The Rockwool Foundation
CEBR

The Cost of Producing Electricity in Denmark

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Copenhagen 2014

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Published by

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ISBN 978-87-996384-1-3

November 2014

Foreword

The dynamics of the costs of generating electricity play a key role in the sustainability of Denmark's progress towards minimizing the use of fossil fuels in its power system. The cost of generating electricity as well as the costs of maintaining a secure and reliable supply of electricity are important consideration for designing policies aimed at minimizing greenhouse gas emissions. When introducing "green" technologies into a power system for generating electricity (wind turbines, for example), the costs of generating electricity, for a variety of reasons, may increase too drastically. Increasing costs could potentially reduce the standard of living of Danish consumers and deteriorate the global competitiveness of Danish industry through increasing producer and consumer prices. Importantly, prices might change to such an extent that the political support for further progress towards a fossil independent society vanishes. In other words, there are important trade-offs between progress towards a fossil fuel independent society and the increase in the production cost of electricity.

The evolution of Denmark's power system to relying less on electricity generated from fossil fuels raises a number of important questions: How does the relatively quick introduction of non-conventional generating technology (wind turbines) into a national power system affect the costs of generating electricity? There could be large effects on generating costs if (1) the new technology generates electricity at a higher cost compared to the existing technologies in the power system; (2) existing technologies cannot be phased out at a similar pace as the new technologies are being phased in, leading to over-capacity in the power system; and (3), the requirements of the existing power system to meet certain types of electricity demand could change. These are important issues that need to be considered when countries choose to introduce new generating technologies electricity into their power system. Leading examples include increasingly relying on renewable sources of electricity like wind or the substitution between conventional fuel sources like natural gas instead of coal.

The main objective of this project is to study the costs of generating electricity in the Danish power system. Specifically, we calculate and then compare the costs of generating electricity across different types of electricity generating technologies. The study provides an opportunity to measure the trade-offs involved with introducing new technologies into a power system.

The results of the study are reported in a series of two papers: The present study paper as well as in Levitt and Sørensen (2014). The purpose of the present paper is to present the results for the overall production costs of generating electricity in Denmark. This paper includes a summary of the main results of the study which is targeted for readers that may not have time for more intensive reading, e.g., policy makers. The paper also included detailed description of the Danish power system with main focus on thermal electricity generation technologies and developments in global fuel costs and carbon prices as well as a detailed analysis of aggregate costs of electricity generation in Denmark. Finally, the methodology we use to compute levelised costs are also documented in chapter 3. The twin study paper Levitt and Sørensen (2014) present the detailed calculations involved with computing the levelised costs of generating electricity for nine different thermal and non-thermal generating technologies. These detailed results are used as input in the analysis of aggregate costs of electricity production in Denmark presented in the present paper.

The project was carried out by researchers affiliated with the Centre for Economic and Business Research (CEBR) at Copenhagen Business School. The study group consists of Lecturer Clinton J. Levitt, Tasmanian School of Business and Economics at the University of Tasmania and Professor Anders Sørensen, Copenhagen Business School. We are grateful for the financial support from the Rockwool Foundation.

A special thank goes to the reference group of the project consisting of Professor Torben M. Andersen (chairman), Department of Economics, University of Aarhus, retired Executive Vice President Palle Geleff, Energy E2, and Associate Professor Emeritus Jørgen Birk Mortensen, University of Copenhagen. The reference group tirelessly gave comments and asked questions. We would also like to thank Mathias Tolstrup Wester and Casper Winther Jørgensen for efficient research assistance. The contents of this work are the sole responsibility of the authors and do not necessarily represent the views of The Rockwool Foundation. The authors have no conflict of interest in this work.

Clinton J. Levitt and Anders Sørensen, Copenhagen, November 2014

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Chapter 1

Summary of the Cost of Producing Electricity in Denmark

1.1 Introduction

What is the consequence on the costs of generating electricity when a new technology is introduced into a country's power system? There could be large consequences for aggregate production costs if (i) the new technology is producing at a higher cost compared to the existing technologies in the power system; (ii) existing technologies cannot be phased-out at a similar pace as the new technology is phased in, leading to over-capacity in the power system; and (iii), the requirements of the existing power system to meet certain types of electricity demand change. These are all important questions to address when countries decide to move towards new technologies for generating electricity. Leading examples include introducing renewable energy sources like wind or the substitution of conventional energy sources like natural gas instead of coal.

The main objective of this book is to study the costs of generating electricity in the Danish power system. Specifically, calculating and then comparing the costs of generating electricity across different types of generation technologies provides an opportunity to measure the trade-offs involved when new technologies are introduced into a power system.

By investigating the case of Denmark, this study provides important insights on the costs of overall electricity generation. Specifically, the actual average unit costs are estimated for the full generating capacity of the Danish power system. Denmark is a particularly interesting case to study because it is a world leader in terms of wind power penetration rates. In 2012, the wind power penetration rate in electricity consumption was equal to 30 percent, whereas it was equal to 34 percent for production, see International Energy Agency (2013). For comparisons, other regions are dwarfed by the Danish rates: The corresponding values were six percent for Europe, 3.5 percent for the US, two percent for China, and 2.5 percent for the world. The countries that are closest to Denmark in terms of wind power penetration rates are Portugal with 20 percent and Spain with 18 percent. Important lessons can be learned about the consequences of rapidly phasing-in a large amount of wind power on the electricity generating system. Studying wind power in Denmark is also interesting because wind penetration rates increased over a short period of time. In 1985, the share of wind power's generating capacity was essentially equal to zero. By 2012, the penetration rate of wind power in electricity consumption had increased to 30 percent.

The results on the costs of generating electricity obtained in this study are also of policy interest because the dynamics of the costs of generating electricity is an important determinant of the sustainability of Denmark's progress towards substituting away from electricity generated from fossil fuels. It is clear that the production cost of electricity must be an important consideration for policies designed to minimize greenhouse gas emissions–particularly policies involving subsidies. For example, if using renewable generation technologies increases the production cost of electricity too drastically, then the support for such investment may erode because the standard of living of Danish consumers as well as the global competitiveness of Danish firms could deteriorate through increasing producer and consumer prices. Importantly, energy prices might change to such an extent that the political support for further progress towards a fossil fuel independent society vanishes. In other words, there are important trade-off between progress towards a fossil fuel independent society and the increase in the production cost of electricity.

The purpose of the present chapter is to present a summary devoted to describing the main findings of the study presented in the present study paper and in Levitt and Sørensen (2014). This chapter is written with the purpose to present the main results in such a manner that the study can be well understood without reading the other chapters of the book. Of course, having said that, we hope that this chapter inspires readers to continue reading. Power system economics and the economics of energy in general, is an important part of a country's macro-economy as well as the economy of individual households. It is without question that issues concerning energy and the environment, and power systems specifically, compose a large part of public debate and policy discussions at various levels of national governments as well as international institutions. The outcomes of the various policy debates concerning energy affects everyone: It pays to be informed.

Our study of the costs of electricity generation in Denmark can be viewed as an important document for understanding the nature of costs of the electricity generation sector in its power system. Indeed, our analysis of the various costs of generating electricity has produced a number of interesting findings. However, determining the cost of generating electricity in Denmark involved many computations involving thousands of generating units. The good news is that the chapters in this book detail the many calculations as well as the assumptions involved with computing the costs of generating electricity. In addition, Levitt and Sørensen (2014) is technical companion document which details the many calculations for specific types of generating units. Analysis of the results of the many calculations are also included in the various chapters of the present paper as well as in Levitt and Sørensen (2014). These are important because knowledge of the details of the calculations, and the accompanying assumptions, are important for interpreting the reported results.

1.2 Electricity and the Environment

Generating electricity has historically been based on burning fossil fuels, coal, and to a lesser extent natural gas, a process that has resulted in the release of harmful emissions into the atmosphere. Perhaps the most significant and certainly the most discussed emission is carbon dioxide, CO_2, which is a greenhouse gas. The vast majority of scientific evidence indicates that global CO_2 emissions are having a warming effect on the climate.[1] Given the concern with the potential effects of global warming, there is general (political) agreement that there is a need for policy intervention to reduce these emissions.

The European Union has been at the forefront of policy initiatives designed to mitigate climate change and have adopted a number of energy and climate policy objectives for member states. These objectives include concrete targets for reductions in greenhouse gas emissions, substituting to renewable energy sources and improving overall energy efficiency. The corner stone of the EU's effort to reduce emissions of greenhouse gases is the European Union Emissions Trading System (EU ETS) which limits the overall emissions from high-

[1]For the most recent work on climate change see Intergovernmental Panel on Climate Change (2014).

emitting industries including electricity generation through a cap-and-trade system.[2] Electricity producers in Denmark are part of the EU ETS. Moreover, Danish domestic energy policy has actually set more demanding requirements than those established in international agreements. Specifically, Denmark has an objective of having an electricity sector that is fully based on renewable energy by 2035 (see Produktivitetskommissionen (2014), p. 66).

Comprehensive investments in renewable energy supply have taken place in the Danish power system directed at reducing the amount of greenhouse gases emitted into the atmosphere from generating electricity. These investment in renewable energy have been partly driven through active government policy. The two main policy instruments that have been used are CO_2-permits (EU ETS) and subsidies to the production of electricity using renewable sources of energy. Subsidies to electricity generated from a renewable energy source have been motivated historically by the conclusion that electricity generated from renewable sources is more costly relative to non-renewable generation (thermal generation, for example) which typically burn fossil fuels; a process which emits greenhouse gases into the atmosphere.

The main objective of this book is to study the costs of generating electricity in the Danish power system. Specifically, calculating and then comparing the costs of generating electricity across different types of generation technologies provides an opportunity to measure the trade-offs involved when new technologies are introduced into a power system. Such an analysis can only be performed if one is willing to make assumptions upon which the analysis is based. Throughout the analysis, we strive to make clear the assumptions behind the many computations involved in our analysis. In the next section, we motivate the analysis in more detail; we then describe the methods used in our analysis; and, finally, we give an overview of the results.

1.3 Moving Towards a Power System Based on Renewable Energy

Electricity generation is characterized by having large economies of scale. Because a significant portion of the costs of generating electricity are of the fixed variety, we break the costs of generating electricity down into two broad categories: fixed costs, which do not vary with the amount of electricity generated, and variable costs, which do vary with the amount of electricity generated. Importantly, fixed costs must be paid regardless of the amount of electricity that is generated. It is the existence of these large fixed costs that give rise to economies of scale: The greater is the amount of electricity generated by a unit, the lower are the average costs of generating electricity from that unit. The economies of scale nature of electricity generation - and therefore the estimation of capital costs - is important for this study. Therefore, we start by illustrating economies of scale using a simple example. The main source of fixed costs for a generation unit are the capital costs.[3]

A stylized example of a generator with economies of scale is illustrated in figure 1.1. In the figure, the average cost of a generating unit equals AC_0 (measured in kr per MWh) when the amount of electricity generated equals Q_0 (measured in MWh), whereas the generation unit has a lower average cost, AC_1, when the amount of electricity generated equals Q_1. The interpretation of falling per-unit costs is that when generation rates are high, more of the fixed costs can be distributed across the units of electricity produced thereby reducing average costs.

Economies of scale can affect investment decisions. For example, when choosing between different technologies for a new generation unit, that have different cost profiles, private investors will generally invest in

[2] A cap-and-trade system means that the overall volume of greenhouse gases that can be emitted each year is subject to a cap. The cap is enforced by requiring plants that emit greenhouse gases own emission allowances. Emission allowances are the currency of the EU ETS. Each allowance gives the holder the right to emit one tonne of CO_2. Emissions allowances can only be used once. Power stations receive or buy emissions allowances which they trade.

[3] For an interesting study of the economies of scale in electricity generation see Christensen and Greene (1976).

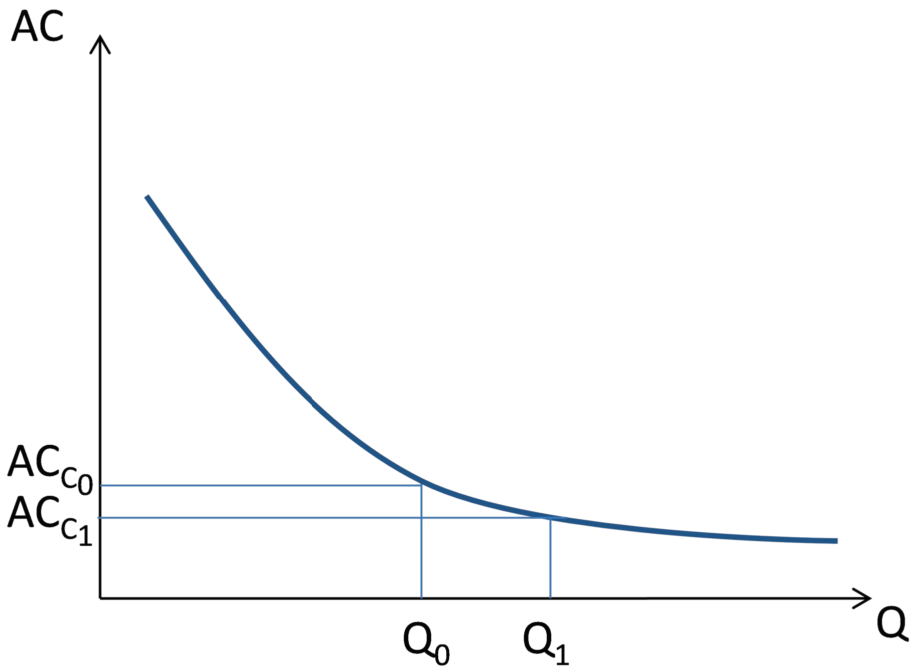


Figure 1.1: Economies of Scale and Average Costs

the less costly alternative (all else equal). We will illustrate this example in figure 1.2 where two alternative technologies are compared each having a different cost structure. One can think of these as being a conventional generation technology (a large coal-fired plant, for example) and a technology based on a renewable resource (a wind turbine, for example). In the figure, the wind turbine has relatively high fixed costs and relatively low variable costs, whereas the coal-fired generator has relatively low fixed costs but relatively high variable costs. The two technologies have a maximum capacity at Q_0.

It is clear that the conventional technology has lower average costs. Even though the wind turbine has relatively low variable costs, the technology cannot produce at an output level that makes private investments in the technology more attractive relative to the alternative. To create private incentives for investments in the technology, the government can introduce subsidies - covering part of the fixed costs and/or part of variable costs. If the government subsidizes wind energy by $AC_w - AC_c$ per unit produced, then this creates the private incentive to invest in the renewable energy. This is to a high extent the energy policy that is followed by the Danish government. Of course, the real world is not as simple as illustrated above. However, the illustration serve as a good description of the principles of electricity generation even though the real world is more complex.[4]

1.4 Overview: Motivation, Conclusions and Limitations

In sections 1.2 and 1.3 we discussed how government policy in Denmark supports investments in wind power thereby motivating a substitution away from electricity generated from conventional fuels to electricity generated from renewable sources. This policy raises an important question: What are the effects of this policy on the costs of generating electricity? We investigate this question by studying two important considerations:

[4]An important caveat: An active policy supporting investments in renewable energy may imply that the technology becomes a profitable investment in time without subsidies from a private perspective. This will be the case if "learning effects" are important in the sense that fixed capital costs fall or capacity increases over time. It is sometimes argued that onshore wind power has matured so much that it is competitive compared to more conventional technologies and that subsidies can be abolished.

