{\partial \Lambda}{\partial P_T} = F_P - \lambda_1 c_P = 0 \quad (6)$$

$$\frac{\partial \Lambda}{\partial I_T} = F_I - a_I U_P(V_P - V_I) - \lambda_1 c_I - \lambda_2 a_I U_P(e_P - e_I) = 0 \quad (7)$$

$$\frac{\partial \Lambda}{\partial B_T} = F_B + a_B[-U_P V_P - (U_I - U_P)V_I + U_I V_B] - \lambda_1 c_B + \lambda_2 a_B[-U_P e_P - (U_I - U_P)e_I + UIeB = 0 \quad (8)$$

$$\frac{\partial \Lambda}{\partial W_T} = F_W - a_W[U_P V_P + (U_I - U_P)V_I + (U_B - U_I)V_B] - \lambda_1 c_W + \lambda_2 a_W[-U_P e_P - UI - UPeI - (UB - UI)eB - aW\lambda 3 = 0 \quad (9)$$

Rearranging Eq. (6) – Eq. (9), four optimality conditions can be obtained:

$$\lambda_1 = \frac{F_P}{c_P} \quad (10)$$

$$\frac{F_P}{a_P} + (V_P + \lambda_2 e_P)U_P = \frac{F_I}{a_I} + \frac{F_P}{c_P}\left(\frac{c_P}{a_P} - \frac{c_I}{a_I}\right) + (V_I + \lambda_2 e_I)U_P \tag{11}$$

$$\frac{F_I}{a_I} + \frac{F_P}{c_P}\left(\frac{c_P}{a_P} - \frac{c_I}{a_I}\right) + (V_I + \lambda_2 e_I)U_I = \frac{F_B}{a_B} + \frac{F_P}{c_P}\left(\frac{c_P}{a_P} - \frac{c_B}{a_B}\right) + (V_B + \lambda_2 e_B)\, U_I \tag{12}$$

$$\frac{F_B}{a_B} + \frac{F_P}{c_P}\left(\frac{c_P}{a_P} - \frac{c_B}{a_B}\right) + (V_B + \lambda_2 e_B)U_B = \frac{F_W}{a_W} + \frac{F_P}{c_P}\left(\frac{c_P}{a_P} - \frac{c_W}{a_W}\right) - \lambda_3 \tag{13}$$

These four optimality conditions, as shown in Eq. (10) – Eq. (13), together with the three constraints in Eq. (2) – Eq. (4), determine the optimal values of the capacities of the four considered technologies, as well as the corresponding annual production levels and the utilization factors. The first information that can be extracted from the inspection of Eq. (11), (12) and (13) is that they maintain the same structure that is characteristic of the screening curves approach and that allows the geometrical interpretation of the competition among pairs of technologies that is depicted in the upper part of Figure 3-1:

Fixed cost of technology 1 + Variable cost of technology 1 x Breakeven utilization factor between technologies 1 & 2 = Fixed cost of technology 2 + Variable cost of technology 2 x Breakeven utilization factor between technologies 1 & 2, where now the original fixed and variable costs have to be extended to account for the presence of the three constraints – represented by the three Lagrange multipliers, explained below – and the differences between the values of installed, available and firm capacities – represented by the corresponding coefficients.

A byproduct of the optimization process is the determination of the Lagrange multipliers, also called dual variables, of the three constraints, with an interesting economic interpretation.

λ_1 is the increment in the total supply cost if one more unit of firm capacity is required to further increase system reliability. As shown in Eq. (10), λ_1 equals the fixed cost of the amount of installed peaking technology P that is needed to meet an additional request of one more MW of firm capacity. The more reliable the peaking technology P is, the less cost this constraint imposes to the system. The value of λ_1 solely depends of the technology with the lowest cost per MW of firm capacity, since this is the least costly option to meet additional reliability margins.

λ_2 is the increment in the total supply cost if the carbon emission cap is reduced by one unit. The carbon emission cap implicitly adds an extra cost to the total variable cost of producing energy for each technology, thus changing the breakeven point of the utilization factor between any two technologies with different carbon emission rates e.

λ_3 is the increment in the total supply cost if the requested minimum energy production from wind is increased by one unit. λ_3 only appears in Eq. (13), since it has been assumed that wind production happens at all times and, since its variable cost is zero, it should occupy the lowest level while filling the load duration curve.

The optimality conditions will be examined now in more retail. In order to facilitate this task, a simplified version of the model will be examined first, where only the reliability constraint is considered. Gradually the other two constraints will be also included.

Simplification case 1: No renewable energy policy or carbon emission cap

Without any carbon emission constraint or renewable promotion policies, $\lambda_2 = 0$, $\lambda_3 = 0$, only the reliability constraint is left and the optimality conditions (11), (12) and (13) become:

$$\frac{F_P}{a_P} + V_P U_P = \frac{F_I}{a_I} + \frac{F_P}{c_P}\left(\frac{c_P}{a_P} - \frac{c_I}{a_I}\right) + V_I U_P \tag{14}$$

$$\frac{F_I}{a_I} + \frac{F_P}{c_P}\left(\frac{c_P}{a_P} - \frac{c_I}{a_I}\right) + V_I U_I = \frac{F_B}{a_B} + \frac{F_P}{c_P}\left(\frac{c_P}{a_P} - \frac{c_B}{a_B}\right) + V_B U_I \tag{15}$$

$$\frac{F_B}{a_B} + \frac{F_P}{c_P}\left(\frac{c_P}{a_P} - \frac{c_B}{a_B}\right) + V_B U_B = \frac{F_W}{a_W} + \frac{F_P}{c_P}\left(\frac{c_P}{a_P} - \frac{c_W}{a_W}\right) \tag{16}$$

These three equations represent the trade-offs in the utilization of the four considered technologies for the simple case where only the reliability constraint is active. Note how the larger the average availability factor "a" of a technology is, the more competitive the technology is, since the fixed cost component becomes smaller. The only change here with respect to the classic screening curves model is that the fixed cost of every technology, including wind, has now an extra term, which accounts for the extra cost of firm peaking capacity $\frac{F_P}{c_P}$ if the ratio $\frac{c}{a}$ for the considered technology differs from the ratio $\frac{a}{c}$ for the peaking technology. This term is a bonus or a penalty added to the cost of one MW of average available capacity of the considered technology, depending on the relative values of the two ratios. It is expected that conventional technologies will have similar c/a ratios, with "c" being slightly larger than "a" since the owners of the plants should make a special effort to be available at times of stress for the system. Therefore the extra term is expected to have little significance. The situation is very different for wind, since its firm contribution c_W per MW of installed capacity will be in general much smaller than the average annual production a_W of that 1 MW. This means that the fixed cost of wind in equation (16) will be heavily penalized with an additional component that consists of a factor times the fixed cost of firm peaking capacity. This is a precise mathematical expression for the popular assertion that "wind generation needs to be backed up by peaking generation". As can be seen here, all technologies, depending of their readiness in case of emergency compared to the peaking technology, are penalized or credited because of this effect, which is magnified in case of an intermittent technology like wind.

This makes clear the conditions for wind to be competitive in the absence of any specific promotion mechanism, since, if the value of U_B in equation (16) happens to be larger than 1, wind generation will be too expensive to be used as a base load technology and technology B will be used instead, displacing wind completely. From equation (16) it can be appreciated that, despite having a zero variable cost, the fixed cost of 1 MW of installed wind capacity is doubly penalized: first because its average annual availability factor a_W will be much smaller than the corresponding factor a_B for the conventional base load technology B; and second, because of the extra term in the extended fixed cost of wind due to its small firm capacity factor c_W compared to the B technology. On the other hand, if wind happens to be preferable to the conventional base load technology B, it will occupy the lowest band when filling the load duration curve, with the only limitation on the volume and quality of the existing wind resources that will result in a progressive degradation of the wind parameters a_W and c_W. It may even happen that wind completely displaces technology B, so that the breakeven utilization factor happens between wind and the intermediate technology I. In summary, wind in combination with peaking units may successfully compete against base load generation, if the economics are right.

As already shown in the literature review in Chapter 2, the capacity credit, c_W, has been observed to vary significantly under different circumstances. However, in general, for large wind penetrations a_W and c_W differ widely and many studies show that the relative capacity credit of wind decreases as the wind penetration increases, because the wind resource is typically strongly correlated across a region, see (NERC, 2009) or (IEA, 2007). When there is sufficient inter-area transmission capacity within a large geographic area the capacity credit of wind will improve (NERC, 2009).

In the two cases that follow, for the sake of further simplifying the mathematical expressions, it will be assumed that the available and firm capacities are the same for the three conventional technologies P, I and B, and therefore $a_P = c_P, a_I = c_I,$ and $a_B = c_B$. It has been already discussed under which conditions this is a reasonable simplification. The reliability constraint will be assumed to be active in both cases.

Simplification case 2: CO2 emission cap plus reliability constraint, but no active renewable energy policy

In this case, besides the reliability constraint, the carbon emission constraint will be active, while there is no minimum requirement for wind production or perhaps the carbon constraint is able by itself to achieve any prescribed wind penetration target. Therefore $\lambda_2 \neq 0$ and $\lambda_3 = 0$, and the optimality conditions (11), (12) and (13) become:

$$\frac{F_P}{a_P} + (V_P + \lambda_2 e_P)U_P = \frac{F_I}{a_I} + (V_I + \lambda_2 e_I)U_P \qquad (17)$$

$$\frac{F_I}{a_I} + (V_I + \lambda_2 e_I)U_I = \frac{F_B}{a_B} + (V_B + \lambda_2 e_B)\, U_I \qquad (18)$$

$$\frac{F_B}{a_B} + (V_B + \lambda_2 e_B)U_B = \frac{F_W}{a_W} + \frac{F_P}{c_P}\left(1 - \frac{c_W}{a_W}\right) \qquad (19)$$

As can be observed from the preceding equations, the impact of the carbon constraint is to increase the effective variable cost of any conventional technology with CO2 emissions by an additional term that depends on the emission rate of the considered technology and the dual variable of the emissions constraint. The presence in the optimal technology mix of technologies with very low or even without CO2 emissions, as it is here the case of wind, is favored by this policy.

Simplification case 3: Renewable energy policy plus reliability constraint, but no CO2 emission limit

In this case, a minimum target level of penetration of wind production is mandated, while the CO2 emissions constraint either does not exist or is inactive because the optimal technology mix with the mandated minimum level of wind production already meets any required emissions limit. The reliability constraint is also assumed to be active. Therefore $\lambda_2 = 0$ and $\lambda_3 \neq 0$, and the optimality conditions (11), (12) and (13) become:

$$\frac{F_P}{a_P} + V_P U_P = \frac{F_I}{a_I} + V_I U_P \quad (20)$$

$$\frac{F_I}{a_I} + V_I U_I = \frac{F_B}{a_B} + V_B U_I \quad (21)$$

$$\frac{F_B}{a_B} + V_B U_B = \frac{F_W}{a_W} + \frac{F_P}{a_P}\left(1 - \frac{c_W}{a_W}\right) - \lambda_3 \quad (22)$$

It can be observed that the only impact of the wind production target constraint is to reduce the effective fixed cost of wind in an amount per installed MW equal to the dual variable of the constraint, therefore forcing wind to be preferred to the base load technology B until the desired target is met. The breakeven utilization factors between any technologies other than wind are not affected. Note that the set of equations in this case is different from the equations in case 2, and therefore the corresponding solution for the optimal technology mix will also be different in both cases. Of course, both regulatory measures are not designed to meet exactly the same objectives and this is why their impacts are different. If the objective is just to reduce emissions then the model in case 2 is more efficient. Conversely, if the final objective is to achieve a certain level of wind penetration – for whatever reason – then the model in case 3 will be more efficient to achieve that goal.

3.4.4 Optimal generation expansion in a market-based regulatory framework

In a market-based environment, each agent – whether existing generators, potential investors or consumers – tries to maximize its net profit: for generators, this is the margin of the income from selling the electricity output over the total production costs. For consumers it is the margin of the utility obtained from electricity utilization minus the purchase costs. The price of electricity transactions is determined by market conditions.

The regulatory authorities may want that the same policy goals that were established under centralized planning – regarding reliability, emissions and wind production levels – could also be achieved under market conditions. However, market forces by themselves will not yield these results. If these objectives are to be attained by the market agents, it will be necessary that regulators provide these agents with the right incentives.

For this purpose, in this model a capacity payment τ (in \$/MW of firm capacity) is established to encourage sufficient investment to secure the system reliability target; a carbon emission charge σ (in \$/ton of CO2 emitted) penalizes CO2 emissions; and a subsidy s (in \$/MW of average wind availability W_A[2]) promotes wind generation deployment. In the market the technologies will fill the load duration curve in the same merit order as in Figure 3-1 and, if having the right value, rational investors will install sufficient generation so that all demand will be served, as it happened under central planning. Generators will have to include in their market bidding price, in addition to

[2] Note that, given the definition of "average availability" that has been adopted for wind, the subsidy s is actually equivalent to a feed-in tariff (or a production tax credit) that is applied to production (MWh) rather than to installed capacity (MW).

their variable cost, an additional component equal to being multiplied by the corresponding emission rate.

The profit for the generators of each one of the technologies can be calculated as follows:

$$\Pi_P = (V_P + \sigma e_P)E_P + \tau P_C - F_P P_T - V_P E_P - \sigma E_P e_P = \tau P_C - F_P P_T = (\tau c_P - F_P)P_T \quad (23)$$

$$\Pi_I = (V_P + \sigma e_P) \times I_A U_P + (V_I + \sigma e_I) \times \left[\int_{U_P}^{U_I} D(u)du - (U_I - U_P)(B_A + W_A)\right] + \tau I_C - F_I I_T - V_I E_I - \sigma E_I e_I = \tau I_C + U_P I_A(V_P + \sigma e_P - V_I - \sigma e_I) - F_I I_T \quad (24)$$

$\Pi_B =$

$(V_P + \sigma e_P) \times B_A U_P + (V_I + \sigma e_I) \times [B_A(U_I - U_P)] + (V_B + \sigma e_B) \times \left[\int_{U_I}^{U_B} D(u)du -\right.$

$(UB-UI) WA+\tau BC-FBBT-VBEB-\sigma EBeB=\tau BC+UPBAVP+\sigma eP-VI-\sigma eI+BAUIVI$

$+\sigma eI-VB-\sigma eB-FBBT$ (25)

$$\Pi_W = (V_P + \sigma e_P)U_P W_A + (V_I + \sigma e_I)(U_I - U_P)W_A + (V_B + \sigma e_B)(U_B - U_I)W_A + \tau W_C + sW_A - F_W W_T = \tau W_C + U_P W_A(V_P + \sigma e_P - V_I - \sigma e_I) + U_I W_A(V_I + \sigma e_I - V_B - \sigma e_B) + U_B W_A(V_B + \sigma e_B) + sW_A - F_W W_T \quad (26)$$

Under perfect competitive market conditions there will be multiple owners of generation assets for each type of technology. Assuming the investors act with economic rationality, they will continue installing new capacity until their profit margins, as computed in the equations above, become zero. These are the new optimality conditions for the technology mix in a market environment:

$\Pi_P = 0$, which is equivalent to $\tau c_P - F_P = 0$ (27)

$\Pi_I = 0$, which is equivalent to $\tau c_I + U_P a_I(V_P + \sigma e_P - V_I - \sigma e_I) - F_I = 0$ (28)

$\Pi_B = 0$, which is equivalent to $\tau c_B + U_P a_B(V_P + \sigma e_P - V_I - \sigma e_I) + a_B U_I(V_I +$

$\sigma e_I - V_B - \sigma e_B) - F_B = 0$ (29)

$\Pi_W = 0$, which is equivalent to $\tau c_W + U_P a_W(V_P + \sigma e_P - V_I - \sigma e_I) + U_I a_W(V_I + \sigma eI - VB - \sigma eB + UBaW(VB + \sigma eB) + \mathrm{s}aW - FW = 0$ (30)

When the optimality conditions (27) to (30) for a market-based regulation are compared to the set of optimality conditions under centralized planning, equations (10) to (13) plus the three constraint equations (2) to (4), it can be easily verified by observation that both sets result in exactly the same values for the installed capacities P_T, I_T, B_T and W_T if the economic incentives under market conditions take the values:

$\tau = \lambda_1$ (31)

$\sigma = \lambda_2$ (32)

$s = \lambda_3$ (33)

From a market perspective, the interpretations of the values of τ, σ and s have a new light. If the regulator wants more reliability than the level that the market provides by itself, he may offer an additional remuneration per MW of installed firm capacity, which amounts to the complete fixed cost F_P per MW of installed peaking capacity. This complete payment τ is needed, since this extra peaking capacity will not make any additional money selling electricity in the market. Obviously this would attract an infinite volume of new investment in peak capacity and the regulator should establish a quota – equal to the desired reliability margin – beyond which no further capacity payment would be awarded.

The carbon charge σ increases the competitiveness of low carbon emission technologies, both in the operation of the power system with any existing capacity and for the investors in new capacity. An adequate value of σ, as given by equation (32), will result in a reduction of CO2 emissions down to any required target.

The subsidy for wind s is equivalent to a negative variable cost of wind energy[3]. To reach the same level of penetration as in the central planned power situation, the subsidy is set to a value such that the profit from production at the demand level by the incremental capacity is zero, which equals λ_3 .

3.4.5 Conclusions from the analytical model

Some interesting regulatory conclusions may be drawn from this analytic model.

The classic screening curves model for static generation expansion can be extended to include renewable intermittent technologies, such as wind or solar, and some important policy measures regarding power system reliability, carbon emissions or minimum renewable penetration. Meaningful analytical results in closed form and also indicative numerical values can be obtained from the extended screening curves model. The impact of the three policy measures can be clearly identified in the typical screening curves optimality conditions, as additional terms that modify either the fixed cost or the variable cost of the different technologies, providing insights about the role played and the implications of these technologies on the optimal generation technology mix and the

[3] Again, note that s and target at different concepts. s is a subsidy to wind production, while the is a subsidy to the installed capacity of wind, equivalent to a reduction of the fixed cost of wind capacity.

utilization of each type of fuel. The convenience of using these simple analytical models should be stressed at a time when it has become clear that energy policy measures will dominate for a long time the investment and operation decisions of the future power systems.

Regardless of whether the regulatory framework is market-oriented or centrally planned, several technologies of very different characteristics will integrate the optimal technology mix, due to the multiple levels of demand during the considered time period of one year. The model shows the regulatory measures that have to be applied so that a power system under market-based conditions results in the same optimal mix and plant operation than a centrally planned system under reliability, emissions and renewable penetration requirements.

A capacity payment per unit of firm installed capacity will incentivize rational investors to install new capacity so that any desired reliability level can be reached.

A penalty on CO2 emissions will make rational market players and investors to behave so that system operation and investment mimics the results obtained under central planning and a CO2 price that is equal to the penalty.

Any desired level of wind penetration can be achieved in a market environment by subsidizing every MWh of wind production with an adequate monetary value.

The dual variables of the energy policy constraints in the screening curves model under centralized planning provide interesting information, both quantitative and qualitative, on the technical and economic impact of these constraints, both on total system costs and on the relative competitiveness of the different technologies.

The cost of one additional MW of reliability margin is equal to the fixed cost of one MW of firm capacity that is provided by the technology whose characteristics - according to the screening curves model – make it suitable to play the peaking role[4].

A reduction of one more ton of CO2 annual emissions implies a burden of an extra component in the variable cost of any technology with CO2 emissions, depending also on the value of the corresponding emission coefficient.

One more MWh of required wind production can be translated into a fictitious reduction in the fixed cost of new wind generators so that they become more competitive with the baseload technology against which wind competes for a niche under the load duration curve.

The model allows the comparison of cost effectiveness of policy measures when trying to achieve emission reduction and/or renewable penetration goals.