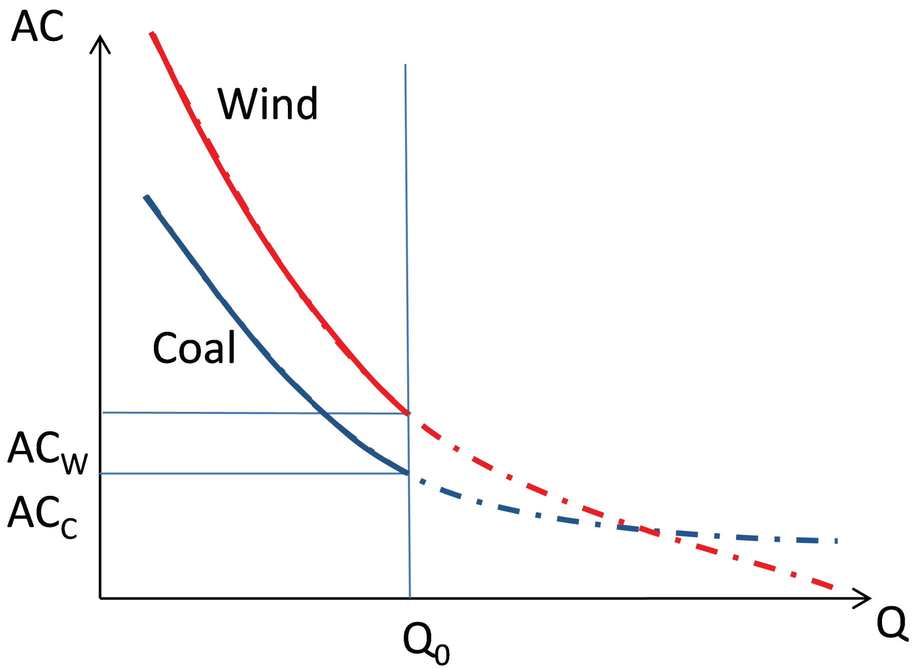


Figure 1.2: Investment

- The motivation for subsidizing investments in onshore and offshore wind power is to reduce CO_2 emissions by relying less on thermal generation. However, it is important to think about the consequences of changing the generation profiles for existing conventional generators. If new capacity results in the crowding-out of existing generation this may well result in low capacity factors for conventional generators, implying that the average costs of these generators will increase. This could result in greater overall average costs. The capacity factor refers to the ratio of actual output over a period of time to its (potential) output if it was possible for it to operate at full installed capacity.
- The electricity generated in Denmark cannot be stored.[5] Generation from an intermittent source like wind must have backup capacity to maintain a secure and reliable supply. Backup generators are likely to be small-scale generators and not large coal-fired central plants that serve base-load demand.[6] Backup generators can typically be started in a relatively short period of time and are typically more costly to operate than base-load generators. In this respect, it is important to know the production costs for the backup electricity capacity.

Motivated by these considerations, we study the following issues between 1998-2011:

- How has the overall production costs of electricity developed during this period of intensive increases in wind power penetration rates? A related issue is over-capacity in the power system. Over-capacity is a concern because it can potentially lead to inefficient generation levels for thermal technologies.
- During the analysis we search for indicators of the underlying changes in production costs. For example, we look for trends related to falling capacity factors. Low capacity factors lead to high average costs for single generators. In addition, we study the changes in the loads of different thermal technologies. We do this to identify changes that might have occurred across different types of generators each having

[5] Of course, given that Denmark trades electricity with Norway and Sweden, there is a degree to which electricity can be stored via hydro. However, even when we consider international trade, back-up capacity is still necessary.

[6] An alternative source for backup capacity is imports of electricity.

different capabilities: short ramp-up times or low minimum operating levels compared to generators with slow ramp-up times and high minimum operating levels.

- A counterfactual analysis is carried out to investigate what the production cost would have been under the thought experiment that no wind power capacity had been introduced into the Danish power system. Specifically, we investigate what the production cost would have been had electricity been generated using only existing thermal capacity.

Before presenting the conclusions, we present an important comment on the counterfactual analysis. This counterfactual analysis is related to studying consequences of over-capacity in the power system. An important requirement for this analysis is that the realized levels of electricity generated by wind power could have alternatively been produced using the existing capacity of thermal technologies. Our calculations suggest that the capacity of existing thermal technologies is of such a magnitude that this requirement is fulfilled during the period 1998-2011. Moreover, an important observation for electricity generation using thermal generators supports this assessment. For two years - 2003 and 2006 - thermal electricity generation spiked, which was caused by negative supply shocks in Norway and Sweden. This prompted thermal generators to increase production. For these two years, electricity generated from thermal technologies was of a magnitude equal to the aggregate electricity generated in an average year. This observation indicates that aggregate electricity generation alternatively could have been produced using only existing thermal capacity instead of relying on both thermal and wind power generation.

The main conclusions related to the average unit production costs that we establish are:

- The overall production cost of electricity has a positive trend over the 14 year period from 1998 to 2011. This trend is to a large extent due to increasing fuel prices which are determined in global commodity markets. Overall, average capital costs did not exhibit a positive trend. This is the case even though the Danish generation capacity increased by 20 percent, while total electricity generation did not show much of a trend.
- The results indicate that average capital costs have not increased as the substitution between generating technologies has kept average capital costs essentially unchanged. Specifically, we find that the capital costs of wind turbines declined and became relatively low in later years of the period under investigation. Hence, substitution into wind power did not increase average capital costs. To a large extent, substitution took place between thermal technologies and wind power, but there was also substitution within the group of thermal technologies. In conclusion, extensive introduction of electricity generation from renewable resources, i.e., wind power, has not increased the average capital costs during the period 1998-2011.
- Even though increasing wind power penetration rates did not increased the average cost of generating electricity, the average costs of generating could have been lower. This result is established using a counterfactual analysis where all electricity generation was assumed to be generated by existing thermal capacity. The average unit costs of production could have been 13 percent lower on average if wind power had not been phased into the power system. It is higher capacity factors and thereby lower capital costs that generate lower unit production costs in the counterfactual case.

Moreover, the technology specific results that we establish are:

- Unit production costs have increased for a large part of thermal generation technologies primarily due to increases in fuel prices.
- Capital costs have not increased for those technologies with the highest generating shares of electricity.
- The share of electricity generated by wind turbines increased over the period: Shares increased from 7

percent in 1998 to 28 percent in 2011. The share of costs have, however, only increased from around 8 percent to 18 percent during the same period, indicating that wind power are relatively inexpensive technologies.

- For some technologies, average capital costs increased. This was the case for a number of thermal technologies that had low and decreasing production shares. These technologies accounted for 9.4 percent of total deliveries in 2011 compared to 23.1 percent in 1998. Even though the share of deliveries dropped dramatically, the cost share of overall average production costs for these technologies only dropped from around one third in 1998 to 23 percent in 2011. This implies that electricity generated using these technologies was relatively expensive.
- Thermal technologies with long and costly startup times - often serving base-load demand - have a decreasing share of electricity deliveries; falling from three quarters in 1998 to about one half in 2011. The share of costs have, however, only dropped from around three quarters to 60 percent during the same period, suggesting that these are relatively expensive technologies.
- Thermal technologies with short startup time - often serving peak-load demand/backup supply - have an unchanged/slightly increasing share of electricity deliveries; around one fifth in 2011. The share of costs have been relatively stable and around one fifth during the period under investigation.

Finally, it should be stressed that there are important limitations to the analysis that readers should keep in mind. The most important ones are:

- We calculate the direct costs of generating electricity. That is, we compute capital costs, operation and maintenance costs, fuel costs, etc. We do not measure the costs of externalities. For example, we do not include the social costs of emitting carbon dioxide, CO_2, into the atmosphere. This is an important limitation since this cost is the main reason for being concerned about emissions and is the main impetus for policies designed to limit these emissions. Still, an analysis of the costs bringing wind power into a power system is important because it informs the design policies aimed at reducing emissions.
- The analysis presented in this book is a cost analysis. We do not evaluate economic and environmental policies that influence the Danish power system. In other words, we take economic and environmental policies as given and do not, for example, analyse how policies have influenced decisions to invest in or scrap generators belonging to certain technologies.
- We do not analyse the market price of electricity. An analysis of the market price of electricity would be interesting. For example, we find that the phasing-in of wind power generated over-capacity in the Danish power system. This result leads to the important question of how over-capacity influences the supply decisions of electricity producers. Answering this and related questions is beyond the scope of this book.
- In the analysis we do not have access to actual investment data. Instead, we rely on information contained in technology manuals which report standard figures for different types of generation technologies. This data is used to deduce the investments costs of generators. In addition, we apply estimates for maintenance costs from technology manuals. A limitation of this data source is that we do not have access to data on re-investments for existing generators. We have tried hard to find information on re-investments - for example - from annual reports of the largest Danish energy companies, however, we were not able to find any usable data.
- In principle, cost measures should be adjusted for co-products as well as by-products from electricity generation. We are able to carry out such adjustments for heat production by combined heat and power plants. In addition to this, we also wanted to adjust production costs for by-products of electricity generation that have value. Such by-products include (1) fly ash, which is sold to the concrete industry,

(2) lime and gypsum (and TASP) which is then sold, and (3) ammonia. Unfortunately, it was impossible to obtain data on the revenues from the sale of these by-products. A data source that potentially could include this data is Supply-and-Use tables maintained by Statistics Denmark, however, it turned out that the needed information was not included. The consequence is that we slightly over-state production costs for some thermal technologies. The omission of this information only lead to minor bias in the cost estimates.

- All costs refer to pure technological costs, i.e., costs without plant or fuel specific taxes and production subsidies. This is because the main interest is the pure technological production costs of electricity.

In the remainder of this chapter we describe the methodology and review our main results in more detail.

1.5 Methods

The core calculations involve computing the levelised costs of generation (LCG) as well as levelised costs of electricity (LCE). LCG is defined as the annual costs of capital, fuel, operations and maintenance, and emission costs divided by the production of electricity of a technology.[7] The result is a cost in Kroner per megawatt hour (or gigawatt hour). In addition, we calculate a measure of system-wide costs and make adjustments for the international trade in electricity.

1.5.1 Levelised Cost of Generation

The average cost of generating electricity depends on the mix of generators each having different production characteristics. Broadly, Denmark uses a number of different technologies to produce electricity including combined-heat-and-power (CHP) generators as well as offshore and onshore wind turbines. In addition, thermal generators in the Danish power system use a number of different fuels.

We calculate the production costs for each type of generator. In order to compare the costs of generating electrcity between different types of generators we calculated a commonly used index of long-run costs known as the levelised cost of generation (LCE). The levelised cost of generation is a summary measure of the average cost of generating electricity per kilowatt-hour expressed in today's money.

Finally, we take into account that costs associated with generating heat must not be included in the costs of generating electricity. CHP generation is the cornerstone of the Danish power system. Therefore, a study of the costs of generating electricity in a power system consisting of a large number of CHP plants must recognize the benefits of CHP generation: Potentially wasted heat is transformed into usable heat substantially increasing efficiency rates.

For this study, the levelised cost is calculated at the generator level for more than 1,000 thermal generation units and around 7,000 wind turbines. Levelised cost is the appropriate summary measure because it allows for a direct comparison between generating technologies. For example, if we only calculate costs per year (and not per output) then a standard coal fired plant will have annual costs far exceeding an onshore windmill. In this case one cannot compare the costs of producing electricity because the productivity of the technology is not considered. However, if costs are calculated per unit of output then we can directly compare how much it costs to produce one unit of output across a divers set of technologies.

[7]Specifically, yearly cost for capital is determined as the amortization of the investment cost over the (expected) lifetime of the generator. This means that the investment costs are divided into equal amounts for the expected lifetime such that the net present value of the amortized value equals the investment costs.

1.5.2 Levelised Cost of Electricity

Once we have the levelised costs for each generator we constructed an aggregate measure of generation costs by weighting the levelised cost of each generator according to its production shares. We refer to this measure as "levelised costs of electricity".

1.5.3 Net Generation Costs

To obtain gross generation and supply costs, we adjusted the levelised costs of electricity for two additional factors. First, we compute a measure of system-wide costs. Second, we adjusted generation costs for the production costs of net-exports, i.e., for exports and imports of electricity, to reach at a cost measure related to the Danish consumption of electricity.

An additional feature of electricity generation that adds to the costs of supplying electricity in the Danish system is the cost of ancillary services. Ancillary services consist of different types of reserve capacities that can be called to ensure that the Danish power system is in balance. Changes in consumption and/or disturbances in supply can destabilize the power grid (deviations in grid frequency). Typically, the Transmission Systems Operator (TSO) buys reserve capacity to ensure reliability. In Denmark, *Energinet.dk* buys ancillary service to ensure reliability in the grid.

Reserve capacity is required by a power system even if only coal or gas powered plants are used. However, the amount of reserve capacity also depends on the wind power penetration rate in any period. In general, the larger is the wind penetration rate the more reserve capacity that is required to maintain a stable system. The implication is that the more wind power that is part of the grid the more reserve capacity that must be procured. Of course, this is an additional cost of increasingly relying on wind power to generate electricity.

One way to think about reserve capacity is that there are two types of broadly defined costs associated with ensuring reliability on the grid: (1) the cost of reserve capacity even if it is not used to generate electricity; and (2) the cost of generating electricity from the reserve capacity. Capacity can either be offered by generators already running (but not at full capacity) or from generators requiring a black start.[8] In the calculation of the LCG we try to identify generators serving base-load and those generators serving peak-load to get at the cost differences. Since this was difficult to do in practice, we used an alternative grouping of generators: Those with slow startup time and those with fast startup time.

System-wide costs are important when considering alternative energy sources that are variable like wind. Therefore, we include an analysis of system-wide costs in the calculations of unit costs of electricity generation. However, first we calculate LCG and LCE to maintain the focus on generation costs without including system-wide costs. This provides the costs of producing electricity that are largely independent of the regulatory structure.

Finally, we also adjust the total costs of generation related to the net-exports of electricity and divide it by aggregate electricity generation. The purpose is to construct a measure of the unit production costs of generating electricity for Danish electricity consumption. It must be stressed, however, that this measure is based on a number of restrictive assumptions. First, the assumption that electricity prices equal average costs of production is required to insure that revenues from exports and imports reflect costs. Second, we must assume that electricity is a homogenous product. Moreover, we are aware that the measure involves mis-measurement because the corrected cost measure should in principle be divided by the volume of electricity consumption and not electricity production. However, we do not have a measure of the volume of electricity consumption.

[8] A black start is the process of restoring a power station to operation without relying on the external electric power transmission network.

1.6 Applied approach to LCG

Before presenting the results of the study in more detail, we first explain how our approach deviates from the standard approach of calculating levelised costs of generating electricity. The differences turn out to be very important for understanding our results. The purpose of using the standard approach of calculating the LCG is to provide information for investment decisions in new vintages of generation resources. This implies that the measure is forward looking and can be interpreted as the potential levelised cost of generating electricity of new investments. The standard LCG is based on unrealised costs and output of different production technologies.

The approach used in this project for calculating LCG differs from the standard LCG in the following ways:

- The LCG electricity computed in this study is a measure of realized levelised costs and should not be interpreted as a potential measure. The important distinction is that the LCG we calculate is based on realized costs and output to the greatest extent possible. This difference turns out to be important. In particular, the difference between actual production of electricity versus projected levels results in significant differences between the actual LCG electricity and the forward LCG.
- The LCG we compute is based on the existing stock of production capital – not on new generation resources only. Specifically, we calculate the production costs of all existing generators in the Danish power system. By computing the LCG for all generating resources we can calculate an average cost of production for the whole electricity system.

Next, we discuss consequences of LCG and LCE of the two measures in greater detail.

1.6.1 The Standard Approach

As mentioned above, the LCG of new generation resources is the standard LCG measure. This measure is used to evaluate the costs of alternative investments in new generation resources and is an important input for policy making. The standard LCG basically provides a measure of the average costs of additional generation capacity (or replacement capacity). The measure is based on assuming that additional capacity will be used without affecting the use of existing capacity. In other words, the standard LCG measures the costs of additional units of capacity given that additional generation does not crowd out existing generation.

Moreover, since the standard LCG is forward-looking assumptions concerning capacity factors must be made, i.e., the ratio of actual output over a period of time to its (potential) output if it was possible for it to operate at full installed capacity. The assumption is that there is room for new generation capacity and that it can operate at a "normal" capacity factor. For coal - a conventional thermal production technology - production is assumed to take place for a capacity factor of 75-85 percent; for onshore wind the capacity factor is assumed to be around 34 percent, see U.S. Energy Information Administration (2014) and Danish Energy Agency (2014).

Consequently, the potential effects of new investments on the costs of generating electricity by existing generators are not included the calculations. The crowding-out of production by existing generators from new investments may result in higher average costs. This cost is not taken into account standard levelised costs of generation calculations.[9]

[9] It can be argued that the impact on existing production capacity can be disregarded when comparing costs of investing in two technologies, since it is the cost difference between the two technologies that matters. However, to get the full picture of increasing capacities, cost related to crowding out of existing production capacity should be taken into account, especially, in the Danish case where the wind power penetration rate has increased dramatically during the 14 years under investigation.

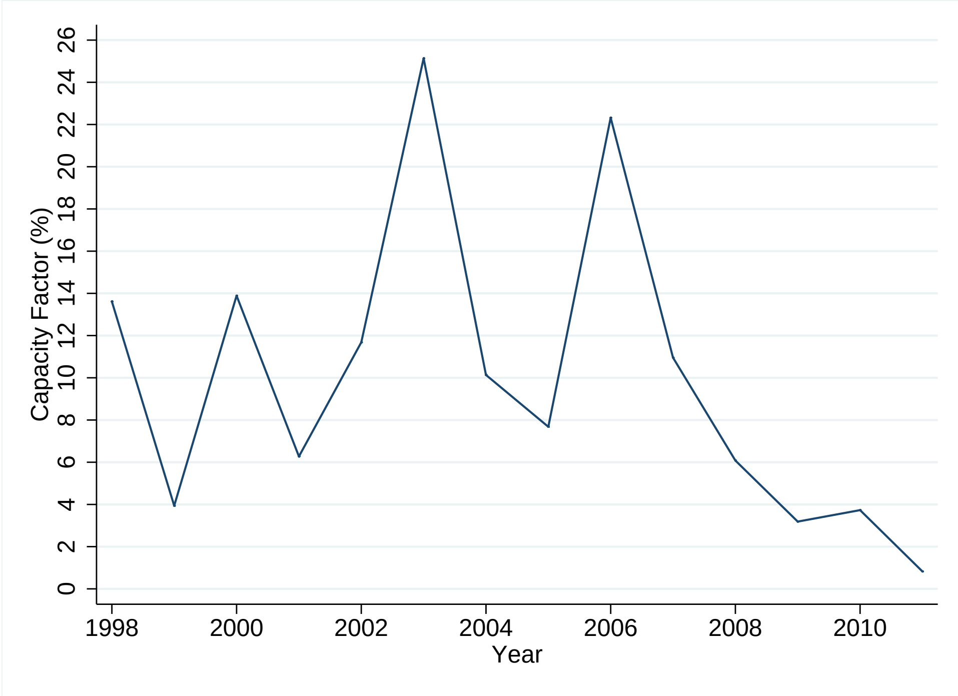


Figure 1.3: Capacity Factor for Steam Condensing Generators, 1998-2011

1.6.2 The Approach Used in this Study

Our approach to computing the LCG in this study is not based on the newest vintages of the technology only but covers the entire stock of generators in the Danish power system. The measure serves two purposes: First, the LCG is used to compare average costs of different existing generators; Second, the LCG is an important factor in determining the average production cost for the total generation capacity of Denmark. This measure is the levelised costs of electricity (LCE) and is calculated as a weighted average of the LCGs using production shares as weights.

To illustrate the consequence of using realized costs and production in the calculations of LCG we present the actual capacity factor of steam condensing generators for the period 1998 to 2011 in figure 1.3, keeping in mind that the standard LCG would use the potential capacity factor in the range of 75-85. Steam condensing generators experienced decreasing generation levels going from around 10 percent of total electricity production in 1998 to less than 1 percent in 2011. Consequently, capacity factors were very low. Between 2007-2011, the capacity factor is substantially lower than any potential factor. Low capacity factors lead to high LCG for these generators.

We also present the realized capacity factors for wind power. The current “normal” capacity factors are 34 percent for onshore wind turbines and in the range 46-48 percent for offshore wind power, see Danish Energy Agency (2014). Since wind power is still a technology that has not fully matured yet, we cannot expect that older vintages of wind turbines have the same capacity factor as current vintages. Therefore, an increasing trend in capacity factors should take place over time as new more efficient vintages are introduced and old vintages are taken out of production. In addition, scouting new locations for wind turbines play an important role in capacity utilization rates.

In figure 1.4 it is seen that the capacity factor for onshore wind turbines attains an average value around 20 percent from 1998 to 2011. Moreover, the variability of the capacity factor is increasing. Surprisingly, the capacity factor does not seem to increase over time. Moreover, the realized factor is well below the “normal”

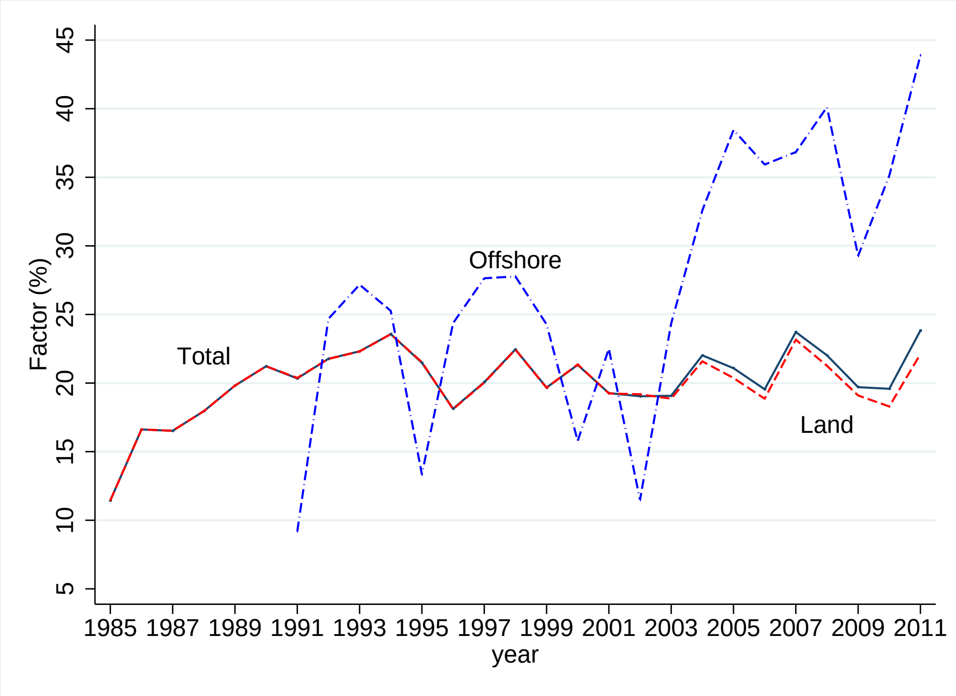


Figure 1.4: Capacity Factors, Wind Turbines, 1985-2011

rate of 34 percent. For offshore wind turbines the realized capacity factor has an increasing trend attaining a value close to 45 percent in 2011.

The two figures report actual capacity factors which were calculated from production data. One important observation is that the technology of conventional thermal electricity generators are largely matured and the capacity factor is low for steam condensing generator. This suggests to that conventional thermal electricity production to some degree operates at a relatively high average costs.

1.7 Results

In this section, we review the results established in this book in greater details than previously discussed in section 1.4. First, we present the mix of generation capacity and the development thereof during the years 1998 to 2011. Second, we present the results for electricity generation. Third, we present detailed descriptive statistics for different technologies. Fourth, we present the levelised costs of generation, LCG. Fifth, we present the levelised costs of electricity, LCE, with and without adjustments for system-wide costs and net-exports. Sixth and finally, we present result for the counterfactual case with no electricity generated by wind power.

1.7.1 Mix and Trends in Capacity

The aggregate electricity generation capacity of the Danish power system was approximately 13.3GW in 2011, increasing by 20 percent from the 1998 level of 11.1GW. In table 1.1, we report the capacities of thermal CHP units, wind turbines and conventional units (by conventional we mean generators that only produce electricity). Looking at the composition of the changes to the capacity levels produced interesting results. The contributions made by the different classes of generators (wind, CHP and conventional) have changed substantially over the years. The significant event that has spurred these changes was the substantial increase in investments directed at increasing the penetration rates of wind power. Indeed, the aggregate capacity of wind turbines almost

Table 1.1: Electricity Generating Capacities

	Capacity Levels (MW)				Capacity Share (%)		
Year	Electricity	CHP	Wind	Total	Electricity	CHP	Wind
1998	1030.70	8,586.40	1,438.44	11,055.54	9.32	77.67	13.01
1999	878.70	8,468.40	1,758.93	11,106.03	7.91	76.25	15.84
2000	875.70	8,500.40	2,397.67	11,773.77	7.44	72.20	20.36
2001	875.70	9,084.90	2,502.36	12,462.96	7.03	72.90	20.08
2002	614.00	9,138.30	3,001.04	12,753.34	4.81	71.65	23.53
2003	616.60	8,880.40	3,138.11	12,635.11	4.88	70.28	24.84
2004	616.60	8,919.10	3,131.16	12,666.86	4.87	70.41	24.72
2005	616.20	8,983.60	3,146.03	12,745.83	4.83	70.48	24.68
2006	617.50	9,009.60	3,139.52	12,766.62	4.84	70.57	24.59
2007	646.90	8,996.30	3,138.63	12,781.83	5.06	70.38	24.56
2008	662.60	8,954.90	3,201.90	12,819.40	5.17	69.85	24.98
2009	663.40	8,888.00	3,516.66	13,068.06	5.08	68.01	26.91
2010	664.10	8,885.20	3,846.37	13,395.67	4.96	66.33	28.71
2011	664.20	8,596.30	4,005.33	13,265.83	5.01	64.80	30.19

[a] Authors own calculations.

tripled between 1998 and 2011; wind turbine's share of capacity increased from around 13 percent in 1998 to 30 percent in 2011.

This dramatic increase has been at the expense of cogeneration capacity which has dropped from a contribution of 78 percent to 65 percent. The capacity measure in MW, however, stayed almost constant during the period. The share of thermal electricity capacity by conventional generation declined from about 9 percent in 1998 to 5 percent in 2011 corresponding to a drop of one third in capacity.

The evolution of wind capacity is illustrated in figure 1.5. The figure illustrates the development wind generation capacity: Capacity increased dramatically from a very low level in 1985 to around 1.5 GW in 1998 and further up to around 4.0 GW in 2011. The largest increase took place between 1995 and 2002 and was mainly driven by investments in onshore turbines. There was an important difference between the periods before and after 2002 since the increase in wind power generating capacity was driven by both new onshore and offshore wind turbines. In 2011, offshore turbines accounted for almost one quarter of total capacity of wind turbines.

With the large increase in electricity generating capacity from wind power in mind, we turn to realized electricity generation.

1.7.2 Mix and Trends in Electricity Production

The average amount of electricity produced over the 14 years was around 39 thousand GWh.[10] There is no significant trend in the amount of electricity produced over the 14 years. However, there is annual variation in generation. In 2006, over 43 thousand GWh of electricity was generated in Denmark, whereas in 2011, about 35 thousand GWh was generated.

Electricity production together with the development of generation capacity have important implications: The building up of over-capacity which will be reflected in the overall lower capacity factors. The overall capacity

[10] The production data for thermal generators used in this section are comprehensive data on thermal generators operating in Denmark provided by Danish Energy Agency. Aggregate production from this source deviates slightly from the Danish Energy Agency's Monthly Electricity Supply Report 2011 (see table 4.1. of chapter 4). The applied data set on thermal generators operating in Denmark cover 1998 to 2011. These data consists of 796 plants that operated between 1998 and 2011. Plants often operated more than one generator. The data contain information about the production and the technological attributes for 1145 unique generators.

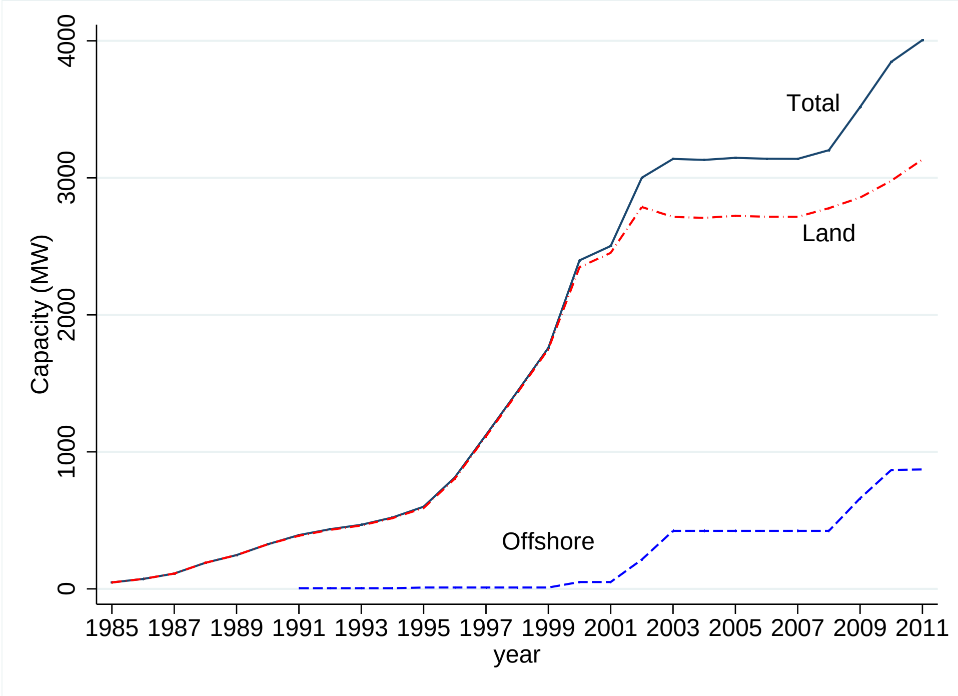


Figure 1.5: Capacity, Wind Turbines, 1985-2011

factor, the capacity factor for thermal technologies and the capacity factor for wind power are illustrated in figure 1.6. Capacity factors for thermal units had a negative trend and drops from 45 percent in 1998 to 28 percent in 2011. In contrast, the average capacity factor for wind turbines had been increasing since 1998. The result is that the average capacity factor across all generation units had been declining since at least 1998.

The mix of generators is presented in figure 1.7. The figure reinforces the significance of CHP in Denmark as well as the introduction of wind power and the phasing-out of conventional thermal electricity generation. In 2011, wind power generated 28 percent of aggregate electricity production. The vast majority of electricity produced by thermal generators has been by CHP-generators. A number of important trends are illustrated in the figure. First, with respect to wind power, production shares have increased from 7 percent in 1998, implying an increase of 21 percentage point over the 14 year period. In other words, the share of aggregate electricity production of wind power increased by 1.5 percentage points per year which resulted in the tripling of the amount of electricity generated by wind power. Production by thermal generators fell correspondingly by 1.5 percentage points a year.