[4] The amount of subsidy can be reduced in reality if the model would have taken into consideration the income that peaking units could obtain from the market as remuneration for provision of operating reserves or when market prices equal the cost of non-served energy in case of generation shortages (not included in the model).

Among the characteristics that are influential in determining the optimal technology mix, the impact of the differences between installed capacity, average available capacity and firm capacity for each considered technology has been highlighted here. This is particularly important when a strong presence of intermittent technologies – such as wind or solar – is expected, since for these technologies the difference between firm and average available capacity is typically large. In this model, it has been assumed that, as it is frequently the case, the regulatory authorities require a minimum level of reliability in the power system, to be achieved jointly by all installed power plants.

In power systems with a strong presence of wind generation and with a constraint on the minimum reliability level, wind capacity in the optimal mix comes together with some capacity of peaking units that contribute to jointly meet the reliability requirement. The same is true, but typically to a much lesser extent, for conventional technologies with a ratio of the capacity factor to the average availability factor lower than the one for the considered peaking technology.

Wind, in combination with an adequate amount of peaking plant capacity, is a candidate to occupy the base load niche under the load duration curve, therefore competing with nuclear or coal. The winning technology will depend on the corresponding fixed and variable costs, including the costs of the peaking technology, and also on the intensity of the reliability, emission and renewable penetration constraints.

3.5 Summary

The goal of this chapter is to introduce the tools used for the analyses in this thesis: the ReEDS model, the Memphis model and the analytical model. These models all together facilitate the investigations of the impacts of wind energy on the electric power system on both the operational and planning aspects. The direct insights gained from the analytical model have been discussed in this chapter. The following three chapters present the detailed analyses and discussion on the long-term and short-term impacts of wind energy using the three models.

CHAPTER 4. LONG-TERM IMPACT OF LARGE QUANTITIES OF WIND ENERGY ON THE ELECRIC POWER SYSTEM

4.1 Introduction

This chapter analyzes the long-term impacts of integrating large quantities of wind energy into the electric power system. The ReEDS model, along with the analytical model introduced in Chapter 3, will be used for this analysis. The ERCOT power system has been chosen as the primary case example because of its appropriate size and relative independence within the US power system. Different policy scenarios have been developed for the ERCOT case. Discussions are also held at the US national level, but with less detail for simplicity, because of the large volume of information involved. The ReEDS model determines the optimal generation and transmission capacity expansion for both the ERCOT system and the US electric power system for the time span of 2006-2050 and under different policy assumptions. The analytical model is used in parallel to help in the interpretation of the results obtained by ReEDS.

4.2 Scenario descriptions

This section briefly introduces the scenarios that have been developed under different policy assumption for the long-term impacts analysis of wind energy on the electric power system. For the case of ERCOT, three scenarios–one CO_2 policy case and two no-

CO2 policy cases-are developed and discussed. The CO2 policy case is the reference case, with more detailed discussion and sensitivity analysis. For the contiguous US case, a CO2 policy case under the same assumptions as the ERCOT CO2 policy case is presented with a brief explanation.

4.2.1 The EPPA model

Before going into the details of the ReEDS model runs, it is necessary to make a short introduction of the EPPA model. As mentioned earlier, this thesis has been an outgrowth of the research conducted for the MIT Future of Natural Gas study. Consistent with the study of wind impacts on the electric power sector in the Natural Gas study, this thesis does not make independent forecasts for electric demand or CO2 policy-such assumptions are generated by the Emissions Prediction and Policy Analysis (EPPA) model. The EPPA model is a general equilibrium economic model with US as one of its regions. It is a multi-region, multi-sector representation of the economy that solves for the prices and quantities of energy and non-energy goods and projects trade among regions. The advantage of the EPPA model is its ability to explore the interaction of factors underlying energy supply and demand that influence markets. It is able to make projections over the long term under different high-level economic conditions. Such projections are calculated on a five-year time step for any long-term horizon (MIT Energy Initiative, 2010).

4.2.2 Cases for ERCOT and the US

Because of the EPPA model's ability to look at the big picture at a higher level, this thesis uses some key output data from two scenarios generated by EPPA as inputs for ReEDS. These EPPA-generated inputs used for ReEDS include the projection of the total US electric demand from 2006 to 2050, projections of natural gas and coal prices, and the national CO2 emission cap (in cases where it exists). Therefore two scenarios are adapted from EPPA:

CO2 Policy scenario

The EPPA CO2 Policy scenario describes a scenario where a 70% CO2 emission reduction is achieved in 2050 compared with 2005 in the US electric power system, using a price-based policy (such as a cap-and-trade system or emissions tax). The EPPA model decides the CO2 emission reduction path along the time span in a cost effective way. Because of the price elasticity of demand, which is considered in EPPA, under the CO2 policy, the projected demand from 2006 to 2050 is fairly flat (this will be seen in the detailed analysis below), compared with the no-CO2 policy case. In this thesis, ERCOT CASE 1, which is the base case for the long-term analysis, along with the US CASE, are developed from this EPPA 70% CO2 reduction scenario. Meanwhile, ERCOT CASE 2, a parallel case to ERCOT CASE 1, is also presented for comparison. CASE 2 has all the inputs and constraints the same as CASE 1 except that no CO2 policy is imposed. CASE 2 does not take into consideration demand response; therefore the demand trajectory is also the same as that in CASE 1.

No-CO2 Policy scenario

The EPPA no-CO2 policy scenario describes a situation where no CO2 emission regulations are in place. In this scenario the demand projection is much higher than in the policy scenario, because the carbon emission is not considered to be a cost, either implicit or explicitly. Moreover, because of the elasticity of coal and gas prices to the electricity demand, computed by EPPA, the fuel price of coal is also relatively higher in this scenario, compared with the CO2 Policy scenario. ERCOT CASE 3 is thus based on this EPPA policy scenario with the corresponding demand and fuel prices inputs.

For all the cases, in the ReEDS model, the features that represent fuel price elasticity, storage technology and efficiency are turned off, so that the outcome of the sensitivity analysis conducted to explicitly explore the impacts of wind penetration is clearer. Carbon capture and sequestration technologies are only available after 2020, which is consistent with the EPPA model. No specific policy is imposed on other conventional technologies such as nuclear, coal or gas. Figure 4-1 shows the case organization in this chapter.

4.2.1 ERCOT CASE 1 – Base case

Figure 4-2 shows the configuration of the ERCOT system in 2006. This generation technology portfolio is composed of 4.9 GW of nuclear plants, 25.1 GW of CCGT, 6.0 GW of OCGT, 24.8 GW of Gas-steam, 15.4 GW of coal, 10.8 GW of wind, and 0.5 GW of hydro.

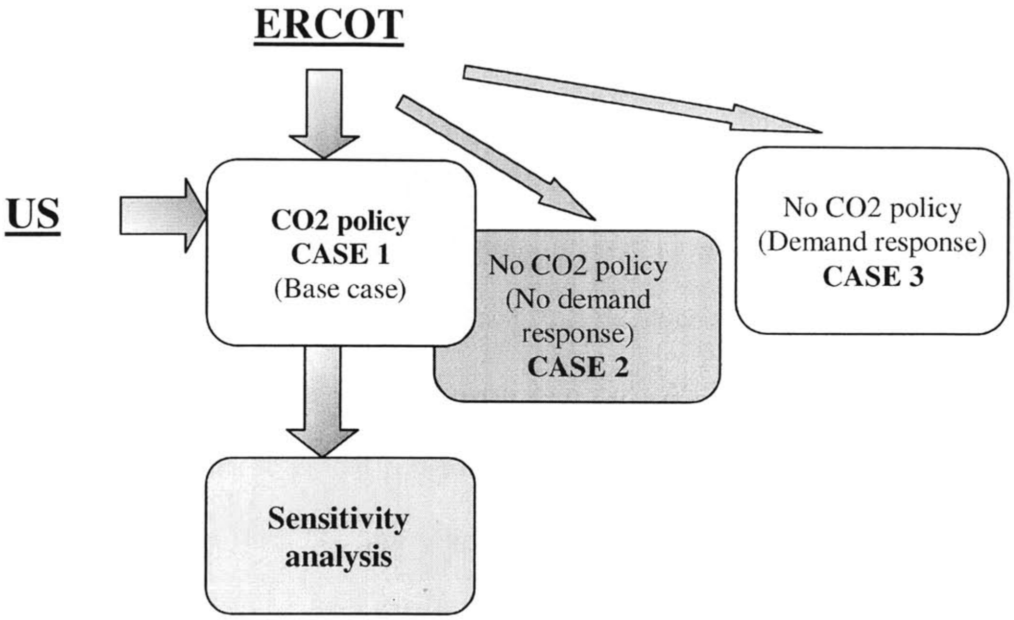


Figure 4-1 Cases for ERCOT and the US for the long-term impacts analysis

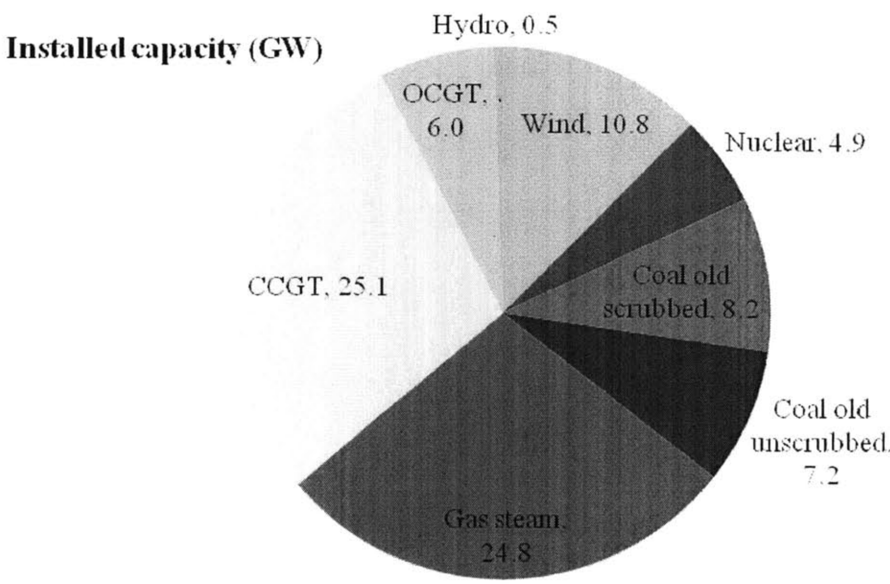


Figure 4-2 Installed capacity mix in 2006 in ERCOT CASE 1 (GW)

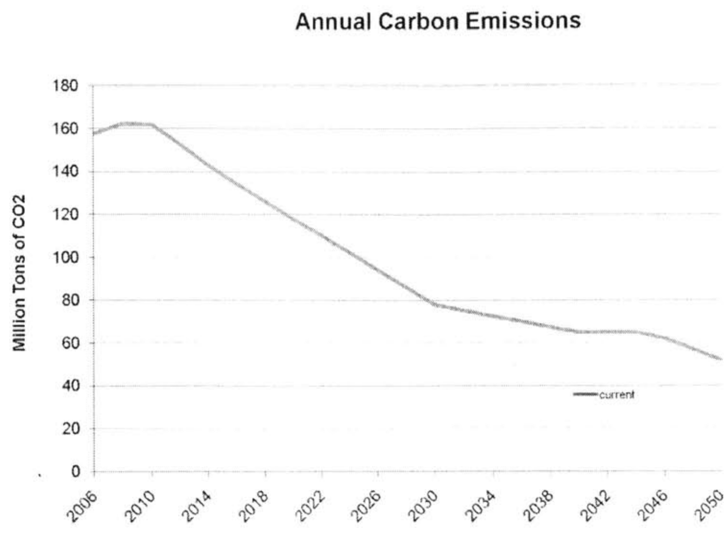


Figure 4-3 Annual CO2 emission trajectory for ERCOT CASE 1 (Million tons)

In this case, the allowed annual total CO2 emissions decrease from 160 million tones[5] in 2006 to around 50 metric tons in 2050. This is an input data independently obtained with the EPPA model.

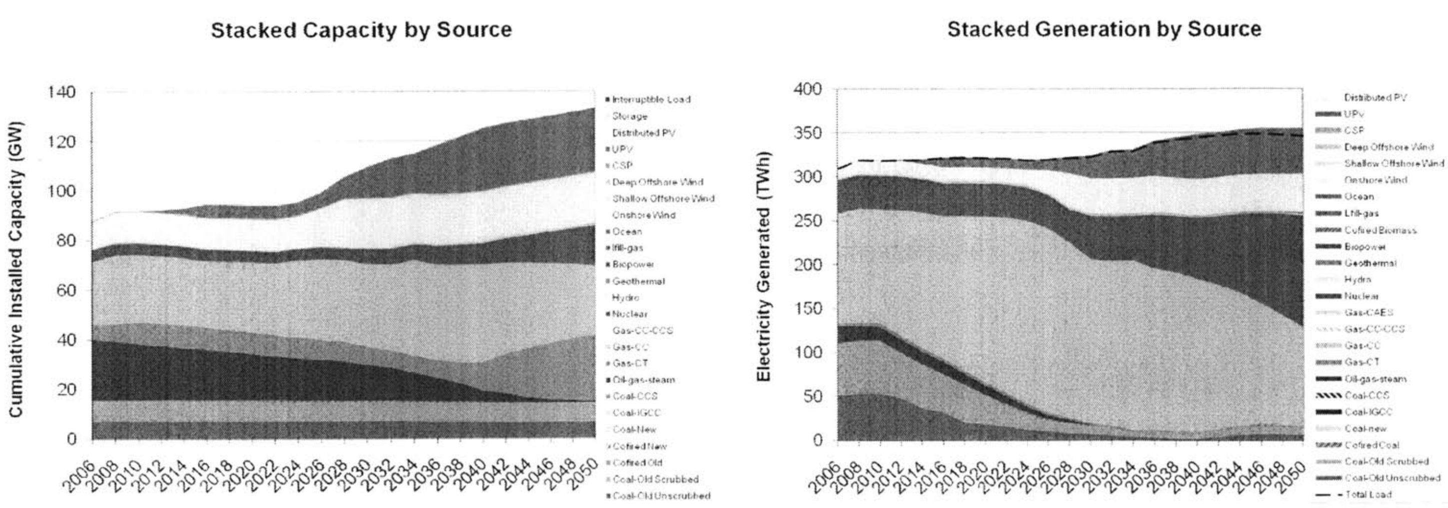


Figure 4-4 Installed capacity and generation trajectory of the ERCOT CASE 1

[5] Note that in this thesis, ton refers to metric ton.

Figure 4-4 shows the installed generation capacity and energy production for the complete trajectory 2006 -2050. Wind penetration reaches 12.6% in 2030 in this scenario.

Regarding electricity generation, a carbon constraint directly calls for more production from less carbon intensive technologies. Therefore, at the beginning of the period, when no significant amount of new capacity can be yet added to the system, the generation dispatch responds immediately by having more energy produced from gas technologies, mostly CCGT in this case, and less energy produced from coal technologies. As the CO_2 emission limit becomes more stringent, this pattern continues until a point where production from coal reaches a very low level while more CO_2 reduction is still required under the carbon constraint. Beginning in 2022, production from onshore wind and solar PV begin to increase. Production from wind reaches a stable level at around 2030, as a result of the limit of the natural resource at a competitive cost level. Similar trajectory happens to solar PV at a later stage. Production from nuclear plants starts to expand as the production from wind and solar PV stop increasing, because of a need for additional emission reduction. OCGT generates very little largely due to its high variable cost, but its capacity is needed for system reliability reasons.

In terms of installed capacity, the level of demand, the operating reserve requirement and the firm capacity margin requirement play the most significant roles in the investment outcomes. First, the various technology capacity sources should be adequate to generate electricity to meet the demand. When the existing capacity in a system cannot produce enough energy to meet the demand subject to the CO_2 emission constraint, new capacity needs to be built. Second, sufficient flexible generating capacity is needed to provide operating reserves to cope with the variability and uncertainty of both the demand and generating capacity sources. Third, as has been introduced in Chapter 2, the difference in the contribution of each type of technology to the system reliability also has a substantial influence on the decision of the addition of new capacity. As can be seen from Figure 4-4, from the beginning of the considered period to around year 2024, except for solar PV, which starts entering the capacity mix since 2010, the overall capacity portfolio remains almost stable with gas steam turbine steadily retiring. During this early period, the system responds to the carbon emission limit mainly through adjustment in the generation dispatch pattern. Wind and solar PV capacities start to expand after 2022 and stop expansion around 2030 for wind and 2040 for solar PV, because the best resources of wind and solar are no longer available beyond the installed capacity. The carbon constraint places the most carbon intensive technologies at a disadvantage. Therefore, although coal and gas steam plants have no resource limitations during the considered period, no new capacity of these technologies is built. As the lifetime of coal is 60 years in the model, the installed capacity of coal technologies is always present during the modeling period. Considering the scarce production from coal technologies, their presence as installed capacity indicates that, in this scenario, a significant fraction of the existing coal plants would have to be idle most of the time, to mitigate CO2 emissions. The installed capacity of gas steam turbines declines as older units reach their lifetime of 30 years. Because of its higher capital costs, nuclear power plants do not expand until later and at a moderate pace, when the expansion of wind and solar ceases. CCGT expands slowly in the earlier years until nuclear capacity enters the picture. Because of its ability to provide spinning reserves and quick start ability, there is always a significant level of installed capacity of OCGT. The installed capacity of OCGT remains at the same level until 2038 and starts to expand when both CCGT and gas steam plant capacity start to decline. This expansion is mostly driven by the system reliability requirement to guarantee a certain amount of reserve margin as the contribution from other technologies decreases.

Table 4.1 shows the change in the capacity factor of each technology. The capacity factors of coal technology and gas steam turbine drop substantially from 2006 to 2050. In contrast, the capacity factor of CCGT increases first, even with new capacity built, as coal production drops from 2006 to 2030 and then decreases as production from nuclear and renewable sources increase. Nuclear, regardless of the change in its installed capacity, operates always at a very high capacity factor, serving as the base loaded technology.

Table 4.1 Comparison of capacity factor vavious technology in 2006, 2030 and 2050 for ERCOT CASE 1

Capacity factor	2006	2030	2050
Nuclear	90%	90%	90%
Wind	13%	24%	24%
Solar PV	-	24%	23%
Coal old scrubbed	82%	15%	14%
Coal cold unscrubbed	81%	11%	11%
Steam turbine	9%	0.3%	0.3%
CCGT	57%	65%	46%
OCGT	5%	3%	0.2%
Hydro	22%	22%	22%

The results obtained by ReEDS for ERCOT CO2 policy case can be further interpreted by the analytical model presented in Chapter 3. First of all, the carbon emissions constraint modifies the merit order of generation dispatch by adding an implicit carbon cost to each technology. This can be observed in this case from the switch between production from natural gas and coal in the early years. Second, as wind penetration increases, in order to mitigate the wind variability and uncertainty, the need for flexible generating technology, in this case OCGT, increases as well. Third, as the system has enough installed capacity of OCGT to cope with the wind variability and uncertainty, this combination of wind and flexible generation technology becomes competitive against nuclear. Therefore, as wind capacity expands, additional installed capacity of nuclear is restricted. Because of the same reason, when wind expansion stops, nuclear starts to expand. It should be noted the competition between wind and other technologies beyond nuclear. As explained in the analytical model, when nuclear is restricted by the expansion of wind, the competition and corresponding displacement would extend further to the technology next to nuclear in the dispatch merit order, which is coal. However, as coal is already confined by the limit on CO2 emission, it is natural gas (CCGT) that is affected. Therefore, which technology is in direct competition with wind is decided by the interactions between a number of factors, such as the adequacy of flexible generation, the policy on CO2 emission, the volume of other technologies, etc.

4.3.1 ERCOT CASE 2 – No CO2 policy without price elasticity of demand

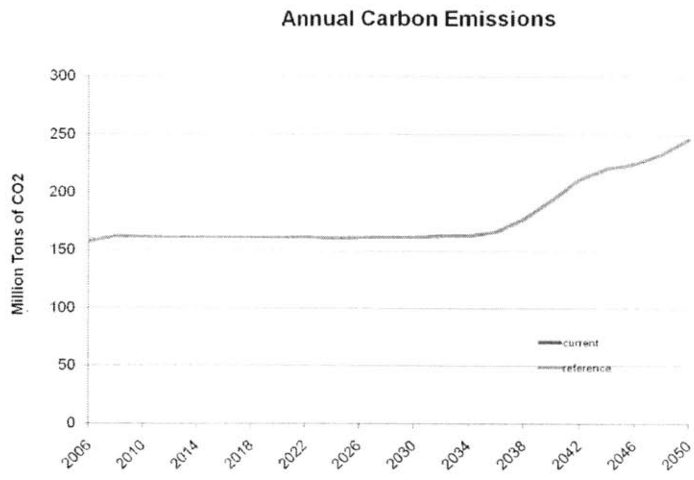


Figure 4-5 Annual CO2 emissions trajectory in ERCOT CASE 2 (Million tons)

With all other conditions being the same and assuming that demand remains the same as in the reference case (this assumption is removed in the next section), the absence of a carbon constraint in the previous case example results in a substantially different future capacity mix. Without any policy to limit CO2 emissions, the total CO2 emissions grow significantly in this scenario, because of the use of cheaper but more carbon intensive technologies. Figure 4-5 shows the total CO2 emissions in 2006-2050 in a carbon emission free scenario.

Figure 4-6 shows the trajectory of generation and installed capacity of ERCOT CASE 2. For generation, as demand remains basically at the same level in the beginning years, the system keeps operating in a similar dispatch pattern with basically the same initial capacity mix, before new capacity is added. In later years, when demand increases mildly and a proportion of the older units, particular gas steam tubines, retire, energy production from coal tops other generation technologies to displace production from CCGT first and later nuclear when nuclear capacity starts to retire. Nuclear operates at a constantly large capacity factor because of its low variable costs until the time when some of the capacity starts to retire.

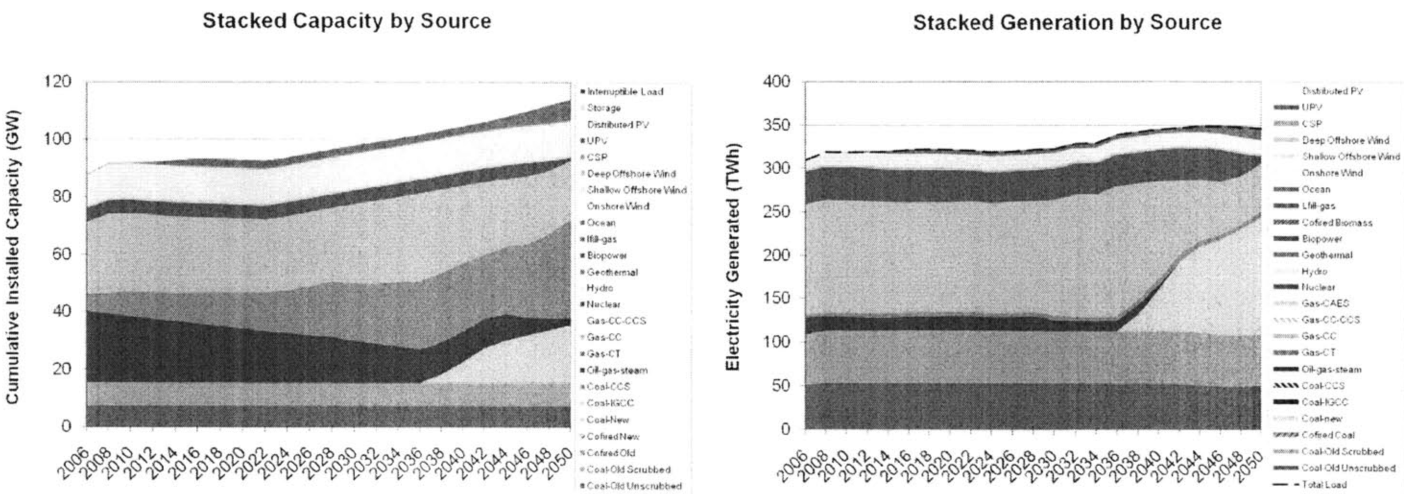


Figure 4-6 Installed capacity (GW) and generation (TWh) trajectory in ERCOT CASE 2

In terms of installed capacity, since the cost of carbon emissions is not internalized in the system, the investment decisions in new installed capacity depend solely on the relative costs of each technology and the constraints on system realiability and security. New installed capacity added to compensate the retirement of old plants is driven by two types of system needs: one is the constraint to meet the demand, whereby coal, which has the highest return on investment, is built; the other is the need for firm capacity to meet the firm capacity margin requirement. As gas steam turbine gradually retires, both OCGT and CCGT start to pick up to maintain a certain level of firm capacity. After around 2038, CCGT capacity stops growing and starts to diminish as coal capacity is added in. Around

2046, nuclear starts to retire and gas steam turbine continues to diminish. Even coal capacity is increasing, as demand is increasing, the requirement for firm capacity also increases. Therefore more OCGT capacity keeps being added into the mix despite that their capacity factor is very low.

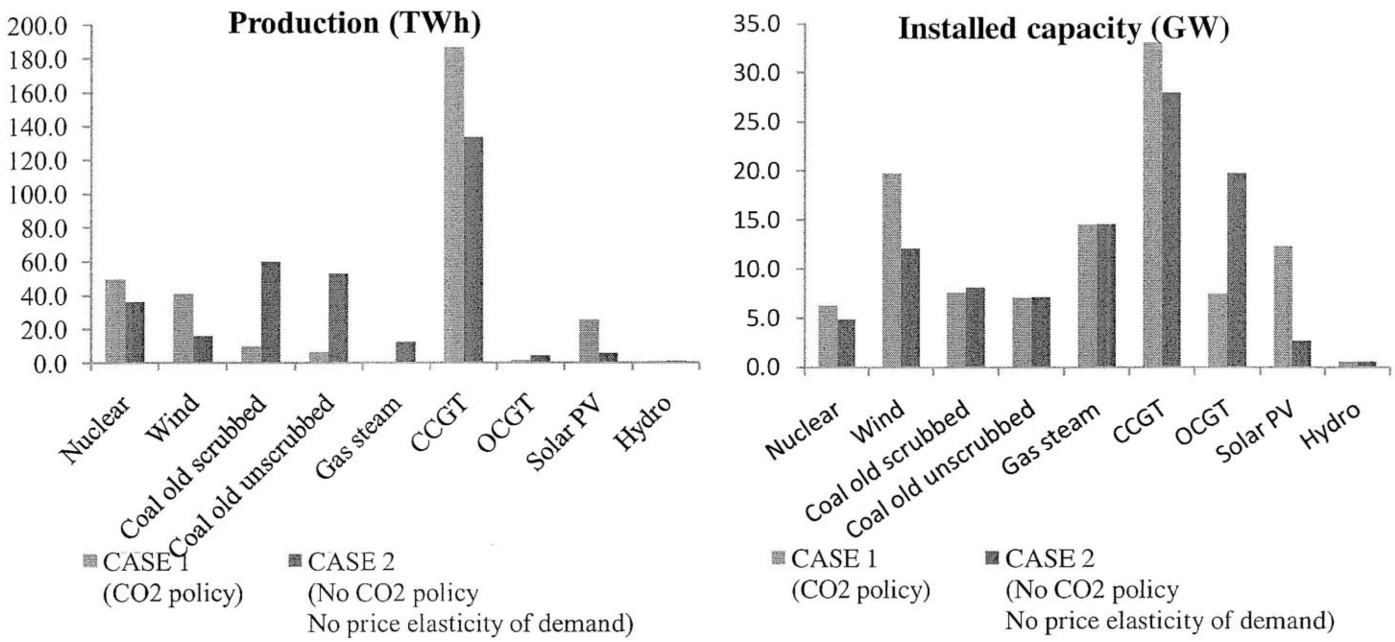


Figure 4-7 Comparison of installed capacity (GW) and production (TWh) for year 2030 of ERCOT CASE 1 and CASE 2

In this case, production from wind remains at the same initial level throughout the considered period. Its penetration reaches only 5.0% in 2030 and 4.8% in 2050 when solar PV enters more into the system. Therefore, in a scenario where carbon emissions are unrestricted, wind energy is less likely to grow at the current and anticipated costs. Figures 4-7 shows the comparison of installed capacity and energy production in ERCOT CASE 1 and ERCOT CASE 2 for year 2030. In general, more installed capacity and production of CO_2 intensive technologies takes place in CASE 2 where CO_2 emissions are not capped.

4.3.2 ERCOT CASE 3 – No CO_2 policy with price elasticity of demand

The significant increase of demand in ERCOT CASE 3 with respect to the reference CASE 1 shows the effect of the difference in the demand response to the price of electricity, which in CASE 3 does not include any carbon price. As a result, the power system needs to expand to a greater extent to meet the increased demand.

Similar to CASE 2, technologies that require extensive investment in capital costs, such as nuclear, are now at disadvantage, with no new capacity added. Production from wind remains stable until the very end of the period, when it slightly increases to meet the high demand level. This increase in the end is also partly because of the relatively higher fuel price of coal against gas in CASE 3 than in CASE 2, as introduced earlier. This makes coal technology expansion less rigorous in CASE 3 than in CASE 2. Similar to CASE 2, production from nuclear declines, when its installed capacity starts to retire, With the lowest capital cost, OCGT installed capacity expands significantly as steam turbine capacity retires, in order to provide adequate firm capacity. In the later years on the trajectory, despite that coal and CCGT capacity increases, OCGT capacity still increases, because of its quick-start ability to provide operating reserves, needed to cope with the increased penetration of wind energy. This has been observed in all the cases discussed above.

Different from CASE 2, the installed capacity of and production from CCGT increase at a steady pace following the increasing trend in demand, surpassing the expansion of coal technologies, which only start to expand in later years. Again, with the relatively lower gas price in CASE 3 and the ability to provide spinning reserve, the expansion of CCGT takes place, as an economic approach, to meet the higher demand level, the operating reserve requirement, and the firm capacity margin requirement.

Figure 4-9 shows the comparison of installed capacity and energy production in ERCOT CASE 2 and ERCOT CASE 3 for year 2030. In ERCOT CASE 3, the installed capacities of natural gas technologies are noticeably more than in ERCOT CASE 2. The installed capacity of nuclear, wind and coal technologies, however, are basically the same in both cases.

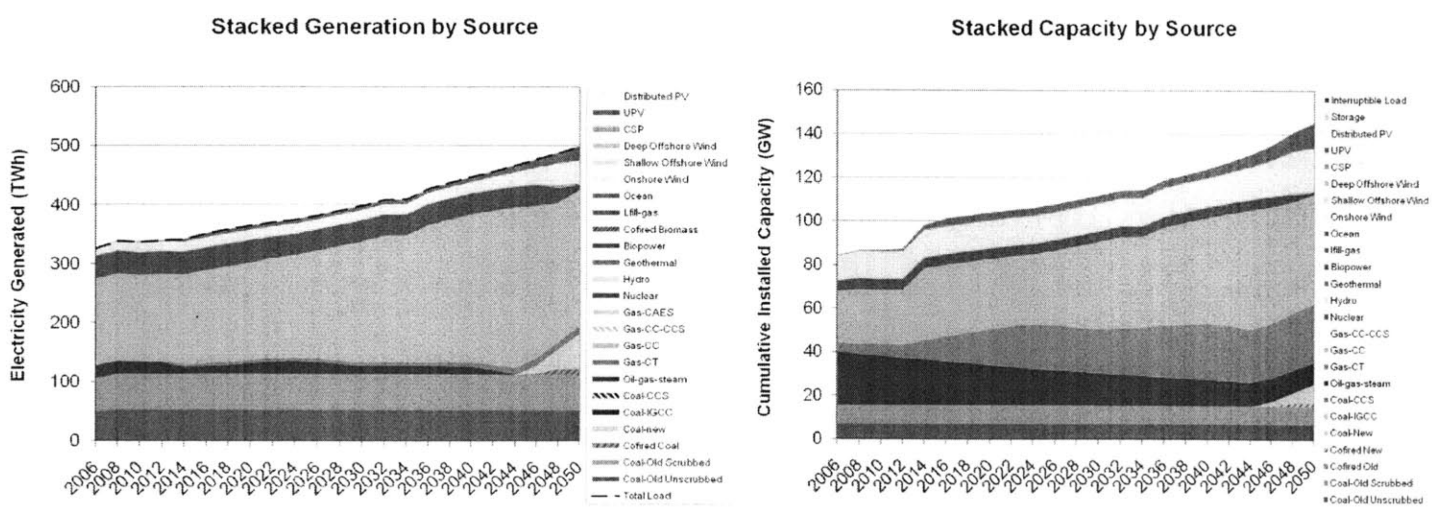


Figure 4-8 Installed capacity (GW) and production (TWh) trajectory of ERCOT CASE 3

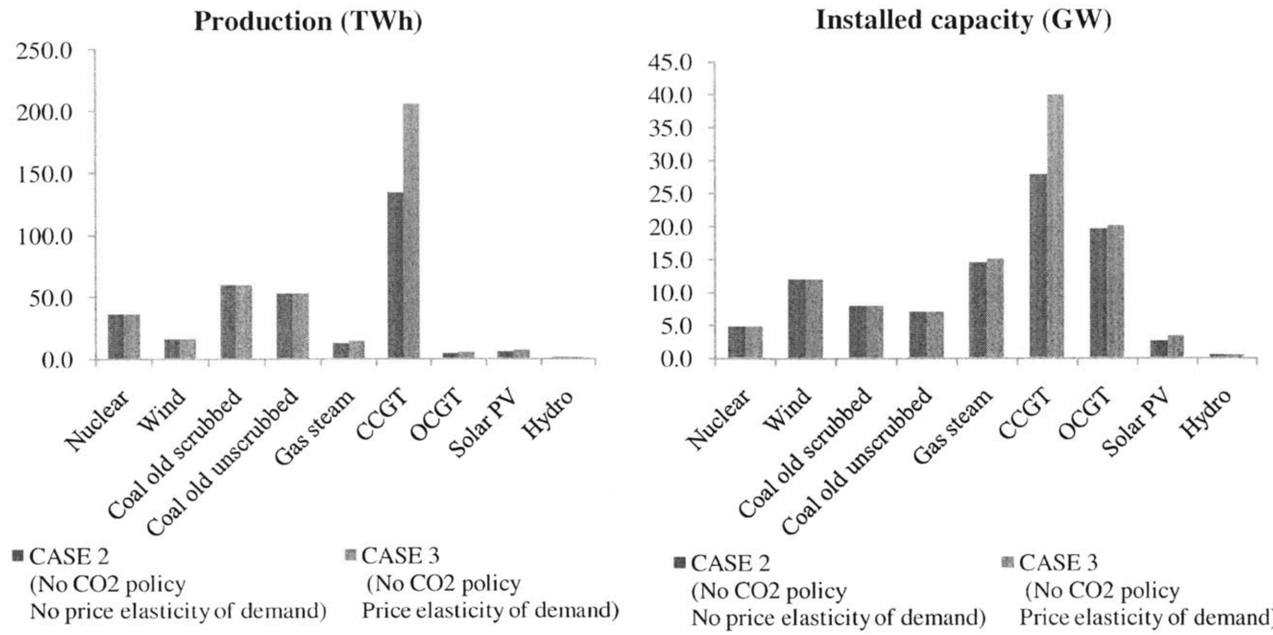


Figure 4-9 Comparison of installed capacity (GW) and production (TWh) for year 2030 of ERCOT CASE 2 and CASE 3

4.3.3 US CO2 Policy CASE

Under the same assumptions for ERCOT CASE 1, a CO2 policy case is conducted at for the contiguous US in order to present a bigger picture. The annual CO2 cap trajectory is shown in Figure 4-11. The expansion results for the US case are more complex to interpret because they correspond to an aggregation of several relatively independent but interconnected regions with different natural resources and initial technology mixes. Figure 4-11 shows the trajectory of installed capacity and energy production for the US CO2 Policy CASE from 2006 – 2050.

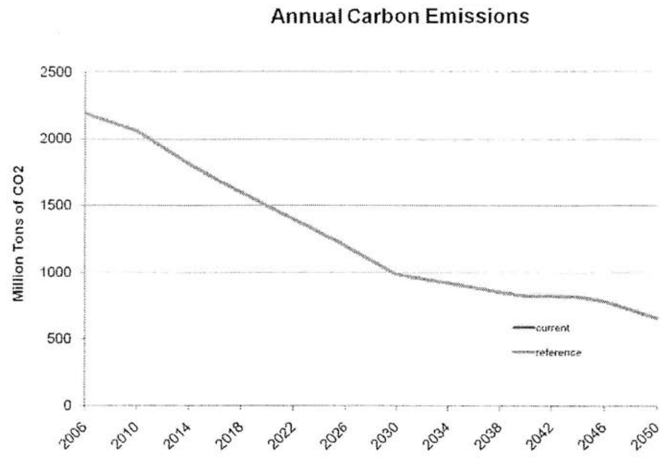


Figure 4-10 Annual CO2 emissions trajectory for the US CO2 Policy Case (Mtons)

In terms of energy production, in the early years of the analyzed period, similar to ERCOT CASE 1, the system responds to the CO2 emission constraint mainly through adjustment of the generation dispatch pattern. While production from nuclear remains at a stable level, production from CCGT displaces production from coal technologies, to reduce CO2 emissions in the system. Production from both onshore wind and solar expand since the very beginning and the trend becomes stronger in a later stage when production from coal is already reduced to a very low level, while the pressure to reduce annual total allowed CO2 still increases. Around year 2032, shallow offshore wind begins to enter as well because it is economically competitive under the carbon constraint. At the same time, production from nuclear begins to decrease and the expansion of CCGT production ceases first and then shrinks when wind plays a larger role in the system.

Regarding installed capacity, onshore, shallow offshore wind and solar PV are added at a remarkable pace during the whole period, as carbon policy gets more stringent. CCGT capacity expands in the early years and then remains stable (although production gradually reduces) as wind penetration starts to take a significant role in the system. As already seen in ERCOT CASE 1, OCGT capacity expands in line with the expansion of wind and the retirement of gas steam turbines, built to ensure both the operating reserve requirement and the system reliability requirement. Except for the retirement of some of the capacity, coal technology is always present because of its longer lifetime. Nuclear capacity, in contrast to the ERCOT CASE 1, declines due to retirement, without any new added capacity at around year 2026.

The results for the US case are in agreement with the insights that been discussed earlier in the analytical model. At national level, the wind resource is sufficient for the wind technology capacity to expand optimally (although the ReEDS model takes into account any required costs of transmission network expansion). The expansion of wind, combined with enough flexible new OCGT capacity, competes with the rest of technologies, starting from the base loaded ones and upwards in the dispatch merit order. Because wind capacity expansion takes place throughout the whole period, nuclear capacity is restricted from expansion. Since coal capacity is already reduced by the CO2 emission constraint, it cannot compete with the combination of wind and OCGT. Thus, wind expansion ends up restricting the expansion of CCGT.