Second, the bulk of electricity produced by thermal generators has been by CHP generators. Average annual electricity production by CHP generators was 31,910GWh. So, over the sample period, more than 97 percent of electricity produced by thermal generators was produced by CHP plants.

When examining the trends in thermal generation, the striking feature of the data is the rapid decline of conventional generation since at least 1998. In 1998, conventional thermal generators produced approximately 2,600 GWh of electricity, but by 2011, they were generating less than 100 GWh of electricity. Consequently, the share of electricity generated by conventional thermal generators has declined from about seven percent in 1998 to less than a quarter percent in 2011. Conventional thermal generation capacity has also decreased since 1998, but the trend has not been as severe as production.

Another important feature of the data presented in figure is the spikes in thermal electricity generation - i.e., conventional and CHP - observed in 2003 and 2006. These spikes were primarily caused by negative supply shocks in Norway and Sweden, which prompted these generators to use more of their capacity. In particular,

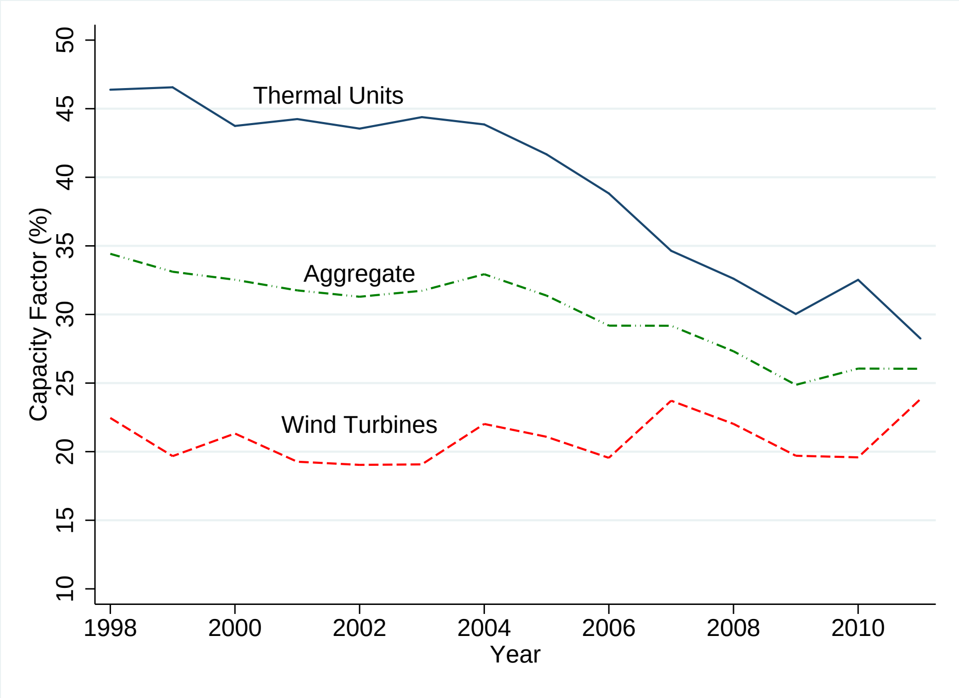


Figure 1.6: Mean Capacity Factors 1998-2011

low levels of hydro resources in Norway and Sweden prompted the increase in production. A very important implication of this observation, is that the capacity of thermal electricity generation is of such a magnitude that it - in principle - could produce the full average amount of electricity produced of around 39 thousand GWh.

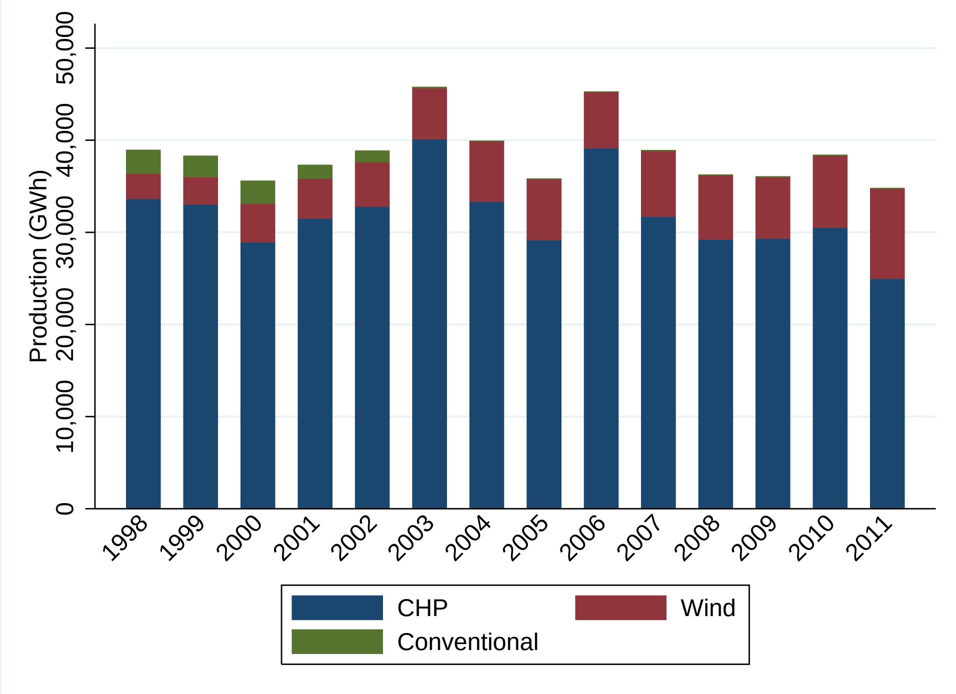


Figure 1.7: Generation, 1998-2011

Electricity generated by wind power is presented in the figure 1.8. The vast increase in electricity generated by wind power is evident from this figure: Production increased from virtually no production in 1985, to 2,800 GWh in 1998 and increased further to almost 10,000 GWh in 2011. Since 2002 the contribution from offshore wind power increased to around 3,400 GWh in 2011 constituting as much as 34 percent of production from wind power. This share is contrasted by the share in capacity, where offshore turbines account for a little less than on quarter of total capacity of wind turbines. The result speaks to the fact that the capacity factor of offshore wind turbines is higher than that of onshore wind turbines.

In Chapter 4 of the book, we show that the there was a decline in the mean production of both conventional thermal generators and CHPs and the decrease in conventional production was a consequence of phasing-out of that technology. Lower mean production of CHPs, however, cannot be explained by phasing-out of CHPs as a source of electricity production. This raises an important question concerning Danish generation. Why has the mean production declined for CHP plants and is this trend related to phasing-in of wind power? More precisely, could the change be a structural one: more usage of backup production after all CHPs can deliver electricity quite quickly if they are already generating heat? Intermittency and the non-dispatchable nature of wind energy production have system-wide implications: In order to maintain a secure supply of electricity reliable backup generation must be made available.

Before turning to the presentation of results for levelised costs of generations (LCG) and levelised costs of electricity (LCE), we present the share of production conditional on the type of generator. We study seven types of thermal generators and two types of wind turbines. Conventional thermal generators include steam turbines, CHP generators consist of steam turbines (back pressure and extraction) as well as combined-cycle gas turbines and CHP waste.

Generation shares are reported in table 1.2. Generation shares declined for most thermal technologies. This is the case for all steam turbines as well as gas turbines and gas engines. It is striking that condensing generators

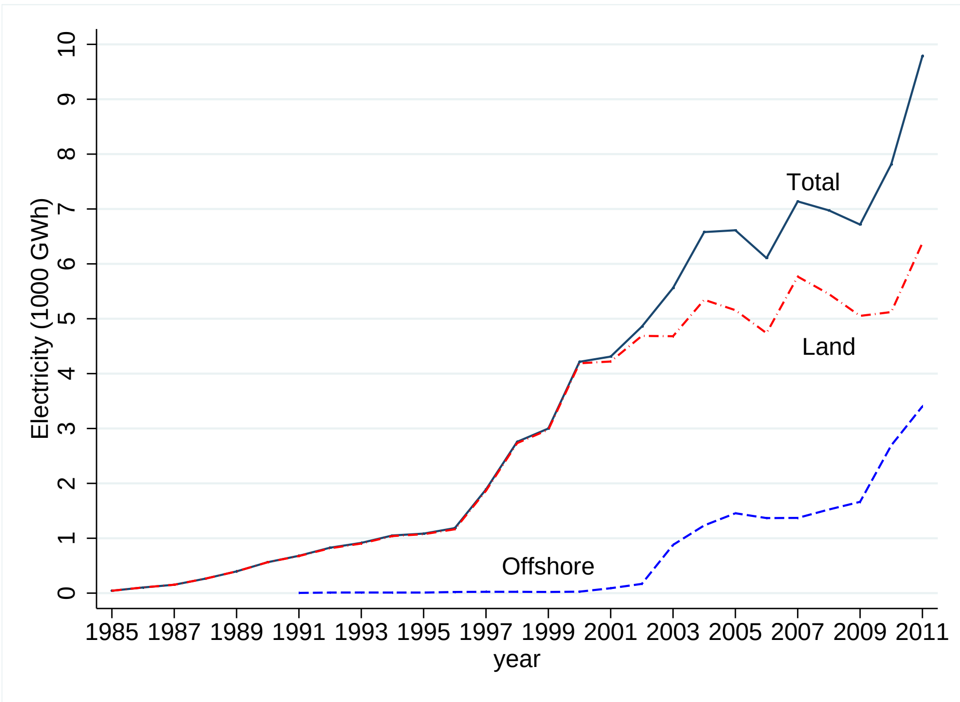


Figure 1.8: Electricity Delivered, Wind Turbines, 1985-2011

Table 1.2: Share of Electricity Generation, 1998-2011 (%)

Year	Steam Turbine: Condensing	Steam Turbine: Back Pressure	Steam Turbine: Extraction	CHP Waste	Combined Cycle	Gas Turbine	Gas Engine	Land Turbines	Offshore Turbines
1998	10.03	6.63	56.29	1.85	4.92	3.16	9.92	7.02	0.06
1999	6.81	6.89	56.51	2.28	5.57	3.84	10.14	7.77	0.06
2000	9.86	5.90	49.40	2.54	6.08	3.73	10.54	11.77	0.08
2001	5.79	5.45	53.38	2.57	6.77	3.62	10.75	11.31	0.24
2002	5.82	5.95	49.26	2.46	10.11	3.44	10.39	12.06	0.44
2003	5.02	6.11	52.78	2.30	9.72	3.10	8.77	10.22	1.92
2004	2.63	5.49	47.31	2.42	11.60	3.80	10.20	13.38	3.09
2005	2.10	5.49	44.52	3.63	11.58	3.69	10.50	14.39	4.06
2006	4.31	4.30	53.84	2.94	10.80	3.06	7.27	10.46	3.02
2007	2.82	4.47	51.46	3.33	9.89	2.78	6.90	14.82	3.52
2008	1.91	4.35	49.48	3.72	10.71	2.99	7.59	15.04	4.20
2009	0.79	4.40	53.40	3.60	9.82	2.56	6.80	14.01	4.61
2010	0.64	5.71	48.64	3.20	11.35	2.31	7.69	13.33	7.01
2011	0.21	5.41	42.65	3.77	10.49	2.25	6.97	18.33	9.78

[a] Authors own calculations.

were virtually phased out of electricity generation. Two thermal technologies increase their share of electricity production. These are CHP waste and combined cycle. Finally, the phasing-in of wind power is evident through increasing generation shares throughout the 14 year period.

The technologies can be grouped by startup times, which to some extend reflect whether they can serve base-load demand or peak-load demand/backup supply. The four former technologies - Steam Turbine (Condensing, Back Pressure, Extraction) and CHP waste - all have slow startup times, whereas the three latter technologies - Combined Cycle, Gas Turbine and Engine - have fast startup times. An interesting development is that the share of electricity production with slow startup time from thermal technologies has dropped from 75 percent to around half of the electricity production. This is in contrast to thermal technologies with fast startup that has increased slightly to around one fifth in 2011.

The change in shares of total electricity delivered may indeed have effects on capacity factors. This is especially true for technologies where the shares of total delivered decreases, and the decrease is not a result of decommissions. In table 1.3, we present the capacity factors for the different technologies. It is clear from the table that many of the thermal generation technologies that have falling shares of total delivered also experience falling capacity factors. Actually, the capacity factors fall for all thermal technologies except for back pressure.

1.7.3 Levelised Costs of Generation by Type of Generator

In this section, we present the levelised costs of generation (LCG). Detailed description of the many calculations and their interpretation are provided in the companion paper Levitt and Sørensen (2014). The costs for different types of generators are reported in table 1.4.

The LCGs vary extensively across technology types. The technology with the lowest cost was CHP waste with 312 kr/MWh in 2011, whereas the technology with the highest cost was condensing generators with a cost as high as 25,785 kr/MWh in 2011. It is also evident that LCGs of all thermal technologies except CHP waste increased during the 14 year period 1998-2011. In contrast, the LCG of wind power declined over the same period. The dramatic increase in the costs of condensing generators was due to the phasing-out of the technology resulting very low production levels and extremely low capacity factors. The most important thermal generators were extraction, combined cycle, and gas engines with average production shares of 43 percent, 10 percent and 7 percent, respectively, in 2011. The remaining production shares were 5 percent for back pressure generators, 0.2 percent for condensing, 2 percent for gas turbines, and 4 percent for CHP waste in 2011.

The LCGs for the most important thermal production technologies, extraction, combined cycle, and gas engines increased, as opposed to LCGs of wind power which decreased. In order to understand the increase in LCGs it is important to remember that the LCGs are composed of capital, fuel, operation and maintenance, and emission costs. It turns out that increasing fuel prices were important reasons for the increases the LCG for thermal technologies as well as rising capital costs (low capacity factors) for some generators. Therefore, we turn our attention towards capital costs and fuel costs.

In table 1.5, the part of LCGs that is constituted by capital costs is presented.[11] It is clear that capital costs increased for gas turbines, condensing turbines and gas engines. These three types of generators experienced large decreases in their capacity factors. In this sense, increasing capital costs should be expected. For the

[11] Once again, for a detailed description of how captial costs were calculated and sources of data see Levitt and Sørensen (2014).

Table 1.3: Capacity Factors, Generation Unit, 1998-2011 (%)

Year	Steam Turbine: Condensing	Steam Turbine: Back Pressure	Steam Turbine: Extraction	CHP Waste	Combined Cycle	Gas Turbine	Gas Engine	Land Wind Turbine	Offshore Wind Turbine
1998	9.82	35.42	49.47	62.98	38.58	54.30	46.26	22.44	27.77
1999	3.28	36.79	48.44	68.16	43.20	55.90	46.10	19.66	24.28
2000	9.26	34.59	39.24	70.04	43.58	51.96	43.30	21.36	15.79
2001	5.23	28.98	43.98	73.86	43.13	47.32	44.28	19.25	22.50
2002	11.68	29.94	41.59	71.37	45.19	48.81	43.09	19.18	11.49
2003	25.13	34.07	56.40	79.45	44.85	51.56	43.23	18.87	24.34
2004	10.14	32.15	44.49	67.23	46.24	52.73	43.65	21.59	32.59
2005	7.68	30.59	37.19	74.92	42.89	52.90	41.21	20.37	38.45
2006	22.32	29.98	55.41	77.33	41.43	47.59	37.87	18.86	35.93
2007	10.96	30.36	46.97	76.11	38.73	39.71	33.81	23.16	36.84
2008	6.08	30.42	40.74	76.66	36.61	41.72	31.58	21.26	40.11
2009	2.55	29.65	44.62	73.29	35.49	35.66	28.93	19.10	29.28
2010	2.99	40.22	47.24	69.31	41.82	34.77	31.56	18.30	35.11
2011	0.66	37.07	37.07	76.03	33.50	30.74	27.43	22.11	43.90

[a] Authors own calculations.