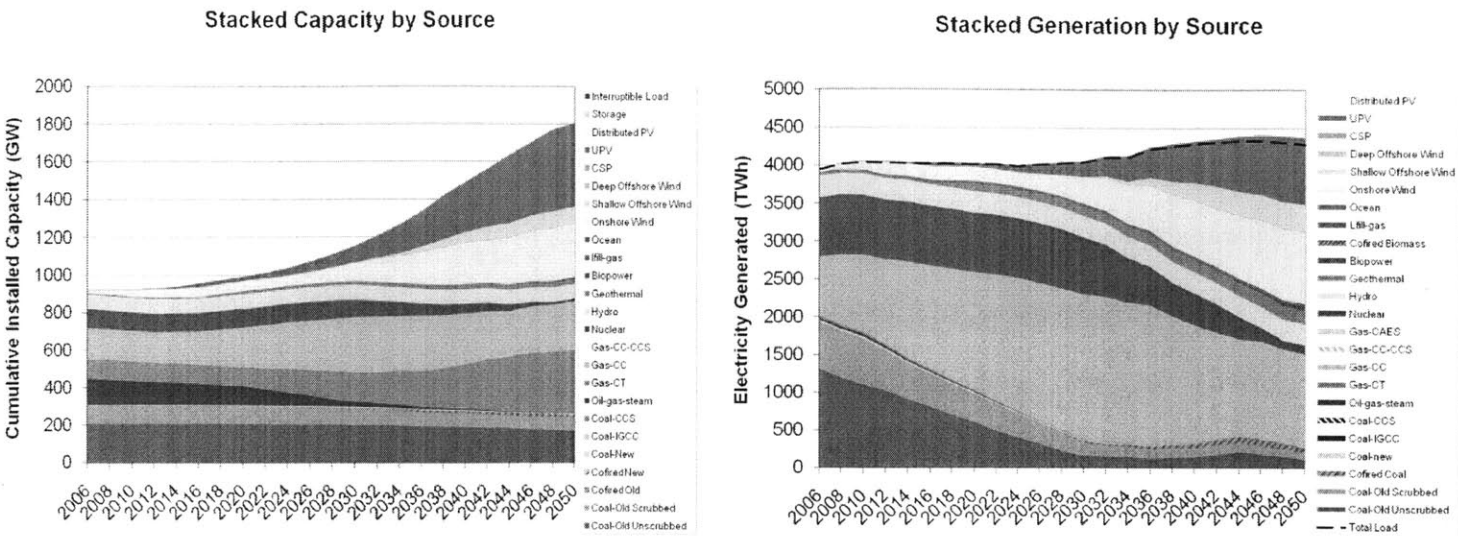


Figure 4-11 Installed capacity (GW) and generation (TWh) trajectory of the US CO2 Policy Case for year 2030

4.4 Wind penetration sensitivity analysis

4.4.1 Introduction

Since the cases analyzed above only allow analyses and discussion at a specific wind penetration level, sensitivity analyses were performed to further investigate and quantify the impacts of large quantities of wind energy, i.e., the sensitivity of the technology mix and the productions to different levels of significant wind penetration.

Given the structure of ReEDS, whereby it calculates the capacity expansion by optimizing the total cost on a two-year step, a wind penetration target for the final year would only affect the optimization results of the last two years. Therefore, in order to obtain how the power system would respond to different levels of wind penetration, an alternative approach is taken by adjusting the costs of wind technologies, which implicitly increases or decreases the penetration levels of wind without creating additional non desired interactions between wind and other technologies. Because of the high likelihood of a future carbon constrained environment, the two CO2 policy cases, ERCOT CASE 1 and the US CO2 POLICY CASE are selected for wind penetration analysis. Two sensitivity cases, a low wind case and a high wind case, are performed for each of the two base cases.

- Low wind case: in this case, the key cost components of all wind types, including capital cost, fixed cost and variable costs are increased, by 50% for ERCOT CASE 1 and by 10% for US CO2 Policy CASE, making wind less competitive compared with the reference cases.
- High wind case: in this case, the same cost parameters are reduced, by 50% for ERCOT CASE 1 and by 5% for US CO2 Policy CASE, making wind more competitive compared with the reference cases.

For the ERCOT case, a sensitivity of 50% is performed so that stable responses of the system to the change of wind penetration can be observed to filter out some noise behaviors. Moreover, for a region of relatively smaller scale, large changes of wind penetration are more likely to happen. For the contiguous US case, in contrast, an overall change of 50% in costs would result in tremendous change in the penetration levels of wind energy and such a change would be overly huge for the contiguous US. Therefore, in the Low wind case, a sensitivity of 10% is performed. In the High wind case, for the similar reasons mentioned above, an even smaller sensitivity of 5% is selected so that the penetration of wind increases to a more reasonable level from the reference case.

4.4.2 Sensitivity analysis for ERCOT CASE 1

Figures 4-12 shows the installed capacity and the energy production in the two sensitivity cases.

For the Low wind case, generation dispatch is basically the same as in the reference case -ERCOT CASE 1 until about 2024, because the requirement to reduce CO2 emissions can be realized through the modification of the dispatch pattern to operate CCGT more and coal plants less. Due to the high cost of wind in this case, wind is less competitive and thus the production remains almost at the same level during the period. Therefore, the savings in CO2 emissions that would otherwise happen with more wind have to be compensated by further reducing the production from coal and increasing the production from cleaner technologies such as nuclear and natural gas. Regarding the installed capacity, the major difference between the Low wind case and the reference case is the additional nuclear capacity in the Low wind case. The rest of the capacity mix is basically the same. Therefore, the major competition in terms of capacity expansion is between wind and nuclear.

For the High wind case, with lower wind costs, shallow offshore wind also becomes competitive and enters into the generation mix. Production from nuclear does not expand until around 2040, compared with 2034 in the base case. Production from CCGT is significantly less than in the base case as well. Coal technologies, however, operate at a higher level after offshore wind enters, compared with the base case. The system behavior is determined by the CO2 constraint. Since, in the base case, the CO2 emissions are already capped, in the High wind case, any additional wind will relax the CO2 emission constraint on the rest of the system. In other words, with more wind, the cost of carbon emissions for the rest of the system is lower or, equivalently, there is more margin to produce with technologies that emit CO2. Therefore, there will be an increase in production from existing or new CO2 emitting technologies with the lowest variable costs. Regarding the installed capacity, coal technologies, operating at a low capacity factor, remain almost at the same amount. Wind installed capacity increases at the expense of nuclear and CCGT. Again, the trajectory of installed capacity in this High wind case shows a clear competition between different types of wind and nuclear, as has been discussed earlier. Offshore wind starts entering into the system after onshore wind reaches the economic resource limit. More nuclear capacity starts to be added into the system only after offshore wind also reaches its resource availability. Similar to other cases, the addition of OCGT is positively correlated to the addition of wind capacity.

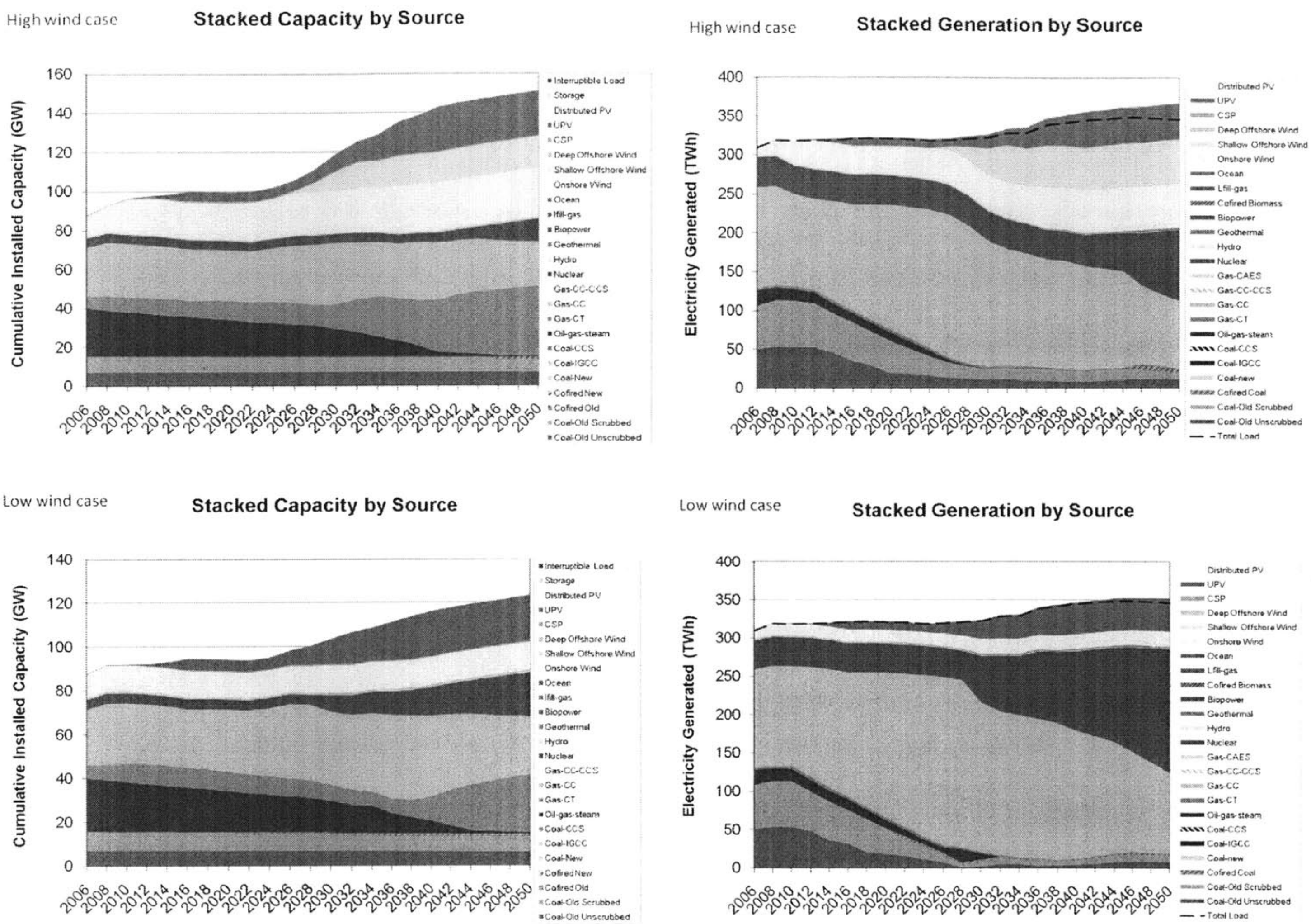


Figure 4-12 Installed capacity (GW) and generation (TWh) trajectory for the High wind case and the Low wind case for ERCOT 2030

This sensitivity analysis can be more easily quantified by looking at a "snapshot" of year 2030 of the trajectory. The incremental changes of other technologies both in terms of installed capacity and energy production are calculated when 1 TWh more of production from wind is added to the system at the same demand level, as shown in Figure 4-13 and Table 4.2 show.

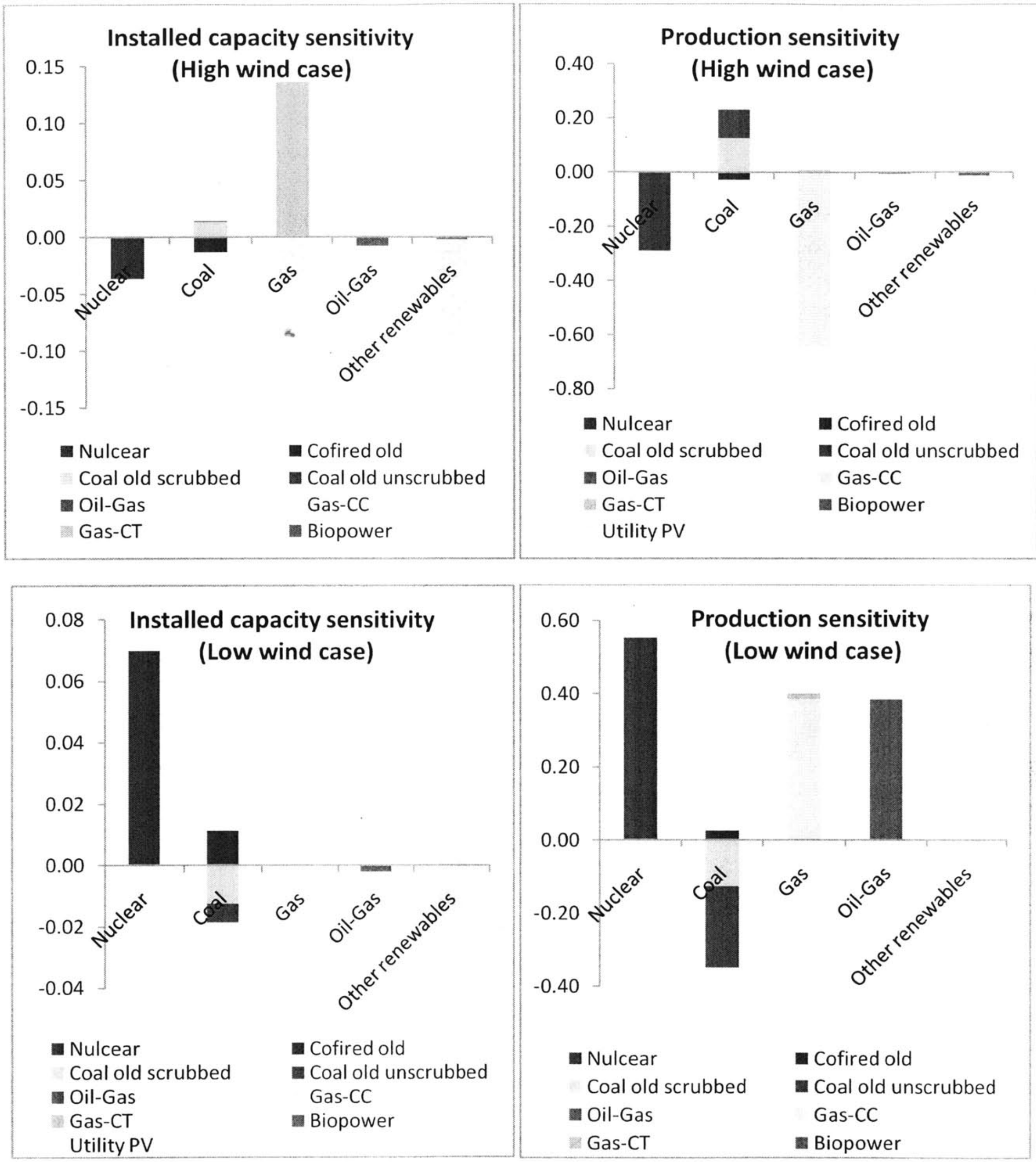


Figure 4-13 Long term sensitivity of the annual installed capacity and production of various generating technologies to an increment of +1 TWh in the production of wind in 2030 for the ERCOT case

Table 4.2 Long term sensitivity of the annual installed capacity and production of various generating technologies to an increment of +1 TWh in the production of wind for the ERCOT case

	Nuclear	Coal old scrubbed	Coal old unscrubbed	Steam turbine	CCGT	OCGT	Solar PV
Production (TWh)	-0.42	-0.03	0.13	-0.19	-0.51	0	0.02
Installed capacity (GW)	-0.05	-0.01	0.01		-0.03	0.07	

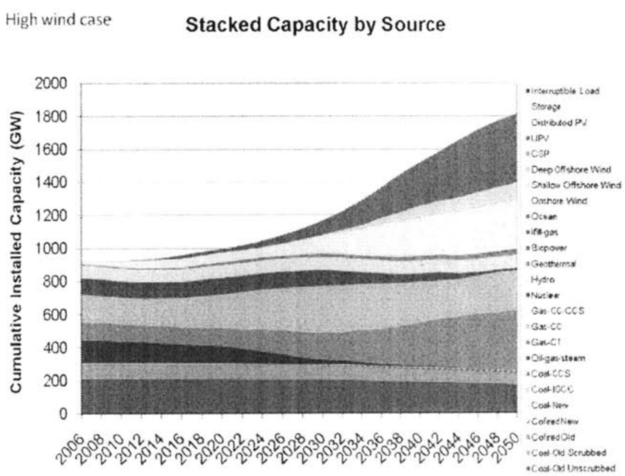
For an increment of +1 TWh in the production (and also the corresponding amount of installed capacity, obviously) from wind energy, production from CCGT is affected the most by decreasing 0.51 TWh. Production from nuclear is also affected significantly by a reduction of 0.42 TWh. Production from gas steam turbines decreases by 0.19 TWh. In contrast, coal production increases by 0.1 TWh. OCGT, which produces very little in the base case, still produces very little. The installed capacities of nuclear and CCGT, in correspondence to what happens in production, reduce by 0.05 GW and 0.03 GW when +1 TWh of wind production is added. The total coal capacity is not affected. OCGT, however, sees an increase of 0.07 GW in the installed capacity.

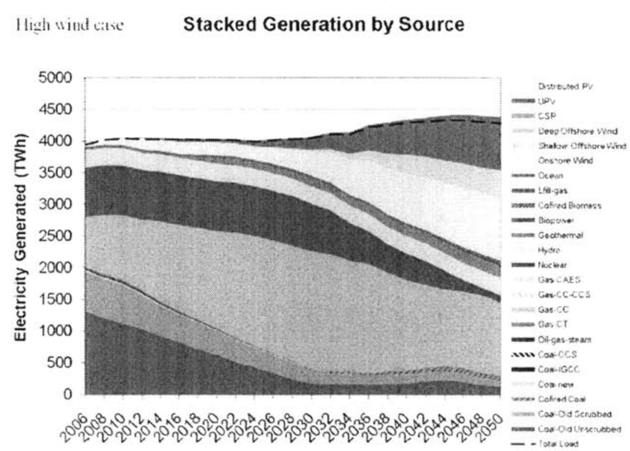
4.4.3 Sensitivity analysis for the US CO2 Policy CASE

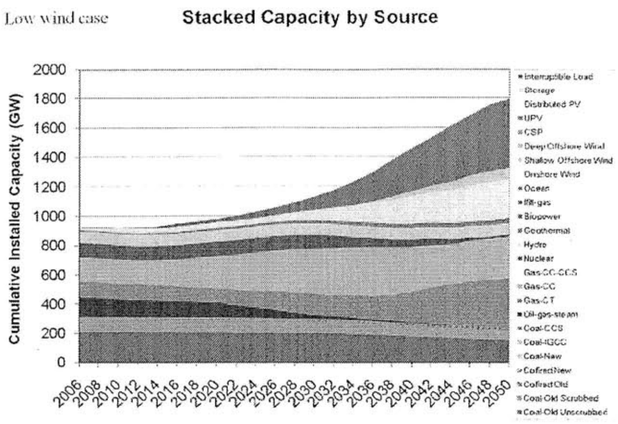
Similar sensitivity analyses are performed for the US CO2 Policy CASE by conducting the High wind and Low wind cases.

Different from the ERCOT case, with the cost inputs used for these case, nuclear does not further expand from the existing capacity and therefore is not in direct competition with wind at the contiguous US level, even in the Low wind case where all the cost parameters of wind are increased by 10%. Therefore, in both the High wind and Low wind sensitivity cases, nuclear capacity does not expand. At very low operating costs, it operates at a high capacity factor in both cases, contributing with the same amount to the generation portfolio. Coal capacity is restricted by the CO2 emission constraint but production in the High wind case is larger compared with that in the Low wind case, in agreement to what has also been observed in the ERCOT sensitivity cases. As discussed earlier for the analytical model, the combination of wind and enough flexible generating technology competes with the base load technology, which is nuclear in this case. If nuclear is already economically not competitive with wind plus OCGT, and coal, which is next to nuclear in the merit order, cannot be expanded because of emission constraints, the addition of wind displaces CCGT capacity that would otherwise happen.

The same approach has been employed for the US sensitivity analysis to compare the incremental change of production and installed capacity of other technologies in 2030, with 1 TWh of wind production added to the system, as Figure 4-15 and Table 4.3 show.







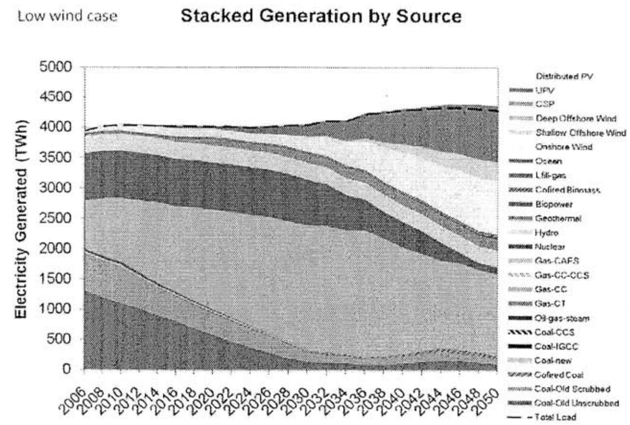
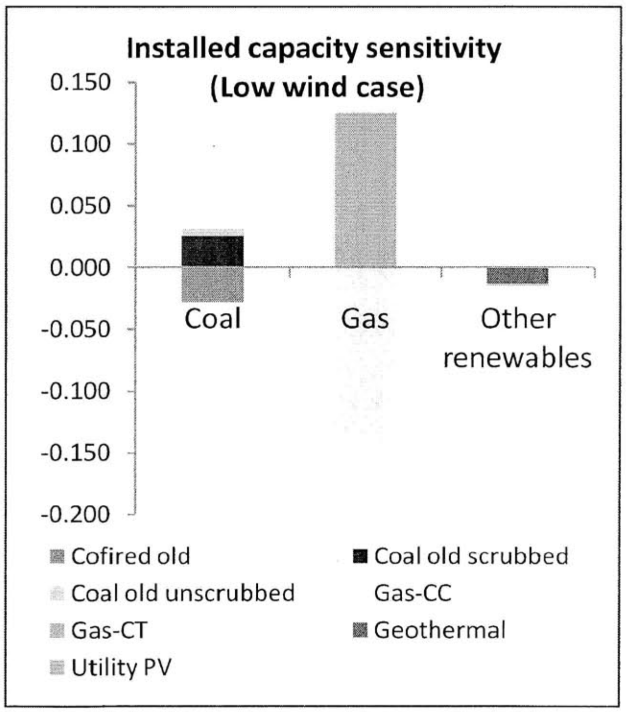
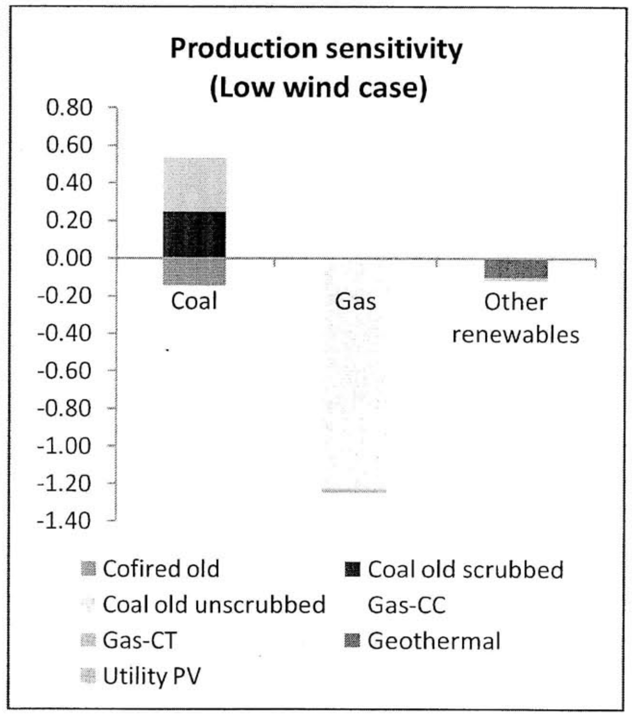


Figure 4-14 Installed capacity (GW) and generation (TWh) trajectory for the High wind and Low wind sensitivity cases for the US





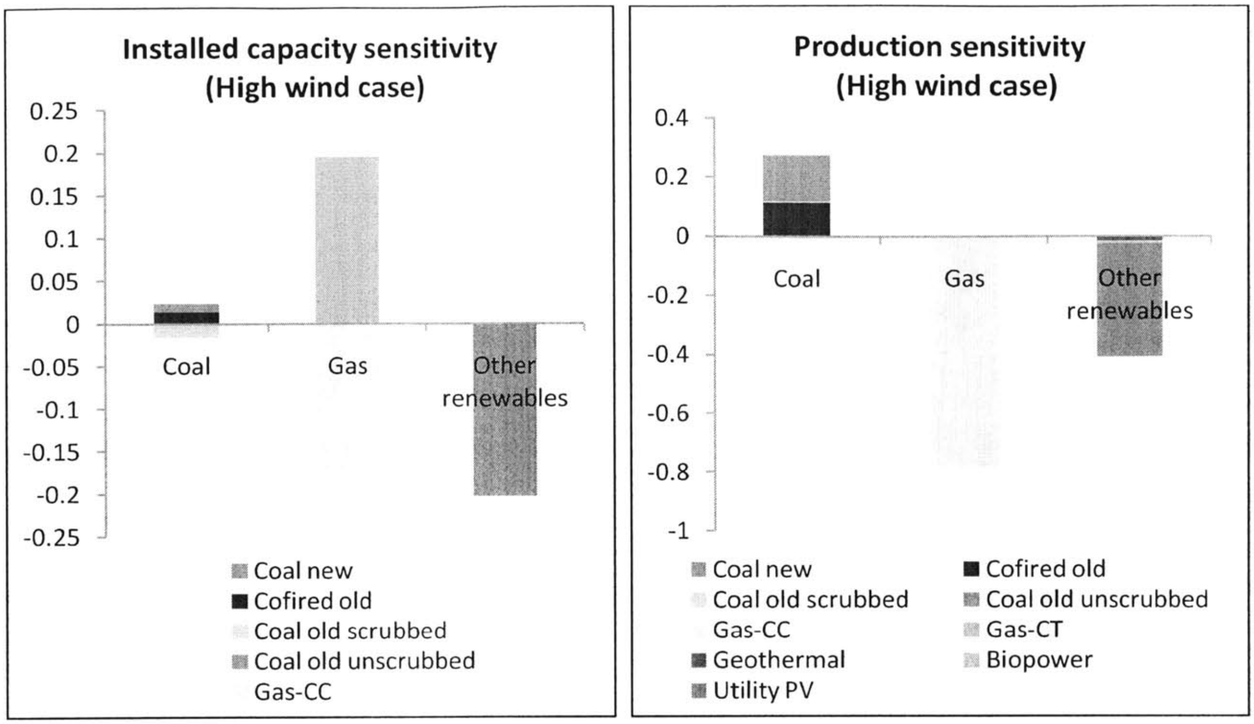


Figure 4-15 Long term sensitivity of the annual installed capacity and production of various generating technologies to an increment of +1 TWh in the production of wind in 2030 for the US case

Table 4.3 Long term sensitivity of the annual installed capacity and production of various generating technologies to an increment of +1 TWh in the production of wind for the US

	Nuclear	coal old scrubbed	Coal old unscrubbed	Steam turbine	CCGT	OCGT	Geothermal	Solar PV
Production (TWh)	0	0.21	0.25	0	-1.44	0.01	-0.05	0.02
Installed capacity (GW)	0	0	0	0	-0.21	0.16	0	0.01

Table 4.3 summarizes these long-term impacts on both capacity investment and production for the 2030 generation portfolio. Under the assumptions and inputs for the analyzed cases, for an additional 1TWh output of wind, the most affected technology is CCGT, whose installed capacity is reduced by 0.21 GW and whose production is reduced by 1.44 TWh. The production from coal increases by 0.46 TWh without any change in

installed capacity. The installed capacity of OCGT is increased by 0.16 GW, but the production from OCGT is very little in all cases.

Therefore, under a carbon constraint, in both the ERCOT and the US cases, CCGT is the most affected technology by wind penetration, both in terms of production and installed capacity. Production and installed capacity of nuclear could also be affected, depending on whether wind penetration is economically competitive against nuclear. If wind is economically competitive against nuclear, as in the US case, nuclear capacity will not be added into the mix. However, the existing capacity is always fully utilized as base load technology. In this case, more wind will have no impact on the operation of existing nuclear capacity. Conversely, if wind is less competitive than nuclear that nuclear capacity is already expanding to meet future demand, the addition of wind would imply less need to build more nuclear capacity, thus showing an impact on the nuclear expansion, as seen in the ERCOT CASE.

In the cases explored here, as wind is already competitive against coal, because of the carbon constraint, more wind does not result in more coal capacity. However, although coal capacity does not grow, an increment of wind production also creates a slack for CO2 emissions. Under the same CO2 constraint, therefore, slightly more coal production from existing capacity can be observed. The installed capacity of OCGT, in contrast to other technologies, is affected positively by wind because it is needed to guarantee system reliability, but production remains very scarce.

4.5 Summary

This chapter explores the potential impacts of large quantities of wind energy on the optimal technology mix and production in a power system, under different carbon policies in the long run. Through sensitivity analyses, this chapter quantifies the impacts of wind on both the installed capacity and production of conventional generation, for both the ERCOT case and the US case.

A first, and fairly obvious conclusion from the analysis, is that wind energy is less likely to develop in a world where CO2 emissions are not restricted. Under the CO2 policy assumptions used in the ERCOT and US base cases, the current system could experience significant transition to one that is sufficiently reliable to accommodate a strong penetration of wind energy.

Second, very different generation patterns, compared with the current ones, could also appear in future power systems with large quantities of wind energy. The increase in wind energy may be in competition against the expansion of other technologies. However, which technology could be most affected depends on multiple factors including both the conditions of the specific system as well as the carbon policy implemented. Therefore, it is important for regulators and policy makers to be aware of these impacts when designing energy policy strategies such as quotas for renewables, carbon levies or incentives to guide market behaviors. Chapter 5 will explore the short-term impacts of wind energy in a future scenario with significant presence of wind penetration.

CHAPTER 5. SHORT-TERM IMPACTS OF LARGE QUANTITIES OF WIND ENERGY ON THE POWER SYSTEM

5.1 Introduction

This chapter analyzes the short-term impacts of integrating large quantities of wind energy into the electric power system. "Short-term" is defined in the context of this thesis as a period of time in which the system can only respond to the changes, such as a change in the carbon policy, or a change in renewable energy, by adjusting the pattern of operation. In other words, the installed capacity of each type of technology does not change throughout the considered time period in the analyzed cases. Such analyses are conducted from two perspectives: one is closely related to the long-term impact analysis discussed in Chapter 4. In Chapter 4, the capacity expansion path of a power system to reach a certain level of wind penetration is analyzed. Two independent short-term analyses are performed in this chapter. In the first one, taking a future "snapshot" year as the base case, its behavior for different levels of wind penetration is examined. The second analysis investigates how the operation of a system with a large wind penetration responds to different levels of operating reserves.

Two power systems are studied for the purpose of this chapter: the ERCOT power system and the Spanish power system. The ERCOT system is analyzed for similar reasons as for the long-term analysis, as well as for the purpose of benchmarking the ReEDS model with the Memphis model. The Spanish power system is selected because very complete sets of input data are available from the developers of the Memphis model, in particular regarding wind output and forecast time series. To avoid redundancy, sensitivity analysis on wind penetration level is performed on the ERCOT case and sensitivity analysis on the optimal reserve requirements is performed for the Spanish case.

5.2 The ERCOT Case

5.2.1 ERCOT 2030 Basecase

In this section it is analyzed the generating dispatch pattern of the ERCOT system for year 2030 under the CO2 Policy scenario, ERCOT CASE 1, from Chapter 4. The generation capacity portfolio of conventional technologies, which is required as input of Memphis, is taken from the "snapshot" year 2030 from the ReEDS projection in ERCOT CASE 1 (See Figure 4-2 in Chapter 4).

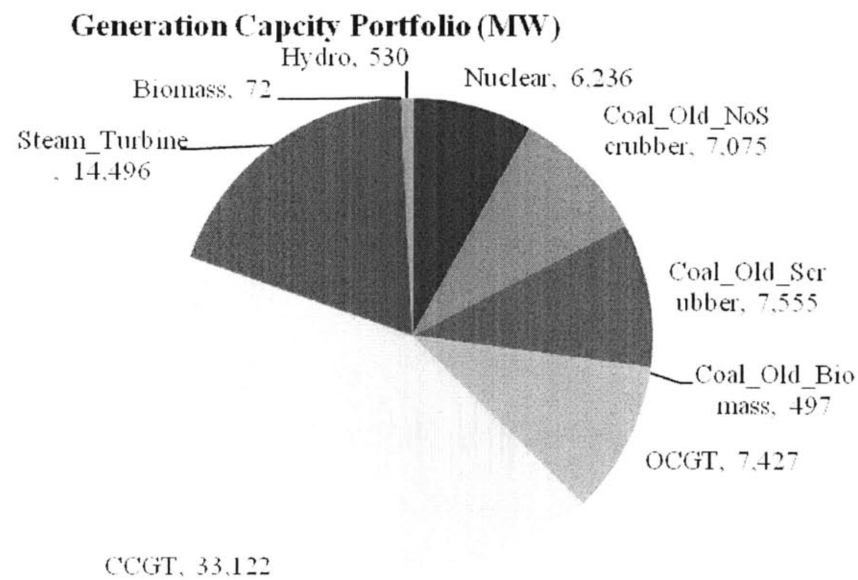


Figure 5-1 Installed capacity of various technologies in the ERCOT 2030 Case (MW)

Conventional generating capacity in this portfolio includes a large share of CCGT, a fair amount of gas steam turbine, coal, nuclear and OCGT. This portfolio, however, does not have a significant amount of hydro capacity. Since this capacity portfolio has been developed in ReEDS to an adequate level, the lack of flexible hydro storage plants implies the need for the presence of enough flexible capacity from conventional technologies.

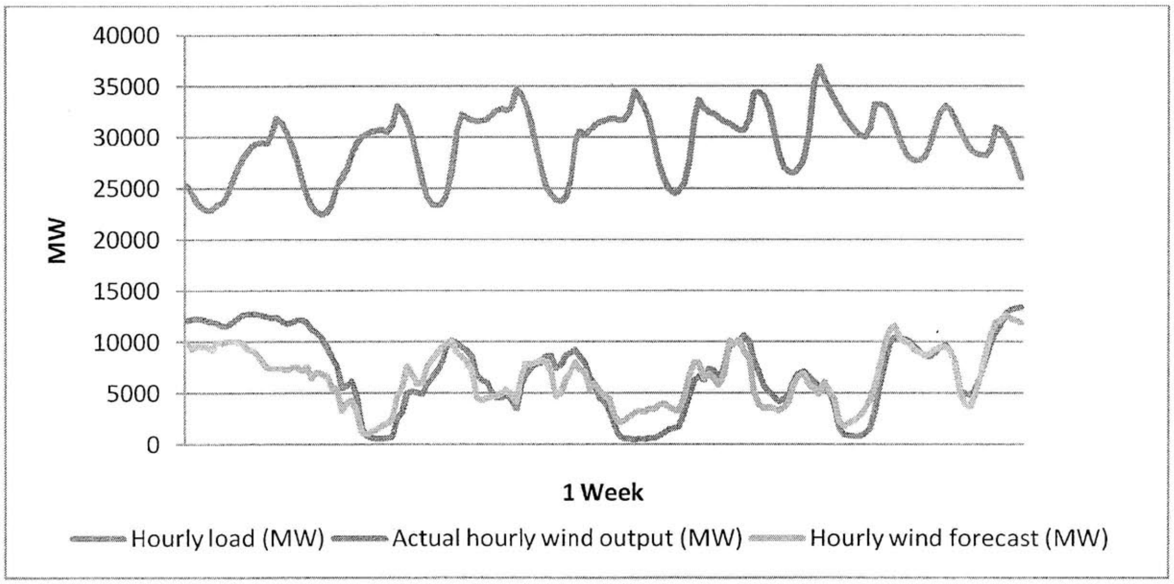


Figure 5-2 Sample hourly load, wind profile and wind forecast used in the ERCOT case

Figure 5-2 shows a sample period of one week of hourly load and corresponding wind profile and the 14 hours ahead wind output forecast used in the Memphis simulation for ERCOT. The correlation between load and wind output profile is important for the dispatch pattern. As shown in the figure, wind forecast can capture the overall trend of the actual output, but the forecast error could be large in coincidence with times when demand is high, which would require a sufficient amount of operating reserves.

Table 5.1 Performance parameters of various conventional technologies for the 2030 ERCOT Case

	Forced outage rate	Planned outage rate	Heat rate (Te/MWh)	O&M variable cost ($/MWh)	Fuel price ($/Mbtu)	Total variable cost ($/MWh)	Ramp rate (MW/h)	Emission rate (tCO2/MWh)
Nuclear	0.04	0.06	9.7	0	0.54	5.2		
Coal old scrubbed	0.06	0.1	10	6.2		28.1	200	0.98
Coal old unscrubbed	0.06	0.1	10	7.1		29.0	200	0.98
Cofired old	0.08	0.09	10.4	6.2	2.19	29.0	140	0.98
Gas steam turbine	0.1	0.12	10.5	5.7		87.9		0.55
CCGT	0.04	0.06	6	3.2		50.2	250	0.32
OCGT	0.03	0.05	9.4	26.2	7.83	99.8		0.5
Biomass	0.09	0.08	13.5	13.2		13.2		
Hydro	0.05	0.02		3.2				

Technology performance parameters of these technologies are shown in Table 5.2, which have been taken from the ReEDS input data used for ERCOT CASE 1. Some of them have particular relevance in system operation. The variable cost of gas technologies is much higher than that of the coal technologies. While nuclear has the lowest variable cost. Gas steam turbine has the highest forced outage rate and planned outage rate, followed by coal technology. Nuclear and CCGT have the same level of outage rates. In contrast, OCGT has the lowest outage rates. In terms of heat rate, gas steam turbine and coal technologies are the most inefficient. CCGT is the most efficient. Nuclear has zero emissions. Not binding by ramp rate, OCGT has the largest flexibility, opposite to nuclear, which is considered inflexible. CCGT is more flexible than coal technology.

Implementation of a carbon price

Since the generating capacity portfolio of ERCOT 2030 has been obtained by ReEDS under a CO2 emission constraint, it is necessary to apply an ad hoc trick to make the results of ReEDS and Memphis to be consistent. Since the Memphis model does not allow imposing a constraint on the total annual CO2 emission, the CO2 cap that was applied in ReEDS is transformed here into a carbon price, which is added to the variable costs of each technology in Memphis. Note that it was inferred in the analytical model that, with a carbon constraint, the optimality conditions representing the competition between each technology are decided by some equivalent total variable costs, which happen to be the sum of the fixed cost, F, and the CO2-internalized variable cost $(V + \lambda_2 e)$. Therefore, within a certain range of values for the dual variable of the carbon constraint λ, the dispatch merit order remains the same until the relative order of some pair of technologies becomes reversed, therefore resulting in a corresponding change in the dispatch merit order.

In order to obtain the merit order that is closest to the one in year 2030 in ERCOT CASE 1, several runs were conducted using different carbon prices. It was found that a carbon price of $40 returns the closest dispatch merit order to the one that was obtained by ReEDS in ERCOT CASE 1. The CO2-internalized variable costs are shown in Table 5.2. Note that compared with Table 5.1, with CO2 price internalized, the variable cost of CCGT is now lower than the variable costs of coal technologies and therefore the dispatch order is flipped.