Table 1.4: Generator Levelised Costs, 1998-2011 (kr/MWh)[a]

Year	Steam Turbine: Condensing	Steam Turbine: Back Pressure	Steam Turbine: Extraction	CHP Waste	Combined Cycle	Gas Turbine	Gas Engine	Land Wind Turbine	Offshore Wind Turbine
1998	1000.07	1462.93	278.75	494.13	318.89	858.32	407.76	556.70	896.30
1999	1280.61	1356.73	288.87	412.78	286.28	716.41	395.11	578.16	1003.76
2000	1004.54	1645.71	347.04	403.78	372.39	906.89	476.86	527.88	2407.44
2001	1548.61	1694.23	309.81	379.07	434.18	884.46	457.54	543.63	813.66
2002	1455.12	1602.65	306.11	391.14	317.58	802.03	422.71	543.09	1219.90
2003	1110.56	1284.14	246.14	349.47	326.57	792.09	437.85	524.73	569.79
2004	2178.31	1579.03	361.52	425.89	301.96	805.03	437.89	467.38	441.85
2005	3016.26	1622.45	425.39	310.10	354.65	926.51	483.02	473.24	393.40
2006	1349.31	1596.19	243.03	313.68	371.21	957.50	567.70	501.60	410.69
2007	2155.21	1511.79	339.55	339.54	461.10	1128.14	661.80	424.42	410.23
2008	3352.58	1899.98	413.19	348.99	535.92	1262.77	688.73	457.52	381.40
2009	6936.79	2179.56	363.60	341.93	481.79	1239.29	709.46	486.04	467.54
2010	8395.69	1331.67	388.93	333.48	356.67	1361.90	669.23	479.03	375.44
2011	25784.94	1510.24	473.35	312.45	389.03	1441.49	738.10	404.55	322.46

[a] Costs are reported in real 2011 Danish Kroner. The details of the cost-build up for each generator is described in the relevant chapters.

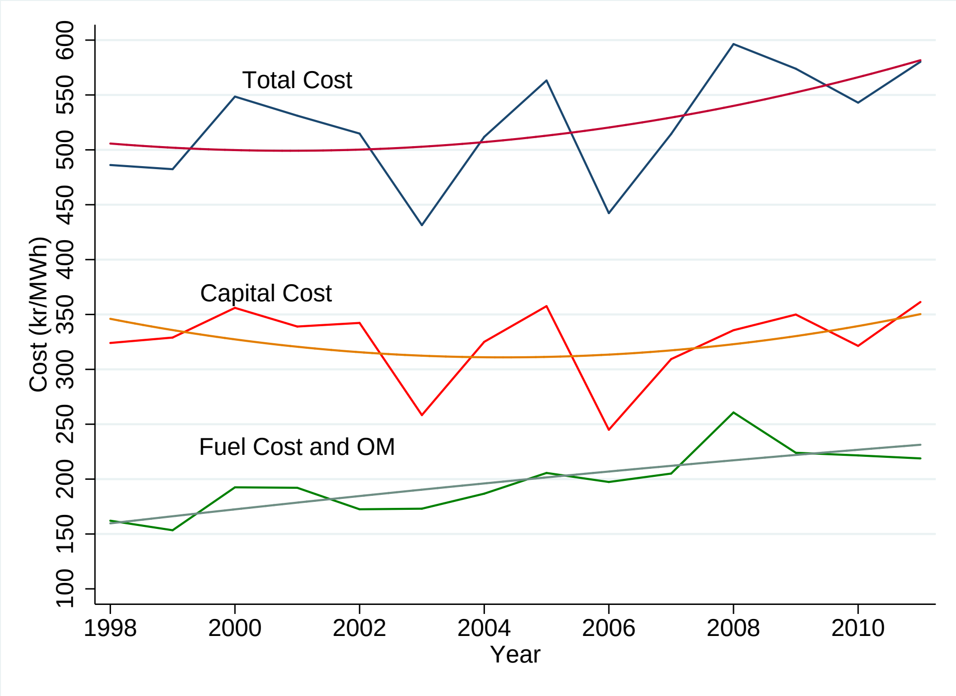


Figure 1.9: Aggregate, Fuel and Capital Costs, 1998-2011

remaining thermal technology types, capital costs show little trend, except for CHP waste for which capital costs declined, which is consistent with an increasing capacity factor. Importantly, capital costs for extraction generators, which is the most important thermal technology (with around one half of the total electricity generation during the period) had little trend over time. Finally, we turn to wind power. The decrease in LCG for wind turbines was primarily driven by falling capital costs.

Fuel costs are reported in table 1.6 for thermal generators (the table does not include wind turbines since they do not use fuel). The main lesson learned is that fuel costs per unit generated increased for all thermal generators because of increasing in fuel prices in global markets. A detailed description of the development in fuel prices is presented in Chapter 5.

The overall impressions of the results are that the increase in fuel costs is important for explaining higher LCG for thermal technologies. In addition, increases in capital costs is also important for explaining higher LCG for some specific thermal generators that experienced declining capacity rates during the period 1998-2011.

1.7.4 Levelised Cost of Electricity

In this section we present the results for the average costs for one MWh produced by Danish generation resources. This is the levelised costs of electricity, LCE. This cost measure is calculated as a weighted average of LCGs with shares of total generation as weights. The overall result is presented figure 1.9 and table 1.7.

It is evident from figure 1.9 that the average unit cost of electricity generation increased over time. The average production costs presented in the figure are production weighted averages - labelled Total cost. The

Table 1.5: Capital Costs, Generation Unit, 1998-2011 (kr/MWh)

Year	Steam Turbine: Condensing	Steam Turbine: Back Pressure	Steam Turbine: Extraction	CHP Waste	Combined Cycle	Gas Turbine	Gas Engine	Land Wind Turbines	Offshore Wind Turbines
1998	765.43	1226.86	367.50	482.44	163.96	560.07	205.69	453.01	742.52
1999	1055.95	1109.53	372.97	407.13	147.21	468.08	210.59	476.59	849.98
2000	765.91	1269.14	414.53	393.34	145.50	519.01	226.59	428.06	2253.78
2001	1276.03	1310.55	364.80	370.29	230.31	519.82	215.36	444.83	681.75
2002	1218.53	1256.98	382.02	371.73	148.84	513.03	220.36	444.77	1091.10
2003	862.30	971.09	318.21	338.22	131.42	470.55	221.66	427.49	444.50
2004	1884.70	1234.24	407.51	420.02	126.30	460.49	214.48	370.29	316.68
2005	2634.87	1165.29	458.32	331.60	140.97	541.92	233.29	376.28	268.36
2006	1016.18	1180.14	299.70	323.75	119.59	515.21	271.59	404.76	285.71
2007	1802.88	1074.16	384.33	332.43	150.18	617.33	365.17	327.56	285.11
2008	2863.17	1189.86	407.88	320.12	147.04	644.59	364.15	360.96	256.38
2009	6279.71	1468.14	379.50	332.27	161.06	756.36	412.82	390.07	343.62
2010	7278.96	940.15	389.59	350.00	132.42	787.08	340.66	383.70	254.04
2011	24172.73	1090.18	452.38	318.62	156.15	884.83	399.31	309.77	201.44

[a] Costs are reported in real 2011 Danish Kroner. The details of the cost-build up for each generator is described in the relevant chapters.

Table 1.6: Fuel Costs, Generation Unit, 1998-2011 (kr/MWh)[a]

Year	Steam Turbine: Condensing	Steam Turbine: Back Pressure	Steam Turbine: Extraction	CHP Waste	Combined Cycle	Gas Turbine	Gas Engine
1998	134.26	400.07	150.96	311.84	387.79	441.10	331.62
1999	124.35	395.65	136.15	306.54	356.86	379.21	301.49
2000	138.22	542.61	162.86	312.67	463.93	538.83	407.66
2001	172.16	566.41	191.13	309.87	445.86	526.83	396.84
2002	136.31	482.34	153.17	325.81	379.82	431.30	331.68
2003	148.32	452.00	155.46	317.97	405.89	467.57	357.38
2004	193.53	503.60	194.51	308.27	402.48	498.83	371.20
2005	227.15	621.64	209.42	306.54	469.46	556.66	415.66
2006	187.25	578.40	194.77	304.48	499.70	617.24	484.98
2007	251.06	606.75	206.31	302.46	546.00	685.74	485.21
2008	389.57	917.54	284.99	324.34	649.95	808.63	534.64
2009	527.76	904.58	238.05	326.18	582.77	661.92	484.14
2010	990.06	584.31	263.69	298.31	501.30	769.56	542.93
2011	1495.59	625.23	290.14	302.53	519.07	762.70	553.94

[a] Costs are reported in real 2011 Danish Kroner. The details of the cost-build up for each generator is described in the relevant chapters.

evolution of overall average production costs over time are illustrated in the figure together with fitted quadratic trend curves to illustrate the trend in average unit production costs. It is clear that costs had been increasing since 2000 with the rate of change increasing over time. There are two factors working on the average unit cost of production that generate the observed changes. First, the costs of generating electricity for a generator could have changed; and second, the generators share of aggregate electricity generation could have changed, i.e., the composition of generation activities across generators or technologies can change. Wind generation provides an interesting example: Generation costs have generally been decreasing for both offshore and onshore turbines since the early 2000s. This effect should lower the contribution to average unit production costs. However, their share of aggregate electricity generation increased which generated a positive effect on the their contributions to aggregate costs. The net-effect of the two opposite effects working on the contribution to LCE turn out to be positive. Therefore, the wind turbines share of aggregate costs had increased over the period, which is evident from table 1.7.

Another interesting characteristic illustrated in figure 1.9 is that there was substantial annual variation in costs. In particular, there were significant drops in costs in 2003 and 2006. These were the result of increases in capacity factors which had the effect of reducing capital costs in these years. There was a substantial drop in electricity imports from Norway and Sweden in these two years prompting an increase in the domestic generation of electricity. Domestic producers utilized their excess capacity to increase electricity generation which lowered average fixed costs resulting in lower average costs of generating a megawatt hour of electricity.

In figure 1.9, we illustrate average unit generation costs together with the major cost components: capital costs as well as fuel and operation and maintenance costs. The cost measures for thermal technologies are net of heat credits.[12] Each series also includes a fitted quadratic curve that illustrates any trend. The figure summarizes well the reasons for the observed changes in average costs over the period. The annual fluctuations were largely driven by changes in capital costs which were primarily caused by changes in capacity factors. Note that beyond the annual variation in capital costs, there was very little long run change in capital costs. In contrast, fuel costs increased over the entire period. The increase in fuel prices was primarily responsible for the increasing trend in aggregate costs. So, the data indicate that capital costs were important determinants of annual fluctuation, but did not contribute to the long run trend of increasing costs. Fuel costs, however, contributed to annual fluctuations, but to a lesser extent compared to capital costs, but was the main factor driving the long run increase in average costs.

The results do not point to increasing average capital costs. The reason for this is twofold. First, overall capital costs of thermal technologies show no trend. Second, we find that the capital costs for wind power fall during the 14 year period, which is evident from figure 1.10. Actually, the capital costs for wind power is about the same level as the corresponding cost for thermal technologies since around 2004. Hence, substitution out of thermal technologies and into wind power took place which kept capital costs down.

Another interesting result is seen from figure 1.11. In this figure we present the average unit costs of generations for thermal technologies and wind power separately. It is evident that electricity generation is relatively expensive for thermal technologies, whereas it is relatively inexpensive wind power. Moreover, the gap between the two unit costs is increasing during the 14 year period. For thermal technologies, the increase is driven by increasing fuel costs, whereas the falling unit cost for wind power is driven by falling capital costs.

The main insight of the figures is that the phasing-in of wind power has not resulted in increasing LGE, as capital costs have no long run trend. Instead increasing LCE is driven by increasing fuel prices.

[12] Calculating heat credits are the solution to the problem of disentangling the costs of generating electricity and the costs of producing heat from total generating costs, which are specific to the class of generators that produce both electricity and heat. Heat credits are essentially the costs that would have obtained if the heat that was produced in the CHP unit was produced by an alternative heating plant, see the discussion of chapter 5.

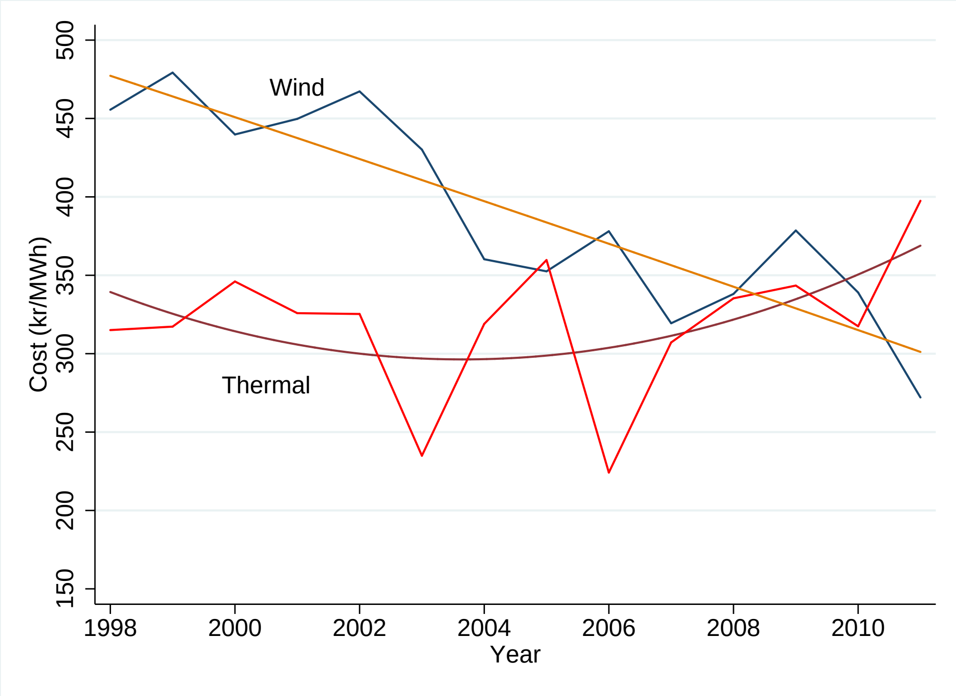


Figure 1.10: Comparison of Capital Costs, 1998-2011

Finally, we present the average unit costs of generation after adjusting for system-wide costs and net-exports in figure 1.12. Since we only have system-wide costs from 2005 and forward, we can only present the costs for the period 2005-2011. It is evident that the adjustment for system-wide costs results in higher per unit production costs of between 20-30 percent. Also it is clear that the adjustment for net-exports do not play a significant role in unit production cost. The explanation for this result is that net-exports were small compared to domestic production. Having said that, it should be kept in mind that the adjusted unit production cost measure is derived using a strong set of assumptions concerning net-exports (see the discussion in Section 1.5.3 above.)