Table 5.2 Comparison of the original variable cost and CO2-internalized variable cost of various technologies ($/MWh)

	Original variable cost	CO2-internalized variable cost
Nuclear	5.2	5.2
Coal old scrubbed	28.1	67.1
Coal old unscrubbed	29.0	68.0
Cofired old	28.1	67.1
Gas steam turbine	87.9	109.7
CCGT	50.2	63.3
OCGT	99.8	119.4
Biomass	13.2	13.2

Simulation results

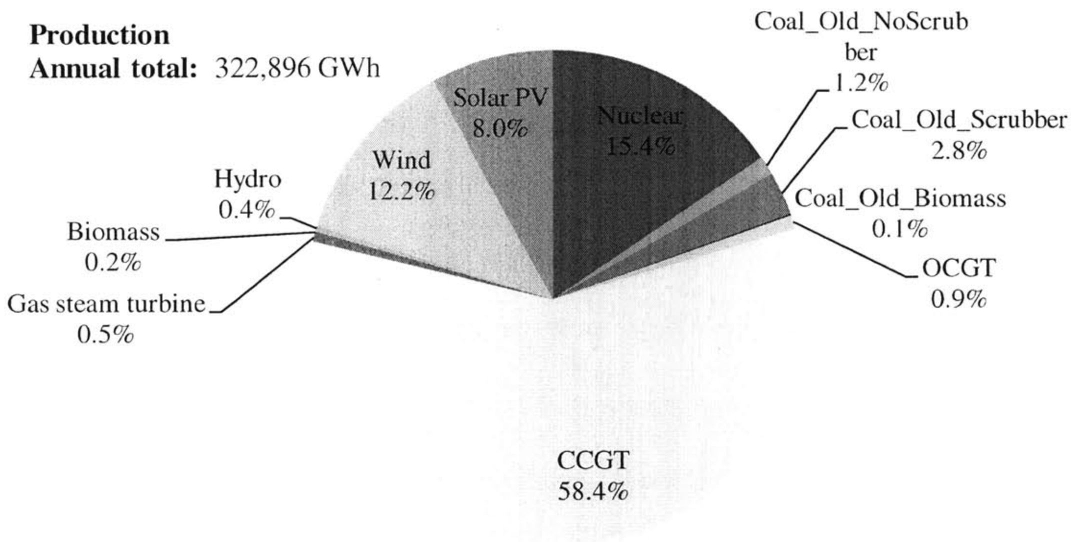


Figure 5-3 Energy production share of the ERCOT 2030 case

Figure 5-3 shows the simulation results of production obtained by Memphis for the ERCOT base case that has been provided by ReEDS and with the modified production costs to make ReEDS and Memphis to be consistent. In this case, wind and solar contribute 12.2% and 8.0% respectively to the total annual energy production. Among conventional technologies, CCGT and nuclear are the two major contributors. CCGT plays the biggest role by contributing 58.4% to the total annual production, followed by a share of 15.4% from nuclear. Coal plays a minor role by producing only 4.1% of the total. OCGT, gas steam turbine and hydro contribute less than 1% each.

Table 5.3 further shows the capacity factor and total operating hours of conventional technologies. Nuclear operates at a capacity factor of 91% and the longest hours of all. It serves a role of base load technology. CCGT operates with a capacity factor of 65%. Coal plants operate much fewer hours, above CCGT in the merit order. OCGT and gas steam turbines operate very limited hours at peak time with very low capacity factors. The low capacity factor of coal plants, because of the carbon emission constraint, implies that a significant amount of coal capacity built earlier may have to be idle in the 2030 scenario, restricted by the carbon policy, as it also happens to the gas steam turbine. Given that OCGT is not constrained by ramp rates, its low capacity factor and few operating hours implies a large amount of extra capacity, besides what is needed to provide tertiary reserves. In the ReEDS model this extra capacity is justified to provide reserve margins for system reliability reasons.

Table 5.3 Operation of conventional technologies in the ERCOT 2030 case

	Production share	Capacity factor	Operating hours (Hr)
Nuclear	15%	91%	7963
Biomass	0.2%	82%	7165
CCGT	58%	65%	5689
Coal_Old_Scrubber	3%	14%	840
Coal_Old_NoScrubber	1%	6%	363
Coal_Old_Biomass	0.1%	9%	50
OCGT	1%	4%	178
Gas steam turbine	0.5%	1%	102
Hydro	0.4%	25%	1118
Wind	12.2%		
Solar	8.0%		

5.2.2 Sensitivity analysis

Sensitivity analyses are performed to quantify the impacts of wind on the short-term system operation. To conduct such analysis, only the level of wind penetration is changed while the rest of the system is kept the same as in the ERCOT 2030 base case. In the base case, the penetration of wind in the total annual production is 12%. In the two sensitivity cases, the hourly wind output is doubled and reduced to half respectively. Therefore in the two cases, wind contributes 24% to the total annual production in the Wind 2.0 case and 6% in the Wind 0.5 case. Because a single multiplier is applied uniformly to the wind output and forecast data at each hour, the pattern of wind becomes stronger in the Wind 2.0 case and flatter in the Wind 0.5 case. Figure 5-4 shows the hourly dispatch results in the base case and in the two sensitivity cases in a representative day.

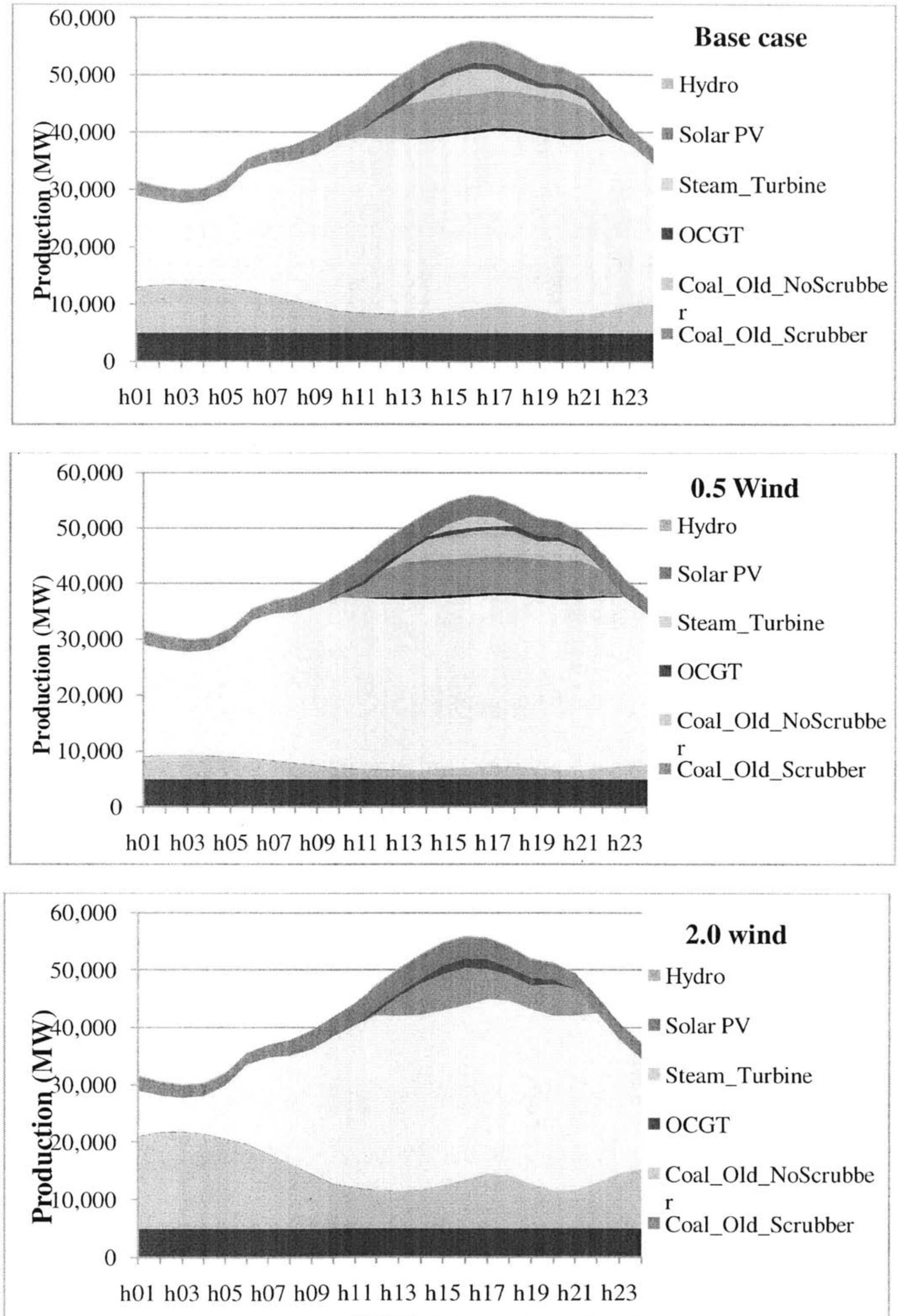


Figure 5-4 Impacts of wind on a one-day dispatch pattern for the ERCOT 2030 case

In the base case, wind is higher from 12 am to around 7 am at a time when load is relatively low, while the opposite happens from 8 am to 23 pm during the peak load. When demand is low, it is mostly supplied by nuclear, wind, CCGT and solar PV. At peak demand, all technologies have to produce. Among the technologies, CCGT operates at 92% of its total nameplate capacity; coal almost only produces at peak time and so it does OCGT. Since OCGT is the only type of technology defined to have quick-start ability in the simulation, it also produces, though very little, at off-peak hours to provide tertiary reserves when secondary reserves are not sufficient to compensate for the wind forecast errors.

In the Wind 2.0 case, when demand is low the additional wind displaces some of the production from CCGT because CCGT is at the margin in the dispatch merit order. When demand is high the additional wind displaces some of the production from coal for the same reason. OCGT is not much affected, because it is either needed at peak demand, or used as tertiary reserves to compensate for errors in the wind forecast. In the Wind 0.5 case, the opposite effects can be seen that either the technology at the margin produces more, or more technologies have to produce to meet the demand. In both cases, nuclear is not affected because it operates as the base load technology.

Table 5.4 summarizes the quantified short-term impacts of wind on the dispatch over the analyzed year for ERCOT. It shows the sensitivity of the annual energy production of conventional technologies to an increment of +1GWh production from wind. Among the conventional technologies, CCGT is the most negatively affected, as it is reduced in 0.85

GWh; coal is the next one affected, with a reduction of 0.12 GWh. Gas steam turbine is affected to a lesser extent, as in the base case it is already operating at a very low capacity factor. However, the impact is positive on OCGT - when wind production is doubled in the Wind 2.0 case, OCGT needs to be operated more to compensate larger wind forecast errors. Conversely, in the Wind 0.5 Case, OCGT is used less.

Table 5.4 Sensitivity of the annual production of various generating technologies to an increment of +1 GWh in the production of wind for the ERCOT case. (Only technologies with change are listed)

Coal_Old_NoScrubber	Coal_Old_Scrubber	OCGT	CCGT	Gas steam turbine
-0.04	-0.08	0.01	-0.85	-0.03

Regarding total system operation cost, sensitivity analyses show that in this case where the capacity portfolio of conventional technologies is unchanged, more wind reduces the total operation costs. Despite that more wind output may be associated with larger wind forecast errors and the corresponding need for additional reserves, the cost savings from wind energy's zero fuel cost outweigh the extra costs caused by use of more operating reserves, when the accuracy in wind forecast is within reasonable limits. But it has to be taken into account that investment costs are not considered in this short-term evaluation.

In addition to cost savings, the environmental benefits are obvious. In the ERCOT 2030 base case, the total CO2 emission is 76 Million tons. In the Wind 2.0 case, the total CO2 emission is 60 million tons, a 20% reduction compared with the base case. On the other hand, in the Wind 0.5 case, the total CO2 emission reaches 84 million tons, an increase of

11% compared with the base case. Table 5.5 shows the change in the total cost and the carbon emissions.

Table 5.5 Total operational cost and CO2 emissions in the three cases for the sensitivity analyses

	Wind 0.5	Basecase	Wind 2.0
Cost (M$)	15,015	13,741	11,229
CO2 emissions (Mton)	84	76	60

5.2.3 Impact of the carbon price

In the base case analyzed above, a carbon price is added to the variable cost of each technology. The carbon price, which could significantly change the generation dispatch pattern, has significant implications for system operators, individual generators and investors. This section compares a scenario that does not consider the cost of carbon emissions with the base case analyzed above. The input is different from the carbon-internalized scenario only in the variable costs, which do not include a carbon price.

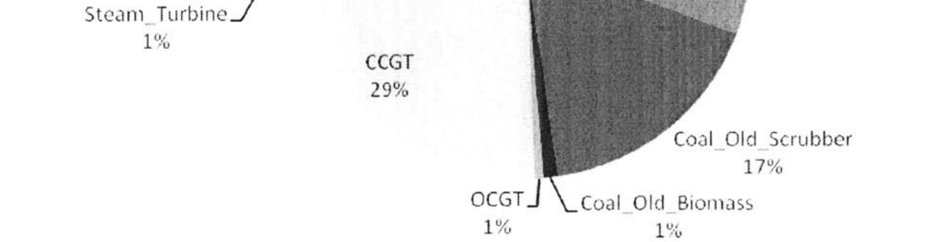


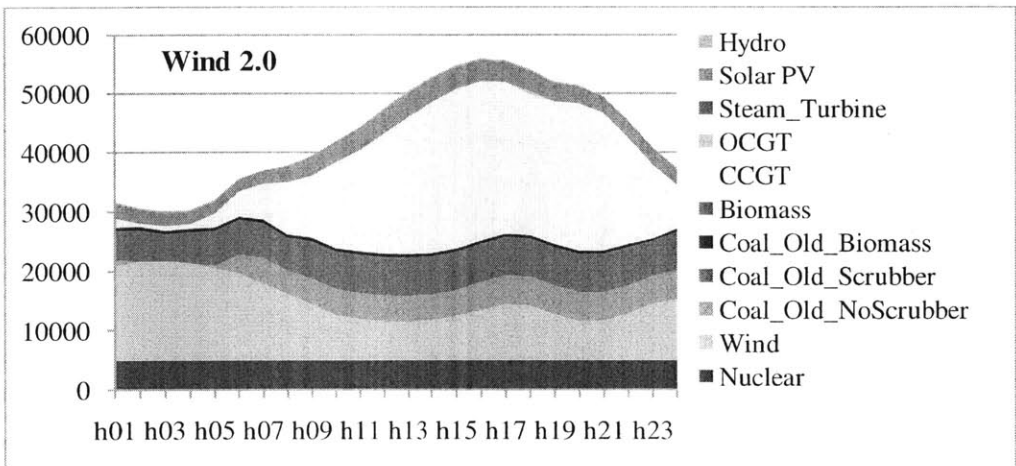
Figure 5-5 Annual production of various technologies in the no-carbon ERCOT case (TWh)

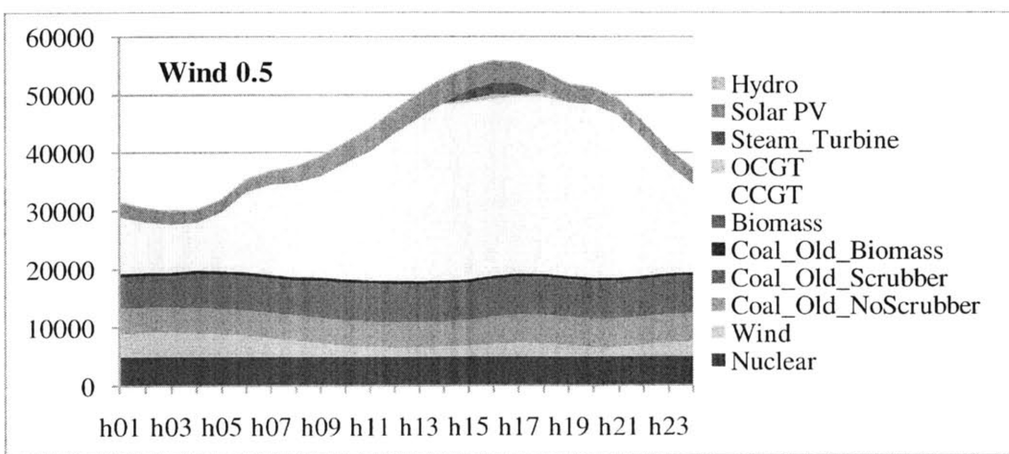
Table 5.6 Impacts of a carbon price on generation dispatch

		No carbon price case		Carbon price case	
	Installed capacity (GW)	Production (GWh)	Capacity factor	Production (TWh)	Capacity factor
Nuclear	6.2	49660	91%	49660	91%
Coal_Old_NoScrubber	7.1	49496	80%	3955	6%
Coal_Old_Scrubber	7.6	55013	83%	9071	14%
Coal_Old_Biomass	0.5	3504	80%	401	9%
OCGT	7.4	1820	3%	2869	4%
CCGT	33.1	94647	33%	188418	65%
Gas steam turbine	14.5	1878	1%	1645	1%
Biomass	0.1	452	52%	519	59%
Hydro	0.5	1256	29%	1185	27%

As can be seen from Table 5.6, for the same ERCOT 2030 system, a carbon price reverses the dispatch merit order of coal and CCGT. Without a carbon price, coal operates at a much higher capacity factor of above 80%, compared with around 10% in the case where a carbon price or constraints are included. The effects on CCGT are opposite in the two cases. Other technologies are not much influenced, as the addition of a carbon price in this case does not change the dispatch merit order of any other two technologies.

Similar wind sensitivity analyses were performed for the no-carbon price case. Figure 5-6 shows the one-day dispatch of the same day as simulated in the carbon-price case. Although the no carbon price base case has a very different dispatch pattern from the carbon price base case, the sensitivity of the system is similar in the two cases. When there is more wind production, CCGT is the most displaced technology; when there is less wind production, CCGT produces more. This is largely because CCGT is always the marginal technology in the dispatch merit order to be displaced first when more wind comes in with zero variable costs. The quantified impacts are shown in Table 5.6, to an increment of +1GWh production from wind, production from CCGT is reduced by 0.73 GWh, production from coal is reduced by 0.25 GWh and production from Gas steam turbine is reduced by 0.03 GWh. Also, similarly to the carbon price case, production from OCGT increases by 0.01GWh.





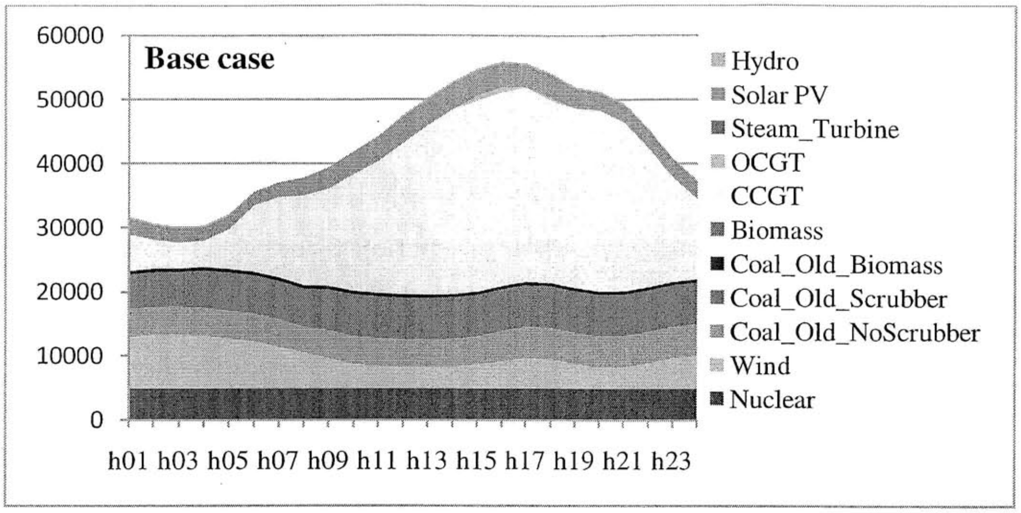


Figure 5-6 Impacts of wind on a one-day dispatch pattern for a no-CO2 price ERCOT 2030 case

Table 5.7 Sensitivity of the annual production of various generating technologies to an increment of +1 GWh in the production of wind for the no-CO2 price ERCOT 2030 case. (Only technologies with change are listed)

Coal_Old_NoScrubber	Coal_Old_Scrubber	OCGT	CCGT	Oil-gas
-0.18	-0.07	0.01	-0.73	-0.03

5.3 The Spanish Case

As introduced earlier in Chapter 2, the presence of large quantities of wind energy can affect the need for operating reserves, because of the increased variability and uncertainty introduced by wind. In order to maintain system security, system operators may adopt a highly conservative attitude toward high safety margins to reduce the risk of the occurrence of non-served energy (Matos & Bessa, 2009). However, both providing additional operating reserves and the occurrence of non-served energy incur more costs. Therefore, this is a question of the trade-off between cost and risk, rather than avoiding all risks at any cost. This section aims to investigate how different operating reserve requirement levels could impact the total operational costs and system operation pattern by looking at the Spanish power system as a case study.

In order to understand how different requirements on operating reserves affect system operation, multiple runs were conducted. In these runs, different levels of operating reserve requirements are specified, with all the other input parameters the same. A least costly case is identified, under the cost assumptions and input parameters and for operating reserves and non-served energy used for this specific Spanish case. This least-cost case is defined here as the Optimal reserve case. For a more detailed discussion on the impacts of operating reserve levels on aspects of system operation other than costs, two other cases are selected from the runs that have been conducted to be presented here for comparison. One has higher specified reserve requirements than the optimal case, here referred to as Higher reserve case; the other has lower specified reserve requirement than the optimal case, here referred to as the Lower reserve case.

5.3.1 Spain 2016 capacity portfolio

Figure 5-7 shows the estimated installed capacity for 2016 of various generating technologies in the Spain case. Among conventional generating technologies, CCGT has the largest installed capacity of 30,560 MW. Hydro, nuclear and coal each have installed capacity of 7,500 MW, 7,250 MW and 8,526 MW. Pumped hydro and OCGT have the least installed capacity, 3,750 MW and 3,200 MW respectively. The total annual demand in this case is 351,245 GWh. The total annual output from distributed generation from renewable generation sources other than wind is 62,500 GWh. The total annual wind output is 62,007 GWh. Therefore, generation from conventional technologies has to meet the rest of the demand that cannot be met by wind and distributed generation.

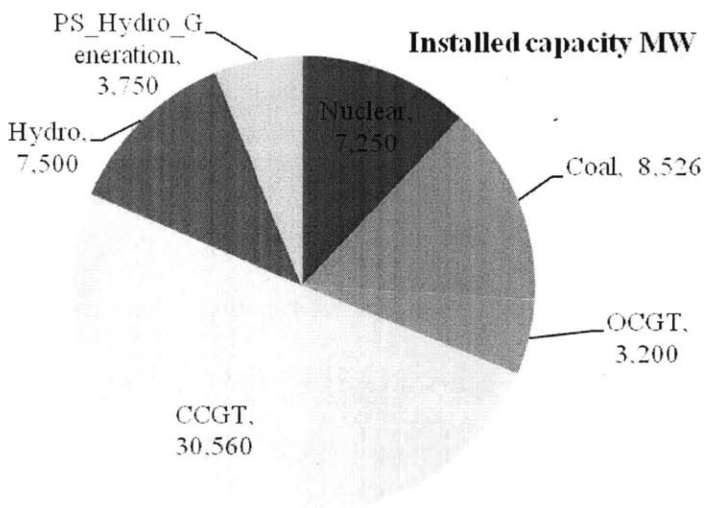


Figure 5-7 Generation capacity portfolio of the Spanish Case for 2016 (MW)

5.3.2 Optimal reserve case

<u>Representation of operating reserves in Memphis</u>

In Memphis, the representation of operating reserves includes both the requirement for secondary (spinning) reserves and the actual reserves provided by various technologies. As introduced earlier in Chapter 3, in the Memphis modeling the secondary reserves are provided by units that are not operating at their maximum capacity. The amount of secondary reserves each of these units can provide is the difference between the maximum capacity and the actual production level beyond its technical minimum. Since during the optimization for unit-commitment, some units are already planned not to operate at their maximum capacities limited by factors such as ramp rates, a proportion of these capacities automatically provide secondary reserves. In addition, a certain level of secondary reserves can be explicitly required, regardless of how many reserves are already planned through the unit-commitment process. If such reserve requirements are higher than what will otherwise be available without the requirements, then different results would be obtained when the requirements are imposed. Otherwise, such requirements are not binding. Not meeting the secondary reserve requirements results in a penalty ($/MW) that can be specified exogenously for each system being modeled. In addition to secondary reserves, Memphis also represents tertiary reserves, in a somewhat different way. Which units can provide tertiary reserves have to be specified as inputs, and only these units, and all these units, are used as tertiary reserves if they are not producing.

Optimal reserve case

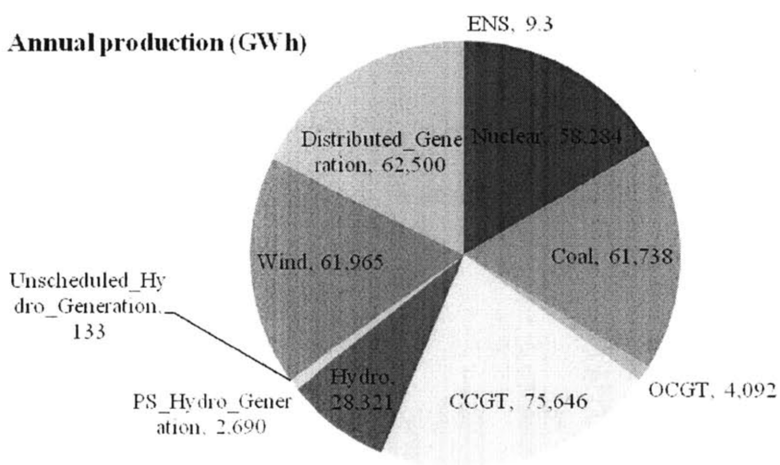


Figure 5-8 Annual production from various technologies in the Spanish Optimal case for 2016

In the Optimal case, the dispatch results come out as nuclear contributing 16%, coal 17%, CCGT 21%, OCGT 1%, hydro 8% and pumped hydro 1% to the total energy production, as Figure 5-8 shows.

5.3.3 Impacts of operating reserve requirements

Table 5.8 Three different reserve requirement cases and total system costs

	Lower reserve case	Optimal reserve case	Higher reserve case
Reserve requirement (MW)	3139	3210	3351
Cost (Million $)	9770	9768	9773

Table 5.8 shows the different operating reserve requirements and the associated total operation costs in the three cases. In the Optimal case, an amount of 3,210 MW spinning reserves are required and the total annual operation cost is $9,768M. This 3,210 MW is meant to cover the amount needed in case of the concurrence of 0.3 of the largest wind forecast error and a failure of the biggest unit in the system. In the Lower reserve case, 3,139 MW reserves are required, which equal the sum of 0.29 of the largest wind forecast error and the maximum output of the largest unit. In this case, the total annual system operational cost is $9,770M. In the Higher reserve case, 3,351 MW of operating reserves are required, which equal the sum of 0.32 of the largest wind forecast error and the maximum output of the largest unit. The total annual system cost is $9,773 M in this case.

Table 5.9 Production from various generating technologies in cases with different reserve levels (GWh)

	Lower reserve case	Optimal reserve case	Higher reserve case
Nuclear	58284	58284	58284
Coal	61799	61738	61671
OCGT	4109	4092	4012
CCGT	75577	75646	75789
Hydro	28318	28321	28329
PS_Hydro_Generation	2662	2690	2695
Unscheduled_Hydro_Generation	142	133	116
Wind	61968	61965	61964
Distributed_Generation	62500	62500	62500
ENS	8.7	9.3	8.8
Demand	351245	351245	351245
PS_Hydro_Consumption	4122	4132	4123

As shown in Table 5.9, different requirements on spinning reserves result in different dispatch results. Such impacts do not appear on nuclear, but on all the other technologies. In this Spanish case, the higher the spinning reserve requirements are, the more OCGT, coal and unscheduled hydro produce, and the less CCGT, scheduled hydro and pumped hydro produce. Among the three cases, the non-served energy in the Optimal Case is 9.3 GWh, which is slightly more than the other two cases. Sensitivities are computed to show how production from each technology changes responding to the change in the reserve requirements. Figure 5-9 shows the average change in the production from various technologies when +1 MW more spinning reserve is required for the system. Such impacts are -1.3 GWh on coal, -0.8 GWh on OCGT, -0.2 on unscheduled hydro, 2.0 GWh on CCGT, 0.1 GWh on scheduled hydro, and 0.4 on pumped hydro.

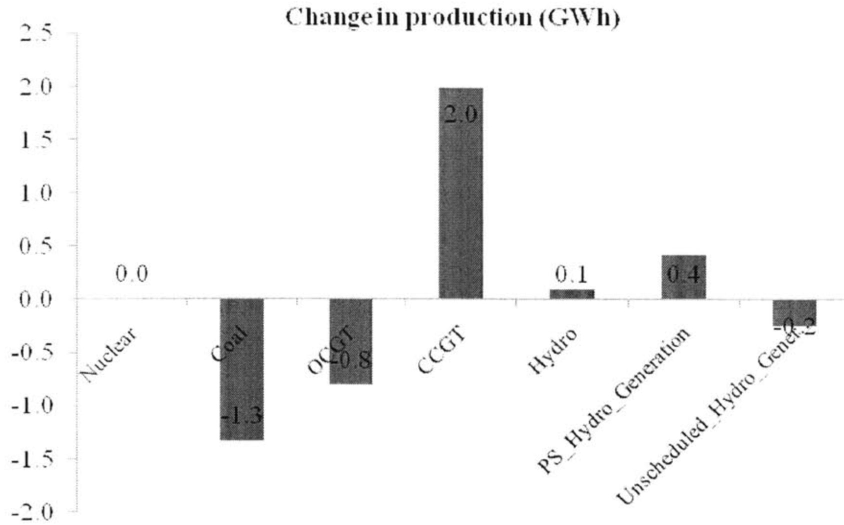


Figure 5-9 Change of production from various technologies per +1MW change of spinning reserve requirement (GWh/MW)

The spinning reserve requirement is affecting both the unit commitment and the real time dispatch, depending on the occurrence of wind forecast errors and contingent events. At the unit-commitment stage, higher reserve requirements may imply that additional units have to be operating, or some units have to produce less, to provide the additional reserves required. At the real time dispatch stage, if spinning reserves are not able to cover the sum of the wind forecast errors and contingencies, either quick start units, which is OCGT in this case, have to be started, or non-served energy happens, depending on the tradeoff between the costs of starting up additional units and the costs of the occurrence of non-served energy

Table 5.10 The total unit-commitment of various technologies in the three cases (GWh)

	Lower reserve case	Optimal reserve case	Higher reserve case
Nuclear	58773	58773	58773
Coal	63101	63038	62960

OCGT	4215	4220	4193
CCGT	76010	76084	76208
Hydro	24551	24551	24592
PS_Hydro_Generation	1275	1276	1221
Unscheduled_Hydro_Generation	159	152	131
Wind	61963	61951	61952
Distributed_Generation	62500	62500	62500
ENS	0	0	0

Comparing these three cases, during the unit commitment stage, when more spinning reserves are required for every hour over the year, less coal production is planned. Two factors are contributing to this: compared with other technologies, the technical minimum of coal is low, while the difference between the nameplate capacity and its technical minimum, which is the available capacity to provide spinning reserves, is relatively high. Therefore, less production is planned from coal and this leaves more capacity available to provide reserves. As less production is expected from coal, other less-costly technologies would be needed to produce more. Therefore, more production from CCGT and hydro are planned. Such increase in the planned production from CCGT could further displace production from OCGT and pumped hydro, as can be seen from the Table 5.10. In contrast, when less spinning reserves are required, in case of a situation where spinning reserves are not able to cover the sum of wind forecast errors and contingencies, either unscheduled hydro operates, or OCGT is started up, or non served energy occurs. Such impacts can be observed from comparing Table 5.10 and Table 5.11. In the Less reserve case, the difference between the unit commitment and actual production of OCGT, is more than that in the Optimal case, because of the need to compensate at times where secondary reserves are insufficient. In all three cases, nuclear, both at unit commitment stage and at real time, stays the same, because of its base load role in the dispatch.

In this specific case, an optimal level of spinning reserve of 3210 MW for each hour has been identified to have the least cost. This is the result of the tradeoff between the costs to provide spinning reserves, the costs to produce energy, the cost of not meeting the demand, the cost of unscheduled hydro, the costs to start up and shut down units, etc.

The "optimal reserve level" is case specific. Similar runs have also been done with other sample wind output and forecasts data, the annual total of which is the same as the analyzed case, for the same system. Different optimal reserve requirement level can be obtained for each specific case, depending on the largest wind forecast error and the combined occurrence of wind forecast errors and contingencies.

5.4 Summary

This chapter has analyzed the hour by hour system operation in a projected future scenario with the presence of large quantities of wind energy. Two power systems, the ERCOT system and the Spanish power system, are used as case studies to analyze a) the detailed operation of a power system with a significant presence of wind energy, and b) under the same conditions, the influences of different operating reserve levels on system operation.

A strong penetration of wind energy always displaces the technology at the margin. However which technology is most affected is decided by various factors. In the ERCOT case, the CO2 price in the analyzed scenario changes the relative dispatch order of coal and gas technologies. However, regardless of whether the CO2 price is in place, under the assumed conditions, CCGT is most of the time the marginal technology in the dispatch order and the biggest contributor to the total energy production, thus an increment in energy production from wind reduces mostly production from CCGT. It should be noted that the load profile is also a factor in deciding the most affected technology.

An "optimal" reserve level depends on a number of factors and is case specific. In a power system where large quantities of wind energy are present, the operating reserve requirement affects both the unit commitment and real time dispatch of various generating sources. The optimal level of operating reserve level can only be identified in relative terms, which depends on the relativity between the cost of a failure to provide energy and the cost of providing reserves. It is also a decision for generation technologies to make between providing operating reserves and producing energy. Therefore, an appropriate mechanism should also be in place to compensate generation technologies that are not making profit from production to provide sufficient operating reserves.

CHAPTER 6. BENCHMARK OF ReEDS WITH MEMPHIS

6.1 Introduction

In previous chapters, the impacts of wind energy on the long-term and short-term are analyzed separately using two different types of models. However, these analyses are linked through the ERCOT 2030 cases. As introduced earlier, in ERCOT CASE 1 for the long term, both the installed capacity and the annual total productions for all technologies, are calculated by the ReEDS model as outputs. In the ERCOT 2030 case for the short-term analysis, the installed capacities of various technologies and the parameters for these technologies are used as inputs in Memphis to obtain the hourly unit commitment and generation dispatch simulation. The link between the two models provides an opportunity to compare the results obtained by both models. In particular, given that the Memphis model is more realistic in simulating system operation, it can be used as a benchmark to assess the accuracy of ReEDS in representing the power system at the operational level.

Two cases are studied in this chapter. One is the ERCOT 2030 CO2 CASE, which has already been presented in Chapter 5, with the installed capacity portfolio obtained from ERCOT CASE 1 in Chapter 4. The other is the ERCOT 2030 NO CO2 CASE, with the installed capacity portfolio obtained from ERCOT CASE 2 in Chapter 4. The energy production over the considered year from each technology is benchmarked primarily between the two models. In addition, the representation of operating reserves is also compared.

6.2 Benchmark of ReEDS with Memphis

6.2.1 ERCOT 2030 CO2 CASE

Energy production

Table 6.1 shows the annual energy production from each technology obtained by Memphis and ReEDS respectively. The input data and model settings are introduced in Chapter 4 and 5.

Table 6.1 Annual production for the ERCOT 2030 CO2 CASE in Memphis and ReEDS

	Installed capacity (GW)	Production (TWh)		Difference (ReEDS – Memphis)	
		Memphis	ReEDS	(TWh)	(% of total demand)
Nuclear	6.2	49.7	49.3	-0.4	-0.1%
Biomass	0.1	0.5	0.5	0	0
CCGT	33.1	188.4	187.3	-1.2	-0.4%
Coal_Old_NoScrubber	7.1	4.0	6.7	2.8	0.9%
Coal_Old_Scrubber	7.6	9.1	9.8	0.8	0.2%
Coal_Old_Biomass	0.5	0.4	1.0	0.6	0.2%
OCGT	7.4	2.9	1.7	-1.2	-0.4%
Steam_Turbine	14.5	1.6	0.4	-1.2	-0.4%
Hydro	0.5	1.2	1.0	-0.2	-0.1%
Wind	19.7	39.5	39.5	0	0
Solar PV	12.4	25.7	25.7	0	0
Total annual demand		322.9			

In order to achieve consistency when examining the impact of wind energy on the dispatch of conventional generating technologies, before running Memphis, the total annual production of wind and solar PV have been pre-scaled to the level equal to the annual production from ReEDS as inputs. The comparative analysis shows (see Table 6.1) that for conventional technologies the results obtained by ReEDS for nuclear and CCGT, the biggest two contributors to the total energy production, are only slightly less than those obtained by Memphis. The production on coal, the intermediate technologies, is larger in ReEDS than in Memphis in both absolute and relative terms. Production from peaking technologies, which are OCGT and gas steam-turbine, are less in ReEDS than in Memphis, a small absolute difference but large in relative terms with the total production with these technologies.

Operating hours of various technologies

The total operating hours of each technology from both models are shown in table 6.2. In ReEDS, all technologies operate significantly more hours than in Memphis. For example, in ReEDS, nuclear operates non-stop over the year, as is the same as CCGT. While in Memphis, nuclear operates 7963 hours and CCGT only operates 5689 hours. The discrepancy is even larger for intermediate technologies and peaking technologies. The three different types of coal technology operate between 50 hours to 840 hours in Memphis, which in ReEDS are modeled uniformly to be 3672 hours. Peaking technologies OCGT and gas steam turbine operate 612 hours and 2208 hours respectively in ReEDS, in contrast to 178 and 102 hours in the Memphis simulation results.

Table 6.2 Operating time of various technologies in Memphis and ReEDS (hours)

	Memphis	ReEDS
Nuclear	7963	8760

Biomass	7156	8760
CCGT	5689	8760
Coal_Old_NoScrubber	363	3672
Coal_Old_Scrubber	840	3672
Coal_Old_Biomass	50	3672
OCGT	178	612
Gas_Steam_Turbine	102	2208
Hydro	1118	8333

As introduced earlier in Chapter 3, the 8760 hours in a year are disaggregated into 17 time periods to approximate the load duration curve in ReEDS. H17 corresponds to the "super peak" time period defined in the ReEDS, which covers 40 hours. H3 is the second highest demand interval that covers 328 hours. Table 6.3 compares the production from each technology in ReEDS for the period of H17 and H3 (totaling 368 hours), with the production from each technology in the 368 hours of the highest load in Memphis. For nuclear, CCGT and OCGT, the production in the highest 368 hours in ReEDS is higher than that in Memphis; for coal, however, the production in the highest 368 hours is lower in ReEDS than that in Memphis.

Table 6.3 Comparison of production from various technologies in the 368 highest load hours in ReEDS and in Memphis for the ERCOT CO2 2030 CASE

	Average production over the highest 368 hours of load (H17+H3) (MW)		Production over the highest 368 hours of load (H3+H17) of each technology as a fraction of its production over a year (MW)	
	Memphis	ReEDS	Memphis	ReEDS
Nuclear	5463	5987	4%	4%
CCGT	29472	30989	6%	5%
Coal_Old_NoScrubber	5559	4884	52%	24%
Coal_Old_Scrubber	6317	6113	26%	20%
Coal_Old_Biomass	179	393	16%	13%
OCGT	1870	2895	24%	56%
Steam_Turbine	3860	882	86%	70%
Biomass	63	66	4%	4%
Hydro	225	457	7%	15%

CO2 emissions

The total annual CO2 emissions obtained by ReEDS are 78 million tons, versus 76 million tons obtained by Memphis. The higher CO2 emissions in ReEDS result from the larger production from coal technologies.