1.7.5 Counterfactual Analysis

Finally, we seek to answer the counterfactual question: "What would generation costs have been in the absence of wind generation?" Of course, this is a difficult question to answer because we have to infer what the Danish power system would have looked like under a no-wind power scenario: The counterfactual is unobservable. In order to infer generation costs under this scenario, we had to make assumptions about electricity generation in the absence of wind power. In particular, we made assumptions concerning the production and allocation of electricity as well as the amount of electricity traded and consumed.

Specifically, we assume that the electricity generated by wind turbines would have been generated by existing Danish thermal generators.[13] The implication of this assumption that each MWh of electricity that was generated by wind turbines must be accounted for by increasing the amount of electricity generated by thermal generators. Also, we assumed that eliminating wind generation does not influence decisions to scrap generators.

[13] We think of this as a "brown technology" mix fully based on fossil fuels for electricity production. An alternative technology mix would be fully based on nuclear power. We do not compare directly to this latter technology but note that Danish Energy Agency (2009) assesses that the LCG for nuclear power in Denmark attains a value equal to wind power for an interest rate of 5 percent, whereas U.S. Energy Information Administration (2014) estimates levelized costs of generation at a value similar to conventional coal and above onshore wind. It should be stressed that these estimates are determined using the standard approach to LCG.

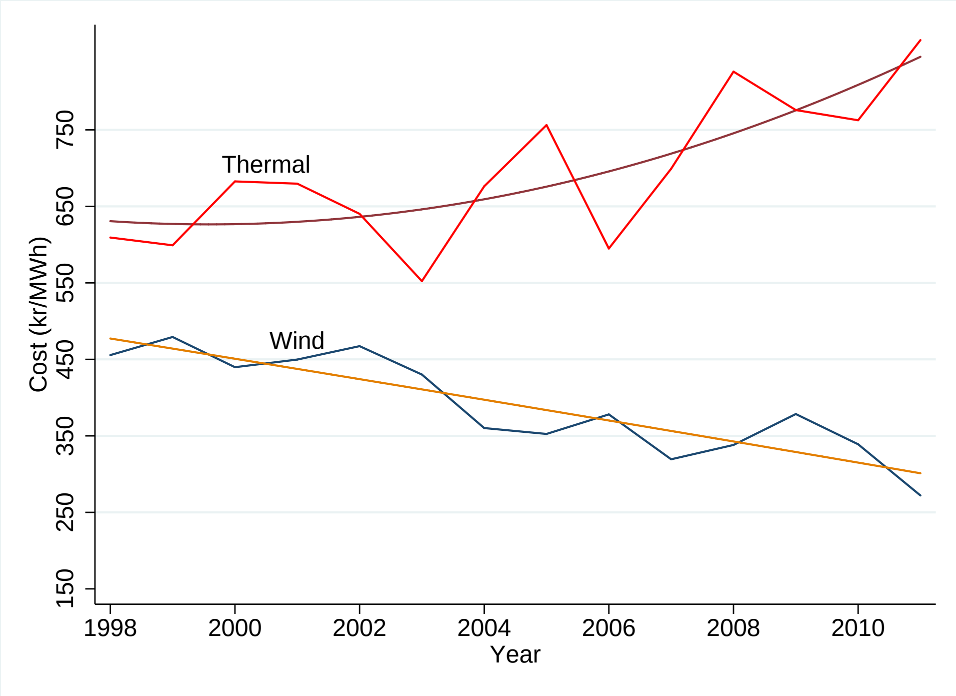


Figure 1.11: Comparison of Average Generation Costs for Thermal and Wind, 1998-2011

Therefore, those generators that were scrapped between 1999 and 2011 remain scrapped.

Next, we deal with the issue of allocating the electricity that was generated by wind turbines to thermal generators operating in Denmark. We assume that the electricity generated by wind turbines are generated by all public power stations including the large central power stations. Moreover, we allocate the electricity produced by wind turbines to the generators, based on the relative production shares of each generator. For example, if a specific generator produced three percent of the total electricity generated by public and central power stations in 2002, then we allocated three percent of the electricity generated by wind in 2002 to this generator.

Using the set of assumptions just described, we recalculated the levelised costs of each generator and weighted them into a new measure of LCE. The new counterfactual measure is reported in figure 1.13. We have also included the realized LCE, capital costs and other costs as presented in figure 1.9 above for comparison. In panel a of the figure, we report the average annual cost of generating a MWh of electricity. The "wind power" series reports the same levelised costs reported in figure 1.9, whereas the other series reports the average cost of generating a MWh of electricity in the absence of wind power. The main result is that average generation costs are lower under the no-wind scenario compared to actual costs. In particular, average annual costs are 13 percent lower under the no-wind scenario relative to the actual costs. The increase in average costs ranged between eight and 16 percent.

In panels b and c of the figure, we report the effect on fuel costs and operation and maintenance cost as well as on capital costs. As in the previous section, the measures are the costs after subtraction of costs attributed to heat credits. As expected, fuel costs are larger in the no-wind case because more coal and natural gas as well as other fuels must be used to generate electricity. Notice that the differences between fuel costs grew in the later part of the period. Capital costs are lower under the no-wind scenario largely due to thermal generators using more of their capacity. Larger capacity factors resulted in lower average fixed costs. The difference in capital costs between the realized scenario and the counterfactual case increased over the period because capacity factors grew larger due to the growing amounts of wind power that needed to be replaced with time.

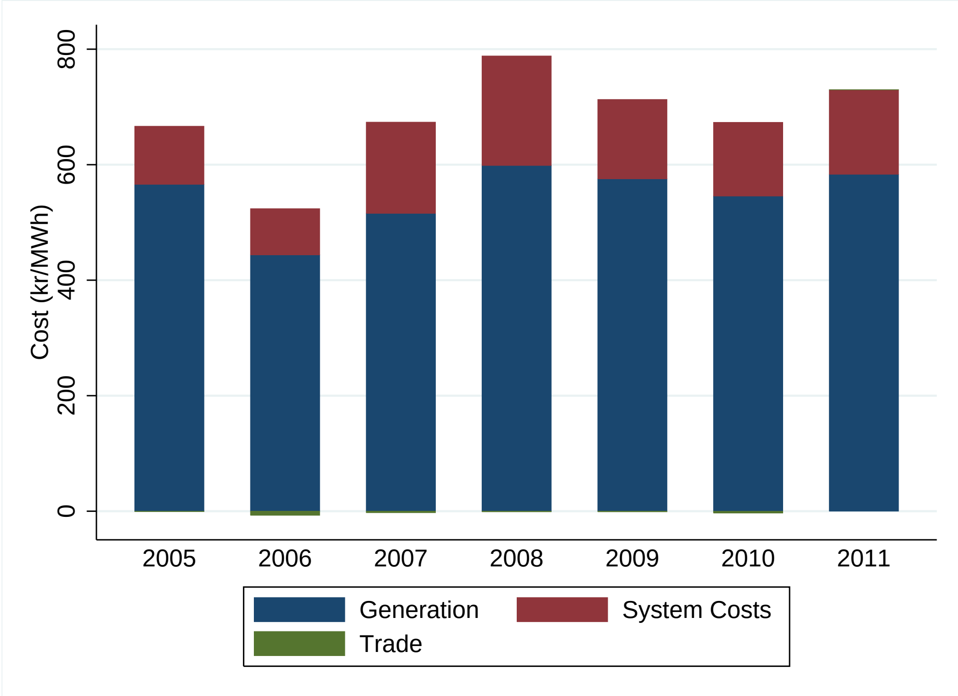


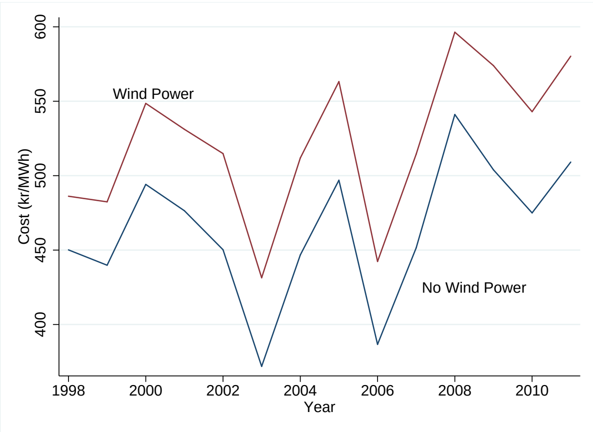
Figure 1.12: Adjusted Costs, 2005-2011

The decrease in capacity costs and the increase in fuel costs results in a slightly increasing average generation cost. On average, total costs decreased by 12 percent with the increase ranging between eight and 14 percent, which is presented in panel d of the figure.

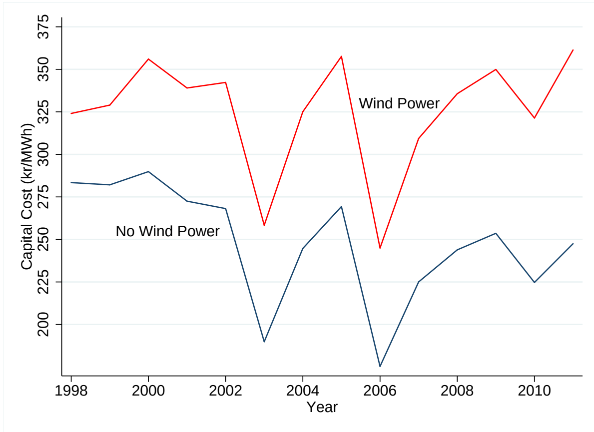
The main insight from the figure is that even though the in-phasing of wind has not changed the average production costs as presented in figure 1.9, Danish electricity generation has operated at relatively low capacity factors for the different technologies. This is clear from the downward shift in costs when generation for public generators increases to more efficient levels, as illustrated in figure 1.13.

1.7.6 Structure of the study

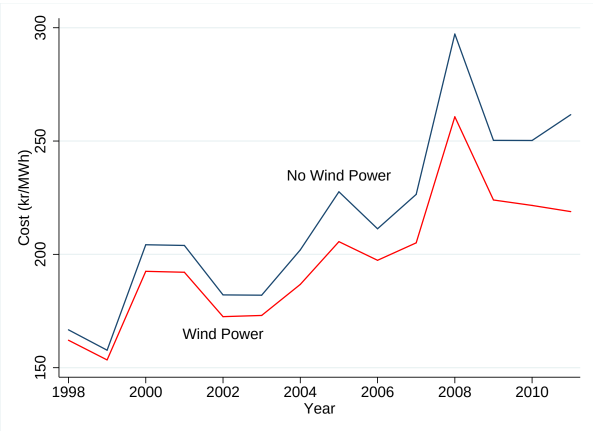
In the following chapters, we present the analysis in detail. The study is organized in two documents each containing multiple chapters. The present document includes six chapters. Chapter 2 introduces and motivates the study, whereas Chapter 3 presents the applied methods. Chapter 4 presents a detailed description of thermal electricity generation technologies used in the Danish power system. Chapter 5 presents results concerning fuel and other costs. Chapter 6 reports the aggregate costs and counterfactual analysis. In the companion paper, Levitt and Sørensen (2014), the data and calculations involved with computing the LCG are described. Specifically, the chapters in Levitt and Sørensen (2014) present detailed cost calculation and analysis broken down by cost types for seven thermal technologies as well as for onshore and offshore wind turbines.



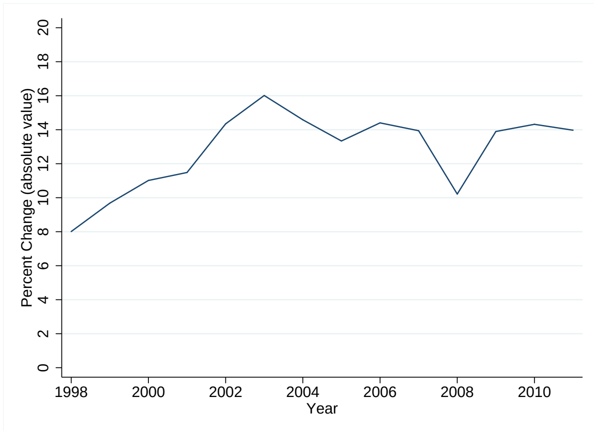
(a) Average Generation Costs



(b) Average Capital Costs



(c) Average Fuel and OM Costs



(d) Percentage Decrease in Total Costs

Figure 1.13: Wind Power Versus No Wind Power, 1998–2011

Table 1.7: Contributions to Aggregate Generation Costs, 1998-2011 (kr/MWh)[a]

Year	Steam Turbine: Condensing	Steam Turbine: Back Pressure	Steam Turbine: Extraction	CHP Waste	Combined Cycle	Gas Turbine	Gas Engine	Land Turbines	Offshore Turbines	Aggregate Cost
1998	100.32	96.98	156.90	9.14	15.69	27.08	40.44	39.07	0.56	486.18
1999	87.22	93.51	163.25	9.42	15.95	27.50	40.05	44.95	0.56	482.40
2000	99.05	97.17	171.44	10.26	22.63	33.79	50.26	62.11	1.83	548.55
2001	89.59	92.40	165.39	9.76	29.39	31.98	49.20	61.49	1.95	531.15
2002	84.65	95.32	150.78	9.63	32.11	27.60	43.93	65.51	5.31	514.83
2003	55.74	78.41	129.90	8.03	31.75	24.59	38.39	53.65	10.94	431.40
2004	57.34	86.64	171.05	10.29	35.01	30.61	44.67	62.56	13.65	511.83
2005	63.31	89.14	189.40	11.26	41.07	34.21	50.74	68.10	15.98	563.21
2006	58.11	68.61	130.84	9.23	40.10	29.31	41.25	52.48	12.40	442.34
2007	60.87	67.51	174.74	11.32	45.61	31.40	45.64	62.90	14.45	514.44
2008	64.02	82.58	204.46	12.97	57.40	37.80	52.31	68.81	16.04	596.38
2009	54.59	95.91	194.17	12.30	47.33	31.76	48.22	68.07	21.56	573.93
2010	53.47	76.05	189.19	10.69	40.49	31.47	51.44	63.88	26.31	542.98
2011	54.55	81.65	201.87	11.79	40.79	32.42	51.47	74.17	31.54	580.25

[a] Costs are reported in real 2011 Danish Kroner.

Chapter 2

Introduction

2.1 Power Systems

Electricity that is delivered to end-users is really a bundle of many different services. The main services are generation, transmission, distribution, frequency control and voltage support. The services most recognizable by the general public are generation, transmission and distribution. Generation produces the power and then the transmission system carries the power from the power station to the load centers while the distribution system then delivers the power to consumers. Perhaps less well known by the general public are the services required to maintain power quality and reliability on the grid. Frequency control and voltage support ensures that there are no disruptions to the power grid. Of course, each of these services themselves involve their own complex set of production processes. A power system is the collection of the generation, transmission, distribution and reliability services together with their downstream production processes. The subject of this book is the Danish power system. In particular, the main objective is to study the costs associated with generating electricity. We also undertake a brief analysis of the costs of running and maintaining the distribution and transmission grid as well as the costs of ensuring a stable and secure supply of electricity. Determining the costs of generating and delivering electricity is not an easy task. Power systems are complex systems consisting of many heterogenous participants all interacting in complicated ways. There are also practical considerations. The study involves collecting and analyzing a large amount of data. There are clearly limits on the availability and quality of some data.[1] A common theme throughout this book, given the complexity of Denmark's power system, combined with the practical limitations that often exist with large empirical studies, is the existence of a certain degree of uncertainty with some of the computations in the book.

Power systems are complex for a variety of reasons. Producing electricity from an energy source, be it from renewable sources like wind or hydro, or from nonrenewable thermal fuels like coal or natural gas, and then distributing the electricity to final users is a complicated process involving a diverse set of interdependent participants and institutions. When thinking about the complexity of a power system it is useful to classify the complexities into three interrelated levels: international factors, macro factors and micro factors.

International trade has a substantial influence on the Danish power system. International trade of goods and services is pervasive both in the power generation sector as well as in the wholesale electricity market. International trade involving energy commodities (coal, oil or natural gas) are determined primarily by the domestic endowments of the commodity together with demand and domestic supply. Coal is the primary fuel

[1] Firms are generally reluctant to share or make public information concerning their costs of production. The study uses detailed production data at the level of the individual generators. These data were provided under the condition that data on individual generators not be made public nor could the attributes of individual generators or small group of generators be identified.

used in thermal generators in Denmark. Virtually all of the coal used for generating electricity is imported because Denmark does not have a domestic supply of coal. A power station must deal with a number of issues when importing coal or other fuels. These include the price of coal, shipping costs, stability and reliability of supply, consistent and timely deliveries as well as transactions costs associated with negotiating and writing contracts. In contrast, Denmark is endowed with large deposits of natural gas and so relies less on imports relative to coal. Shocks to the price of energy commodities can have significant effects on costs. International trade is not restricted to energy commodities. Power systems are also influenced by trade in technology and human resources as well as trade in financial services. In addition, Denmark also imports and exports electricity.

International institutions also influence the Danish power system through various regulations which can either be binding (legal requirements) or non-binding (best-practice policies). Participating in international legal frameworks as well as treaties and conventions with other countries and with international organizations often requires that constituent members of a power system operate under a set of regulations. Perhaps the most visible international organization having important implications for Denmark's power system is the European Union. An important institution developed within the European Union is the Emission Trading System. The European Union Emissions Trading System (EU ETS) is a cap and trade system that was established to reduce the harmful green house gases emitted by power stations and large manufacturing plants.[2] The are a number of rules and procedures associated with the EU ETS under which Danish power stations must operate. These regulations have increased the costs of generating electricity. The EU ETS regulates over 11 thousand power stations and manufacturing plants in the 28 EU member states as well as Iceland, Liechtenstein and Norway. The EU ETS is a cap and trade system which means that the overall volume of greenhouse gases that can be emitted each year is subject to a cap set at the European Union level. The cap is enforced by requiring plants that emit greenhouse gases own emission allowances. Emission allowances are the currency of the EU ETS. Each allowance gives the holder the right to emit one tonne of CO_2. Emissions allowances can only be used once. Power stations receive or buy emissions allowances which they trade. The costs of emissions allowances are studied in Chapter 5.

The Danish energy sector is also heavily influenced by aggregate economic activity and national level institutions (macro level effects). The energy sector plays a vital role in any economy because of the mutual interdependence between economic activities and energy. The energy sector uses inputs from various sectors including manufacturing, transport and households, among others, to produce and deliver electricity. Moreover, energy is a key input for manufacturing sectors as well as for services and households. These interrelations partly determine the demand for electricity which then influences both short run and long run investment decisions. Power systems are influenced by aggregate economic activity.

Given the importance of the energy sector in the Danish economy, national level institutions tend to both influence and get influenced by the energy sector. The Danish government has played an active role in the energy sector. Governments and regulators set policies and impose regulations including various forms of taxes or subsidies, environmental regulations, safety standards, among others, under which power stations must operate. These regulations directly influence the power system in a variety of different ways because they affect production and investment decisions of power stations as well as consumption decisions made by consumers.

The final group of factors is the energy sector itself (micro level effects). The energy sector is composed of different interrelated industries. Transmission system operators, power stations and consumers interact in a system of complicated markets designed to ensure stable, secure and efficient power supply. Their are various

[2] A cap and trade system means that the overall volume of greenhouse gases that can be emitted each year is subject to a cap. The cap is enforced by requiring plants that emit greenhouse gases own emission allowances. Emission allowances are the currency of the EU ETS. Each allowance gives the holder the right to emit one tonne of CO_2. Emissions allowances can only be used once. Power stations receive or buy emissions allowances which they trade.

types of markets as well as market participants: capacity markets, wholesale markets, futures markets as well as various commodity markets, to name a few.

There is a great deal of complexity even at the level of the power stations. The stability and reliability of a power system depends on many different power stations, operating independently, to combine to continuously meet changing power demands. There are many different ways to generate electricity using a variety of different thermal fuels or renewable sources such as wind and hydro. Each type of generating technology has different production characteristics that must work together within the power system to ensure a stable and secure supply of electricity. A couple of examples help illustrate the complexity. Wind energy is an intermittent source of electricity. Electricity can be generated only when there is wind (or winds are not too strong). Intermittency of wind energy has system-wide implications: In order to maintain a secure supply of electricity, reliable backup generation must be made available. Similarly, for power systems to be stable, the mix of generators must be able to supply base-load demand, mid-load demand as well as peak-load demand. Peak-load generators typically have different production profiles than base-load generators. Peak-load generators have quick start capabilities and can be started or shutdown relatively quickly and less costly relative to base-load generators. A mixture of different types of generation plants with varying degrees of responsiveness to changes in demand and supply (wind conditions) is needed to ensure system-wide stability.

2.2 Introduction to the Danish Power System

2.2.1 Generation

Since electricity is a fundamental input into the economic activity of the rest of the economy, both for industry and households, efficient electricity generation is important. Moreover, a stable and secure supply of electricity is a necessary requirement of an efficient power system. Electricity is generated in Denmark using a number of different technologies. In this book, we distinguish nine different technologies: Seven thermal technologies as well as offshore and onshore wind turbines. The seven thermal technologies are:

1. condensing generators;
2. back-pressure generators;
3. extraction generators;
4. combined-cycle generators;
5. gas turbines;
6. combined heat-and-power (CHP) waste;
7. gas engines.

There has also been small-scale solar generation as well as electricity generated from hydro resources. Electricity generated from hydro has been decreasing since at least 1999, whereas solar produced electricity has been increasing in recent years, although solar generation remains an insignificant source of electricity in the Danish power system.

Thermal generators are classified as being either conventional, meaning they only produce electricity, or classified as combined heat-and-power generators, which generate both heat and electricity simultaneously. Studying how generation costs evolved over time given the interaction between conventional thermal generators, CHP generators, and wind turbines is an important objective of our study.

2.2.2 Transmission and Distribution

The Danish electricity grid consists of the transmission and distribution network. The transmission grid is a network of heavy electrical cables through which electricity is transported laterally and longitudinally over

Denmark. In addition, the transmission grid is also used for the exchange of electricity with neighboring countries. Electricity is transported from the transmission grid to final consumers, households, firms and businesses, through the distribution network. The institution charged with running these networks is typically called a Transmission Systems Operator (TSO). In Denmark, the TSO is an independent, state-owned firm called *Energinet.dk*. *Energinet.dk* was established in December 2004 by a merger between a number of Danish Power firms including *Eltra*, *Elkraft Systems*, *Elkraft Transmission*, and *Gastra*. The effective operation date was January 2005.

For the purpose of our cost study, we focus on two important functions of *Energinet.dk*. Broadly defined, these two function are:

1. maintain system security and adequacy;
2. develop and maintain the Danish electricity transmission infrastructure.

Because we are mainly interested in the production costs of generating and distributing electricity we do not consider some other costs of*Energinet.dk*: Some of these other costs include subsidies to renewable generation or expenditures on research and development.[3]

The main focus of this book is to examine the evolution of generation costs given the transformation of the Danish power system. However, a brief analysis of the costs of system-wide costs illustrates the overall scale of the costs of the Danish power system as well as emphasizing the scale of generating costs.

2.2.3 Trade

The electricity generated in Denmark is both consumed domestically as well as exported for use in other countries. Moreover, the electricity that is consumed in Denmark is not entirely generated domestically. Importantly, the Danish power system is interconnected to power systems in Norway, Sweden and Germany. The transmission grid and interconnections over which electricity is delivered and exchanged are owned and operated by *Energinet.DK*.

The transmission grid in Eastern Denmark is connected to Sweden with two high voltage cables ($400Kv$ each) and two low voltage cables ($132Kv$ each). The export capacity from eastern Denmark to Sweden is approximately 1700 MW, whereas the import capacity is 1300 MW. Eastern Denmark is also connected to Germany. The transmission capacity between Germany and Eastern Denmark is 600 MW. Western Denmark is also connected to Sweden and Germany. The exporting capacity to Sweden from Western Denmark is around 740 MW, whereas the export capacity to Germany is 1700 MW. In addition to the interconnections with Sweden and Germany, Western Denmark is interconnected with Norway. The export capacity from Western Denmark to Norway is about 1500 MW. Finally, there is a low voltage connection between Sweden and Bornholm which has an export capacity of only 60 MW. We provide a brief analysis of the revenue earned from the Danish export of electricity to Norway, Germany and Sweden.

2.3 What Costs?

Because generating electricity is a complicated process it is important to be clear about what we are studying and the costs we measure. Our objective is to measure the average cost of generating a megawatt hour of electricity. Specifically, we construct a physically accurate model of electricity generation technologies in Denmark to derive estimates of the costs of each generation technology. That is, we map actual costs to the generation of a MWh of

[3]In addition, *Energinet.dk* is also tasked with running the Danish natural gas distribution system. We of course, do not include the costs associated with the distribution of natural gas.

electricity for each generator in the Danish power system. A physically accurate model of electricity generation involves calculating

1. Fuel prices;
2. Transportation costs;
3. fuel energy density;
4. thermal efficiency;
5. plant construction costs;
6. interest rates and depreciation costs;
7. capacity factors;
8. operation and maintenance costs.

To improve the accuracy of our cost estimates, we calculated costs at the level of the thermal generator or wind turbine. Focusing on the individual units means that we can assign unobserved costs conditional on the characteristics of the specific generator. For example, we assign overnight costs (to be described shortly) to each generator based on the type and vintage of the generator as well as its thermal capacity and types of fuel the unit burns. Even within a single class of generator, combined-cycle gas turbines, for example, costs vary based on vintage and capacity. Moreover, generators, even those in the same class, burn a variety of different fuels, or have vastly different capacity factors. Because the assets we analyze are specific generating units and not classes of generators, we can account for differences between individual generators, which we observe in our data, in our cost calculations.

2.4 Why Study the Costs of Producing Electricity?

The objectives of this book are ambitious and the tasks to be accomplished to meet the objectives are not without their difficulties. However, the study is important. Energy plays a vital role in the Danish economy. Indeed, energy is of fundamental importance in any economy. Energy is a key input to the production process that transforms inputs into goods and services. Electricity is also vital to the everyday workings of Danish households. Consequently, energy policy and management practices in the energy sector can have significant influences on the macro economy as well as on individual Danish households. Understanding the costs of producing electricity is important for evaluating existing energy policy and for guiding the development of future energy policy.

An important contribution of the research presented in this book is a study of the costs of generating electricity, built up from the individual generators, and how these costs have changed over time given the significant changes that have occurred in generation in Denmark over the past few years. One interesting change that has occurred has been the increasing penetration rates of wind energy and other sources of renewable energy sources. How has this structural change affected aggregate generation costs? The study can also inform the management of the energy sector. For example, understanding how price shocks to energy commodities influence costs can help inform potential strategies designed to mitigate the affect of price shocks on system costs.

Chapter 3

Methods

3.1 Introduction

In this chapter, we describe the methods we used to calculate the costs of generating electricity in the Danish power system. We begin with a brief overview which provides the opportunity to introduce and define important terms that are commonly used in the electricity sector and which we use throughout this study. We also introduce and describe the many calculations involved in computing the levelised cost of generating electricity. Moreover, any cost model of a complicated production process consisting of many heterogenous units, like the power sector, necessarily involves making simplifying assumptions. There are a number of reasons why our calculations required simplifying assumptions. Two of the most important reasons are:

1. producing and delivering electricity is an extremely complicated process involving many downstream and upstream participants;
2. there exists limitations both on the availability of data as well as on the quality of data that is available.

Interpreting the results of the model requires a good understanding of the assumptions we make and their potential effects on the results. Consequently, in this chapter, we also discuss some of the assumptions involved in our calculations.

We also use this opportunity to discuss the complications and uncertainties that naturally arise when calculating the costs associated with a complicated production process. To facilitate an understanding of the cost model, a simplified example is provided that highlights the important features of the model and demonstrates many of the calculations. We use the example to introduce some of the assumptions of the model and discuss the sensitivity of the results to these various assumptions.

We compute the levelised cost of generation at the generator level. We used the best available data to compute the LCG in the Danish power system; however, uncertainty still arises in the analysis because not all of the costs are directly observable. In particular, we do not observe actual procurement and construction costs (overnight costs) for each of the generators. What we do have are good approximations to these costs which are conditional on different attributes of the generators (technology, vintage, capacity and fuel). The fact that we have access to data on each generator in the Danish power system means that we can assign costs based on the characteristics of the specific generators. We do, however, directly observe key cost components including efficiency rates, fuel consumption, fuel costs, and capacity rates.

Although the main objective of this study is to calculate generation costs, we do calculate system-wide costs and an aggregate measure of the costs of the electricity consumed in Denmark. System-wide costs account for all the costs associated with delivering electricity to the end-users. These costs include, for example, the costs of building and running distribution networks, supply adminstration, network losses, and the supply of ancillary services among others (see chapter 6). In the remaining part of this chapter we document the assumptions and methods we used to calculate the levelised cost of generating electricity.

3.2 Levelised Cost of Generation Unit

3.2.1 Overview

The cost model is based on the physical production of electricity. That is, we map actual costs to the generation of a MWh of electricity for each generator in the Danish power system. The power system in Denmark consists of a heterogenous set of technologies that produce only electricity or both heat and electricity in a cogeneration process. These technologies includes a variety of different types of thermal generators as well as onshore and offshore wind turbines. A small amount of solar and hydro power also exists in the Danish power system. Although, hydro power has been a declining source of electricity in Denmark for a number of years; however, solar power could play a significant role in the near future. Given the limited role of solar and hydro, we focus our analysis on thermal generators as well as on offshore and onshore wind turbines.

Conventional thermal generation involves a wide variety of different generators including a large number of cogeneration units which produce both heat and electricity. We study seven different classes of thermal generators: condensing, back-pressure, extraction, combined-cycle gas turbines, single-cycle gas turbines (gas turbines), CHP waste and gas engines. Because Danish electricity is generated using a heterogenous set of generators, it is important for accuracy, that costs are constructed for each generation unit. Working at the level of the generator provides better opportunity to account for differences in costs across generators. Fortunately, we have access to data at the individual generator level. Therefore, we calculate costs for each generating unit and then aggregate up to get an aggregate average per unit cost.

The model is based on calculating the levelised cost of generating electricity at the generator level (LCG). LCG is the lifetime discounted cost of using a generation asset which is converted into an equivalent per unit cost of generating electricity. Specifically, the cost per unit of generation is kroner per megawatt hour or kr/MWh.[1] There are three broad issues which together determine the scope of the cost analysis: first, the asset must be specifically defined; second, the cost burden must be defined; third, decisions concerning time must be made. We discuss each of these in turn.

The first step in calculating the LCG in a power system is to define the generation asset. To improve the accuracy of our cost estimates, we calculated costs at the level of the thermal generator or wind turbine. Focusing on the individual units means that we can assign unobserved costs conditional on the characteristics of the specific generator. For example, we assign overnight costs (to be described shortly) to each generator based on the type and vintage of the generator as well as its thermal capacity and types of fuel the unit burns. Even within a single class of generator, combined-cycle gas turbines, for example, costs vary based on vintage and capacity. Moreover, generators, even those in the same class, burn a variety of different fuels, or have vastly different capacity factors. Because the asset we analyze are specific generating units and not classes of generators, we can account for these differences, which are observable in our data, in our cost calculations.