Operating reserves

In this case, operating reserves in ReEDS total 7.29 GW, among which 5.39 GW are spinning reserves (or secondary reserves) and 1.9 GW are quick start reserves (or tertiary reserves). These reserves are required in case of frequency regulation, contingency and wind forecast errors. In Memphis, all OCGT units are considered to be able to be connected at real time. Therefore, all the OCGT capacity that does not produce can be used as tertiary reserves, which is 4.71 GW. To conform to the specified requirements to cover 3% of demand, 17% of the largest hourly wind output and the potential failure of the largest unit, secondary reserves are 4.75 GW in Memphis. In addition, Memphis further computes the amount of reserves that are actually used at real time to produce, which in this case include 1.0 GW secondary reserves and 0.25 GW tertiary reserves.

Table 6.4 Operating reserves for ERCOT 2030 CO2 case in Memphis and ReEDS at peak demand (GW)

<table>
<tr><td rowspan="4">ReEDS</td><td>Reserves for wind forecast error</td><td>Reserves for contingency</td><td>Reserves for frequency regulation</td><td>Total reserves</td></tr>
<tr><td>2</td><td>4.23</td><td>1.06</td><td rowspan="3">7.29</td></tr>
<tr><td colspan="2">Secondary (spinning)</td><td>Tertiary (Quick-start)</td></tr>
<tr><td colspan="2">5.39</td><td>1.90</td></tr>
<tr><td rowspan="6">Memphis</td><td>Reserves for wind forecast error</td><td>Reserves for contingency</td><td>Reserves for demand variation</td><td>Total reserves</td></tr>
<tr><td>1.79</td><td>1</td><td>1.96</td><td rowspan="5">9.46</td></tr>
<tr><td colspan="2">Secondary (spinning)</td><td>Tertiary (Quick-start)</td></tr>
<tr><td colspan="2">4.75</td><td>4.71</td></tr>
<tr><td colspan="2">Actual use of secondary reserve</td><td>Actual use of tertiary reserve</td></tr>
<tr><td colspan="2">1.0</td><td>0.25</td></tr>
</table>

Discussion on the benchmarking of ReEDS with Memphis

Considering the comparisons between the Memphis and ReEDS calculations of the total production, production at high demand period, and total operating hours of each technology, some conclusions can be drawn:

If Memphis is considered the benchmark, it can be concluded that, from the evidence that has been presented, Nuclear and CCGT are well represented in ReEDS. The values for OCGT, gas steam turbine and coal are less accurate, but they are minor contributors to the overall production.

Nuclear, the technology at the bottom of the dispatch merit order, is almost the same in terms of both production and operating hours in ReEDS when compared to Memphis. This is because in ReEDS, nuclear is assumed to be a must-run technology with very high capacity factor. In the Memphis simulation, with the low variable costs and zero CO2 emission, nuclear is always dispatched first and plays the role of a baseload technology. The production of nuclear obtained by ReEDS is slightly less than that obtained by Memphis and two factors may have resulted in this difference: first, a stochastic approach is taken to represent the forced outage of units in Memphis. While in ReEDS, a deterministic approach is taken by applying the multiplier (1- minus forced outage rate – planned outage rate) to the maximum capacity, when calculating the available capacity, resulting in smaller availability of nuclear in ReEDS than in Memphis. Second, in ReEDS, ERCOT is disaggregated into 8 power balancing areas. Thus transmission capacity between these regions could have an impact on the delivery of power into other regions.

Despite the almost same levels of total energy production, CCGT operates many more hours in ReEDS than in Memphis. Such differences are more significant for technologies at or close to the margin of the dispatch merit order. In ReEDS, compared with in

Memphis, OCGT operates more time over the year and produces more at peaking hours. However, in ReEDS, the total production of OCGT is less than that in Memphis. Combined factors result in the differences discussed above because of the different structures of the two models. The following aspects could have contributed largely to these discrepancies:

- The representation of load

In Memphis, historical hourly load data is scaled as input, therefore following hourly chronology that is close to reality. In contrast, in ReEDS, a simplified load duration curve is used[6]. Such a load duration curve is not an exact representation of the order of 8760 hours of a year; rather, 17 time segments covering different numbers of hours are used to approximate the load duration curve. Although the 17 time periods do capture some distinct seasonal and diurnal differences, the variation of load is largely missing in this simplified treatment of load in ReEDS. This explains why several technologies are operating much more time in ReEDS than in Memphis.

- The representation of wind

Similar to load, explicit hourly wind output and forecast data from historical data are scaled and used as input in Memphis. Differently, in ReEDS, wind is represented using statistically methods to calculate the capacity credit, operating reserve needed for wind forecast errors and wind surplus for each time period.

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[6] See Chapter 3 for the discussion on load duration curve.

Moreover, the representations of wind and load in Memphis also take into consideration the correlation between wind and load. As discussed in Chapter 2, this correlation is case specific and could be significant in some circumstances.

- Unit commitment and real time dispatch

In Memphis, the day-ahead unit commitment process is separated from the real time dispatch process. With these two stages separated, technical constraints, such as the ramp rate and technical minimum, as well as economic constraints, such as the start-up and shut-down costs, are incorporated in the decision making process for system operation. The two-phase process also allows the correction of wind forecast error. In contrast, ReEDS has more limitations in representing these details.

- Representation of operating reserves

In Memphis, a certain amount of secondary reserves is required. In the ERCOT 2030 case, the required amount of secondary reserve equals to the sum of 17% of largest wind forecast error occurring during the year, 3% of the corresponding demand and the maximum output of the largest unit. These reserves are assumed to be provided by spinning generating units that are not producing at their maximum output level. If secondary reserves are not enough to correct wind forecast errors, units that have quick-start ability, in this case OCGT, can be started up at real time to produce. These units are basically tertiary reserves in the Memphis simulation. Therefore, when calculating secondary reserves, Memphis optimizes costs at the generating unit level and makes discrete decisions of which units to start up and produce. In addition, it is also able to represent the actual use of both secondary and tertiary reserves when wind forecast errors and contingencies take place.

In ReEDS, a certain level of operating reserves is required for contingency, frequency regulation and wind forecast errors. Contingency reserves requirement is defined as 6% of load; frequency regulation is defined as 1.5% of load; the wind forecasts for the next hour are assumed to be the same as the actual wind output for the current hour. Thus the wind forecast error for each hour is the difference between the output of the considered hour and the previous hour. The operating reserves can be provided by both spinning units (secondary reserves) and units that have quick-start ability (tertiary reserves). However, quick start units cannot provide more than 50% of the reserves for wind forecast errors. Unlike Memphis, ReEDS does not consider the use of reserves at the dispatch stage. In particular, as OCGT is the only tertiary reserve provider in Memphis, not only is it used at peak time to meet the high demand, but also is used all along the simulation year as tertiary reserve to compensate the production gap caused by wind forecast error. In contrast, the production of OCGT in ReEDS is only decided by the peak demand and the use of reserves is not represented.

Comparing the operating reserves calculated by the two models, in these two specific runs, ReEDS results in more secondary reserves than Memphis does. However, because all available OCGT capacities are defined as tertiary reserves in Memphis, and these capacities may be built by ReEDS for reliability purposes, it is difficult to compare directly tertiary reserves in the two models. In this case, the actual use of secondary and tertiary reserves to produce is 1.0 GW and 0.25 GW in Memphis, considerably smaller than the requirements. Nevertheless, under some extreme situation where several units fail together, or combined with large wind forecast errors, how many reserves should be required depend on the targeted system security level and the costs of not meeting the demand.

6.2.2 ERCOT 2030 NO CO2 CASE

A second case, the ERCOT 2030 NO CO2 CASE, is conducted with Memphis to benchmark the results for the year 2030 in the ERCOT CASE 2[7] performed by ReEDS. Similar approaches are taken using the installed capacity obtained by ReEDS as inputs in Memphis. In this case, because no CO2 policy is put in place, various technologies are competing solely at their variable costs, regardless of their CO2 emission levels. Therefore, the dispatch order in this case is different from the previous case. Similar to the ERCOT CO2 case, comparisons on energy production, operating hours and operating reserve requirements and usage are conducted between the results obtained from the two models. This case will be discussed in less detail as the underlying reasoning is the same as in the first case.

[7] See Chapter 4 for the detailed description of the ERCOT CASE 2.

Production of various technologies

Table 6.5 Comparison of productions from various technologies in the 368 highest load hours in ReEDS and in Memphis for the ERCOT 2030 NO CO2 CASE

	Installed capacity (GW)	Generation (TWh)		Difference between ReEDS and Memphis	
		Memphis	ReEDS	Absolute value (TWh)	As a percentage of load (%)
Nuclear	4.9	38.7	36.2	-2.5	-0.8%
Coal_Old_NoScrubber	8.1	52.8	52.9	0.2	0.1%
Coal_Old_Scrubber	7.1	58.9	60.0	1.1	0.3%
CCGT	27.9	133.9	134.0	0.0	0.0%
OCGT	2.7	4.9	4.5	-0.4	-0.1%
Steam_Turbine	14.6	10.3	12.8	2.5	0.8%
Hydro	0.5	1.5	1.0	-0.5	-0.1%
Wind	12.1	16.1	16.1		
Solar PV	2.7	5.7	5.7		
Total annual demand		323.3			

Operating hours of various technologies

Table 6.6 Total operating hours of various technology in Memphis and ReEDS (hr)

	Memphis	**ReEDS**
Nuclear	7963	8760
Coal_Old_NoScrubber	4801	8760
Coal_Old_Scrubber	5448	8760
OCGT	250	1020
CCGT	4025	8760
Steam_Turbine	637	3672
Hydro	1410	8333

In this No CO2 Policy case, with its low variable costs, coal is producing significantly more than in the previous case. Productions from baseload and intermediate technologies in ReEDS are well represented compared with Memphis. Discrepancies in the production of peaking technologies are relatively larger, due to the same reasons discussed in the previous case. Regarding operation hours, nuclear, coal and CCGT are assumed in ReEDS to operate all over the year as the base load technologies. Similar to the ERCOT 2030 CO2 CASE, all technologies operate much longer time in ReEDS than in Memphis, because of the simplified way to present load duration curve through 17 time segments in ReEDS as has been discussed in the CO2 case.

Reserve requirement and usage

Table 6.7 Operating reserves for ERCOT 2030 CO2 case in Memphis and ReEDS at peak demand (GW)

<table>
<tr><td rowspan="4">ReEDS</td><td>Reserves for wind forecast error</td><td>Reserves for contingency</td><td>Reserves for frequency regulation</td><td>Total reserves</td></tr>
<tr><td>0.69</td><td>4.23</td><td>1.06</td><td rowspan="3">5.98</td></tr>
<tr><td colspan="2">Secondary (spinning)</td><td>Tertiary (Quick-start)</td></tr>
<tr><td colspan="2">4.69</td><td>1.29</td></tr>
<tr><td rowspan="6">Memphis</td><td>Reserves for wind forecast error</td><td>Reserves for contingency</td><td>Reserves for demand variation</td><td>Total reserves</td></tr>
<tr><td>0.73</td><td>1.0</td><td>1.96</td><td rowspan="5">6.4</td></tr>
<tr><td colspan="2">Secondary (spinning)</td><td>Tertiary (Quick-start)</td></tr>
<tr><td colspan="2">3.7</td><td>2.7</td></tr>
<tr><td colspan="2">Actual use of secondary reserve</td><td>Actual use of tertiary reserve</td></tr>
<tr><td colspan="2">0.84</td><td>0.71</td></tr>
</table>

In this case, the requirements in ReEDS and Memphis for spinning reserves are very close. Similar to the CO2 Case, more tertiary reserves requirements are defined in Memphis than in ReEDS. Compared with the CO2 Case, in this case, both ReEDS and

Memphis have lower secondary and tertiary reserve requirements. This is because a certain amount from these reserves is required to cover wind forecast errors, which are positively correlated to the magnitude of hourly wind output. Likewise, the actual use of reserves to produce is also smaller in this No CO2 Case compared with the CO2 Case.

6.3 Conclusion

This chapter benchmarks ReEDS with Memphis by analyzing two specific cases: ERCOT CO2 2030 Case and ERCOT NO CO2 2030 Case. In both cases, ReEDS has fair presentations of the annual production from baseload and intermediate technologies. The representation of peaking technologies and reserve requirements is less accurate in relative terms but does not have significant economic impacts on system operation. However, the impact on the need for investment in peaking technologies, due to reliability and system reserve requirements, can be substantial.

CHAPTER 7. SUMMARY AND CONCLUSIONS

7.1 Thesis Summary

The fast growth of wind energy on a global scale has been driven by various economic, political and environmental factors. As this trend is expected to continue and the wind penetration level increases, new challenges are also expected to be faced by electric power systems, where less experience has been accumulated about wind energy, compared with conventional generation technologies. Because of the additional variability and uncertainty wind energy could bring, the understanding of how these attributes of wind energy would affect the power system is of great significance, both in the short term and in the long term. On one hand, this understanding would facilitate the well adaptation of operation rules to the presence of large quantities of wind energy, so that system security and reliability can be guaranteed. On the other hand, it provides useful insights for policy makers to orient investments in the power system toward the intended outcomes. Within this context, this thesis explores the impacts of wind energy on the power system under some major carbon policy scenarios. Three models are used as the primary tools in this thesis.

The ReEDS model is used for the long term analysis to project trajectories of generation capacity mix both with and without a CO2 cap policy, for the ERCOT case and the contiguous US case respectively. Also backed by the analytical model developed in this thesis, the analysis focuses on the interactions between the growth of wind energy and the rest of the power system. Sensitivity analysis is further performed to investigate the response of a power system to reach different levels of wind penetration in the future under the same demand trajectory and CO2 policies.

The Memphis model is used for the short-term analysis of a future "snapshot" year taken from the trajectory obtained by the ReEDS model, where the system sees a significant amount of wind penetration and a well adapted power system. This part of the thesis looks at the hour-by-hour system operation in detail and analyzes the sensitivity of the system to the change of the wind penetration, with the capacity of other technologies fixed. In addition, this part of the thesis also explores, in the event of large quantities of wind energy, how the power system responds to different levels of operating reserve requirements by looking at the case of the Spanish power system. Compared with the long-term analysis, the short-term analysis does not look at investment decisions; however, it looks at system operation in much more detail.

Because of the capability of the Memphis model to simulate the power system operating in a more realistic manner, it is further used as a benchmark to evaluate the representation of system operation in the ReEDS model.

All the major conclusions from the above application of the three models and the analysis of the outcomes for the long-term and short-term impacts of wind energy are summarized below.

7.2 Major Conclusions

About the long term impacts of large quantities of wind energy on the electric power system:

- Wind energy is less likely to develop in a world where CO2 emissions are not restricted. Under the CO2 policy assumptions used in the ERCOT and US reference cases, the current system could experience a significant transition to one that is sufficiently reliable to accommodate a strong penetration of wind energy. Very different generation patterns, compared with the current ones, could also appear in future power systems with large quantities of wind energy.
- If a CO2 emission limit is imposed, wind energy, backed by sufficient flexible generation technologies, in many cases open cycle gas turbines, can compete successfully against the expansion of nuclear energy in the analyzed case. However, in different situations, which technology could be most affected depends on multiple factors, including both the conditions of the specific system as well as the carbon policy implemented. Therefore, it is important for regulators and policy makers to be aware of these impacts when designing energy policy strategies such as quotas for renewables, carbon levies or incentives to guide market behaviors.
- In the strong presence of wind energy, to guarantee system reliability, an adequate amount of flexible capacity is needed, mostly to provide firm capacity margin, which however, may produce very little electricity on a daily or annual

basis. A sound policy scheme is therefore necessary to incentivize adequate investment in such technologies in the future and have them be financially viable even at very low capacity factors.

About the short-term impacts of large quantities of wind energy on the electric power system:

- In a future scenario where a large penetration of wind energy takes place, in the short term, an increment of wind energy displaces production from technology that is mostly at the margin of the dispatch order. In the cases analyzed in this thesis, combined cycle natural gas is the most affected technology. The carbon price may flip the dispatch order, therefore resulting in the increased cycling times of some technologies and reduce those of another technologies. However, in absolute value, a carbon price does not necessarily change the technology mostly affected by an increase in wind penetration in the short term.
- In a power system where large quantities of wind energy are present, the operating reserve requirement affects both the unit commitment and the real time dispatch of various generating sources. The optimal level of operating reserve level can only be evaluated in relative terms in that it is case specific and depends on the tradeoff between the cost of a failure to provide energy and the cost of providing reserves. It is also a decision for generation technologies to make between providing operating reserves and producing energy. Therefore, a

mechanism should also be in place to incentivize generators to be available and idle so that the sufficient operating reserves can be provided.

About the benchmarking of ReEDS with Memphis:

- As a long-term capacity expansion model, the ReEDS model also has fair representations of the annual production from base load and intermediate technologies.
- The representation of the operation of peaking technologies and reserve requirements in ReEDS are less accurate in relative terms, but does not have significant economic impacts on system operation. However, the impact on the representation of the need for investment in peaking technologies, due to reliability and system reserve requirements, can be substantial.

7.3 Future Work

In light of the experience and lessons learnt from this thesis, future work to extend the discussions made in this thesis includes the following aspects:

First, for the long-term analysis, only the CO2 cap policy scenario is considered and analyzed in this thesis. However, in the real world, alternative policy measures could be adopted, such as a CO2 price, or a renewable portfolio standard. Under different policy schemes, the impacts of large quantities of wind energy could be different. Therefore, other policy scenarios would provide useful insights for policy makers when adopting the most appropriate policy measure for a specific policy goal.

Second, for the short-term analysis, because of the specificity, different power systems with different installed capacity mix should also be analyzed to evaluate how system responds to different levels of operating reserve requirements. The impact of the accuracy of wind forecast errors should also be studied in the presence of large amounts of wind energy.

Third, for the short term analysis, because of the limitation of the model configuration, the CO2 cap, as used in ReEDS, is transferred manually into a CO2 price to simulate a CO2 emission restricted scenario in Memphis. For better representation, the Memphis model can be further expanded to allow imposing a CO2 cap. Similarly, as the benchmarking results of ReEDS with Memphis show, the representations of peaking technologies in ReEDS can also be improved so that the investment decision of peaking technologies can be more accurately computed.

Last, the analytical model can be further expanded to incorporate a large penetration of solar energy, or more features of a power system. The application of the analytical model in combination with computer based models could be of significant value in interpreting the behaviors of power systems.

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APPENDIX

Technology costs used in ReEDS Feb 2010 version for 2006 for this thesis									
2004 US dollars		**Capital**	**Fixed O&M**	**Variable O&M**	**Heat rate**	**Emission rate**	**Fuel price (EPPA)**	**Total variable costs**
Technology		US$/kW	US$/kW-year	$/MWh	(Mbtu/MWh)	tons/mmBTU	$/Mbtu	$/MWh
Coal	coal old scrubbed	1204	23.4	3.8	10.0	0.100	2.07	24.5
	coal old unscrubbed	1000	27.2	4.5	10.0	0.100		25.2
	coal IGCC	3908	27.2	5.7	9.0	0.100		24.4
	coal IGCC CCS	6140	38.9	9.3	11.8	0.100		33.7
Gas	Gas-CT	605	4.6	26.2	9.4	0.053	5.38	76.6
	o-g-s	395	25.3	3.6	9.3	0.053		53.4
	Gas-CC	1153	5.5	3.2	6.0	0.053		35.7
	Gas-CC-CCS	3420	16.1	8.8	9.1	0.053		57.6
Nuclear	nuclear	5624	111.6	0.0	9.7		0.54	5.2
Wind	onshore	1860	52.6	0.0				
	shallow offshore	3111	87.7	0.0				
Solar	CSP	4608	43.9	0.0				
	PV	4322	32.5	0.0				
Biopower		3737	83.3	13.2	14.50			
Geothermal		1	0.0	27.2	0.00			
Hydro		1320	12.7	3.2	6.00			