Determining the cost burden follows naturally from the definition of the asset. The cost burden is the answer to the question: Whose costs are we calculating? Another way to ask this question is: What is the scope of the costs? We calculate the costs borne only by the owner of the asset in relation to the operation of the unit. This means that at the level of the asset, we do not include reserve or balancing costs, taxes or subsidies, or other

[1] LCG is also called the life-cycle cost because it covers all cost starting with the initial ivestment up to decommissioning.

system wide costs. Moreover, we do not consider the environmental or social costs of the plant's construction or externalities arising from the plant's operation. However, we do include the costs of carbon emissions which is internalized thought carbon prices. We do not include any other environmental tax or subsidy.

The final broad issue is time which involves two question. First, what is the relevant life-span of the generation asset? The life-span of the asset is important because it determines the period over which costs are spread. Installing a generation unit involves large fixed setup costs. The longer is the lifespan of the unit, the smaller the annual payments to the fixed costs will be. Life-span of the asset depends largely on the type of technology. The second question concerns the period in which the initial investment in the asset was made. The date of the ordering of the plant normally locks in a large part of the capital costs.

With the scope of the analysis determined, we can turn to introducing the actual components of the LCG. There are two main categories of costs: the cost of capacity and variable operating costs. Capacity costs involves two components: The capital costs of bringing the asset into operation; and, second, the fixed costs of keeping the plant available to generate electricity. The capital costs of bringing the asset into operation is often called overnight costs. Our overnight costs include procurement and construction costs of the technology (plant and equipment costs). Overnight costs do not include transaction costs: insurance costs or the costs of project management, approvals or administration. We also do not include the costs of renting or procuring land (whether explicit or implicit). Unfortunately, we cannot include these costs because we do not have the data from which to calculate them. Importantly, overnight costs vary across the different types of generators as well as by vintage, capacity and the types of fuel the unit burns. Given that we have access to data on individual generators, we assign overnight costs based to each generator based on these characteristics.

The fixed costs of keeping the plant available to generate electricity refers to fixed operating expenses. These costs are independent of how the plant is operated and include labour costs, planned maintenance costs, and various administrative costs. These costs also include planned reinvestment costs within the stated lifetime of the plant. Again, fixed operating costs vary across generators depending on their different attributes. We assign fixed operating costs conditional on the attributes of each generator.

Variable operation costs include costs that depend on use. These include variable operation and maintenance costs, fuel costs, and carbon payments. Operation and maintenance costs include consumption of auxiliary materials (not fuels) and the costs of unscheduled repairs (including parts). Carbon payments are the expenditures on purchasing carbon emission permits. We calculate fuel costs using the burner-tip principle. The burner-tip costs includes the price of the fuel, transportation and insurance costs of getting the fuel to the generator as well as the heat content of the fuel (the efficiency of the fuel).

In the next few sections we describe the calculations involved for each of the cost components we just introduced. In the final section of this chapter, we provide an example of a cost build-up for a hypothetical generator.

3.2.2 Capital Costs

In this section, we describe the calculation involved with calculating capital costs. Generating capacity is the size of a generator and is measured by the maximum flow of power it can produce. Typically, capacity is measured in kilowatts (KW) or megawatts (MW).[2] The cost of capital are reported in kr/MW. Interpretation of this cost is important: This is the cost of the flow of capacity produced by a generator over its lifetime.[3] Capital

[2] For example, a combined-cycle gas turbine with extraction technology typically has a capacity of 400 MW, whereas small scale generators like the single-cycle gas turbine have a capacity of about 50 MW.

[3] A coal plant with an overnight costs of $kr1,000/KW$ does not cost $kr1,000/KWy$. This would imply a plant life of one year and a discount rate of zero.

costs need to be levelised so that they can be correctly compared to other costs.[4] Specifically, pricing capacity requires using a capital recovery factor to levelise the cost of capacity over the lifetime of the generator. A capital recovery factor is the ratio of a constant annuity to the present value of receiving that annuity for a given length of time (the life of the generator). For a given interest rate equal to r, the capital recovery factor is defined as

$$CRF = \frac{r(1+r)^T}{[(1+r)^T]-1} \tag{3.1}$$

where T is the life of the plant in years. Using the capital recovery factor to levelise capital costs amortizes the investment cost over the lifetime of the generator. Note that the units for the fixed annual payments to capacity are kr/kWy. The units can be converted to the more standard kr/MWh by dividing by 8.76.

Example: The capital recovery factor for a generator with a lifetime of $T = 40$ years and an interest rate $r = 0.1$ is

$$CRF = \frac{0.1(1+0.1)^{40}}{[(1+0.1)^{40}]-1} = 0.1022.$$

Suppose that the overnight costs of the generator is $kr5000/kW$. Then the amortized fixed cost is

$$FC = kr5000/kW \times 0.1022 = kr511/kWy.$$

Therefore, the annual fixed cost to capacity is $kr511/kWy$ or $kr58.33/MWh$.

A natural interpretation of these payments to capital is to think of them as rental rates. A 300 MW generator delivers a 300 MW flow of capacity for some unspecified period of time. This flow of capacity must be paid for by a flow of money, krx/h. If the generator's capacity is rented for one hour then the available capacity is 300 MW for one hour. The rental cost of the generator is krx/h per 300MW. Scaling the rental cost by the capacity of the generator results in the standard measure kr/Mwh.

Perhaps the most important determinant of capital costs is the capacity factor because it defines the amount of the fixed costs that is distributed across output. We have already alluded to the importance of capacity factors in chapter 1.[5] The capacity factor, denoted by (cf), measures the utilization rate of a generator's capacity. In particular, the capacity factor is the ratio of electricity dispatched from the generator to the generator's potential production. A specific generator's capacity factor in year t is calculated directly from production data:

$$cf_t = \frac{MWh \text{ production}_t}{MW \text{ capacity} \times 8760 \text{ hours}}. \tag{3.2}$$

Capital costs entail large fixed costs which make capacity factors an important determinant of the cost of capacity per megawatt hour of generation. The higher the capacity factor, the more fixed costs get smeared across revenue generating output. The lower the capacity factor, the more capacity of the generator sits idle. Low utilization rates of a generator's capacity increases the per unit costs of generation. The levelised costs of capital are adjusted by each generators capacity factor to get the cost of capacity per unit of generation. An example of how capacity factors can affect capital costs is provided in an example box.

The levelised costs of capital per unit of generation is calculated for each generator using the formulae

$$lcc = \frac{oc \times CRF}{cf}.$$

[4]Other costs are measured in terms of money per unit of power. We will measure the costs in units kr/MWh or kr/kWh which is the cost of one megawatt (or kilowatt) of energy utilized for one hour. It is impossible to compare costs measured in kr/MW to costs measured in kr/MWh.

[5]Additional analysis concerning capacity factors is proved in Levitt and Sørensen (2014).

where oc denotes the overnight costs, CRF denotes the capital recovery factor defined in equation (3.1) and cf denotes the capacity factor defined in equation (3.2).

Example: Continuing from the previous example in which the amortized fixed cost was calculated to be

$$FC = kr5000/kW \times 0.1022 = kr511/kWy.$$

Suppose the capacity factor for the generator was 35% in 2010 and 25% in 2011. The cost of capacity per unit of dispatched electricity for this generator in 2010 and 2011 was

$$cc_{2010} = 166.66 \text{ and } cc_{2011} = 233.32.$$

3.2.3 Fuel Costs

There are four important determinants of aggregate fuel costs:

1. The actual price of the fuel (p_{ft}).
2. The transportation costs of getting the fuel to the generator (s_{ft}).
3. The heat content of the fuel (also referred to as energy density)(ρ_{ft}).
4. The heat rate of the generator or generating technology (η_{ft}). Heat rates are typically reported as percentages or rates.[6]

The price of a specific fuel f, in period t, which we denote by p_{ft}, depends on the type of fuel as well as the quality of a specific fuel type. For example, oil, coal and natural gas all have different prices as well as varying price dynamics. Each of these commodities have related but distinct markets. In addition, each type of fuel (coal, oil or natural gas) can be of varying quality. The different qualities will each have a different price. What is important for generating electricity if the heat content of the fuel. That is, the quality of a fuel is essentially measured by its heat content. The heat content of a fuel, which we denote by ρ_{ft}, is the potential energy in the fuel that can be converted to heat. Higher quality fuels typically have higher heat content. Of course, the quality of a fuel can also depend on characteristics other than heat content. For example, coal with a low sulphur rating is relatively more costly than high sulfur coal but still may be used in order to satisfy environmental regulations concerning emissions.

The costs of transporting fuels from their source to the generators is a significant component of fuel costs. Transportation costs can be quite different across fuels. For example, Denmark imports all of its coal, whereas it produces almost all of the natural gas used for generating electricity. Coal is bulky and cannot be shipped through pipelines. The costs of transporting coal from mine to the generator can be significant. In contrast, Denmark produces its own natural gas as well as imports (since 2010) and exports natural gas. Moreover, natural gas can be shipped through pipelines which is less costly than rail or ocean shipping and then rail. The bottom line is that natural gas is less costly to transport relative to coal.

The heat rate of a generator measures the thermal efficiency of the plant. Thermal efficiency accounts for every effect which causes energy losses between the input of fuel and the busbar of the plant.[7] This is a broad measure of the thermal efficiency of a generator in the conversion of fuel into electricity. It measures the amount of heat input in kj per hour for each KWh of electricity produced. Thermal efficiency is discussed extensively in the context of the individual generating technologies.

[6] An example of how heats rates are obtained is provided. If a generator produced $779,601 MWh$ of electricity in a given year and consumed $9,245,580 MMBTU$ of fuel, then the heat rate is $11.85937 MMBTU/MWh$ or $11,859.37 Btu/kwh$. To express the efficiency of a generator or power plant as a percentage, divide the equivalent Btu content of a Kwh of electricity (which is $3,412$) by the heat rate. The heat rate of $11,859.37 Btu/kwh$ is equal to an efficiency rate of 28.77 percent or 0.2877.

[7] A generators's busbar is the point beyond the generator by prior to the voltage transformation point.

Accounting for each determinant of aggregate fuel cost gives the following equation for calculating aggregate fuel costs:

$$F_{ft} = \left(\frac{p_{ft} + s_{ft}}{\rho_{ft} \times \eta_{ft}}\right) \tag{3.3}$$

which gives the fuel costs in DKK/KWh.[8]

Example: Consider a price of coal equal to $kr340/Tonne$. This price includes the cost of coal plus freight and insurance. The energy density of the coal imported at this price was $\rho_{ft} = 6.99MWh/Tonne$. The generator's thermal efficiency while burning this fuel was 0.38. The burner tip costs are then

$$F = \frac{340}{6.99 \times 0.38} = kr96.85/MWh.$$

3.2.4 Additional Costs

Operation and maintenance costs (OM) are generally less important in terms of contributing to aggregate costs relative to capital and fuel costs. Operations and maintenance costs are classified into two categories: fixed operations and maintenance costs and variable operations and maintenance costs. Fixed OM costs are measured in costs per MW of capacity, whereas variable OM is measured in costs per MWh gross generation.

Generators also incur environmental costs. The are two main environmental costs. First, generators must install pollution control equipment. These installation costs are included in the construction costs. The requirement for generators to install pollution control equipment is often suggested as the reason why there have been periods in which overnight costs increased quite substantially. See for example Joskow and Rose (1985) and McNerney et al. (2011). Second, since 2005, generators are required to purchase the right to emit carbon into the atmosphere. Generators must buy a permit for each tonne of carbon emitted into the atmosphere while generating electricity. Permits are traded in a market.

Permit costs are calculated using the spot market price for carbon permits together with the amount of fuel used for generating electricity and the emissions factors for each type of fuel. We calculate expenditures on carbon, CC_{gt}, for generator g in year t using

$$CC_{gt} = e_{gf} \times F_{gt} \times PC_t$$

where e_{gf} is the emission rate for a specific type of generator, g, burning fuel f; F_{gt} is the fuel burned by the generator in year t (this may include more than one type of fuel); PC_t is the price of carbon.

Example: Consider a thermal generator with capacity greater than $300MW$ burning coal. The emission factor for a generator with these characteristics is $e_{gf} = 94.73kg/GJ$ or $e_{gf} = 0.027Tonnes/MWh$. Suppose that the price of a permit is $PM_t = kr155/Tonne$. Then the carbon price for the generator is

$$e_{gf} \times PM_t = 0.027Tonnes/MWh \times kr155/Tonne = kr4.19/MWh.$$

In addition, suppose that the generator produced $100GWh$ of electricity during the year. Total expenditure on carbon emissions for this generator is $kr419,000$.

[8] It is important that the units are consistent throughout the study so that we can always calculate aggregate measures as well as compare costs. The units should always be in ($\$/KWh$), ($\$/MWh$) or ($\$/GWh$). For example, given the price of coal and the cost of transportation, both measured in $kr/tonne$, and the heat content of coal, which is measured in ($kWh/tonne$), then the expression in the brackets in equation (3.3) in term of the units is

$$\frac{\frac{kr}{tonne} + \frac{kr}{tonne}}{\frac{kWh}{tonne}} = \frac{kr}{kWh} = kr/kWh.$$

3.3 Examples of Cost Calculations

In this section, we provide an example of the calculations and corresponding assumptions required for calculating the costs of a hypothetical single generator or wind turbine. Each of the different cost components are carefully explained. We provide an example that mimics the different calculations and assumptions that are involved with calculating the costs of a typical thermal generators.[9] Consider a steam turbine condensing generator that has used two different fuels: coal and heavy fuel oil. For this example, assume that the generator was constructed in 1970 and scrapped in 2011. The overnight costs of this generator is $kr5590/kW$ or 5.59 million kr/MW. The interest rate is equal to six percent. Finally, assume that this generator delivered 10 percent of the total aggregate amount of electricity generated in Denmark between 1998 and 2002; 5 percent between 2003 and 2007; 1 percent between 2008 and 2010.

We first consider capital costs. The breakdown of capital costs are presented in table 3.1. The two key components of capital costs are initial investment costs or overnight costs and the capacity factor. Overnight costs will be taken from various external sources (we discuss sources in Levitt and Sørensen (2014)). The overnight cost for this generator is $kr5590/kW$ or 5.59 million kr/MW. Given that the interest rate is six percent and the generator's lifetime is 31 years the capital recovery factor is 0.07 (reported in column 2). The fixed annual cost is $kr401.32/kWy$ or $kr45.81/MWh$.

Table 3.1: Capacity Costs

Year	Capital Recovery Factor	Fixed Cost (kr/kWy)	Fixed Cost (kr/MWh)	Capacity Factor (%)	Cost of Capital (kr/MWh)
1998	0.07	401.32	45.81	0.46	98.55
1999	0.07	401.32	45.81	0.09	495.79
2000	0.07	401.32	45.81	0.34	136.20
2001	0.07	401.32	45.81	0.24	189.50
2002	0.07	401.32	45.81	0.30	151.69
2003	0.07	401.32	45.81	0.64	71.96
2004	0.07	401.32	45.81	0.39	118.74
2005	0.07	401.32	45.81	0.23	198.10
2006	0.07	401.32	45.81	0.57	80.71
2007	0.07	401.32	45.81	0.35	129.34
2008	0.07	401.32	45.81	0.26	179.59
2009	0.07	401.32	45.81	0.08	563.97
2010	0.07	401.32	45.81	0.06	774.13
2011	Scrapped	Scrapped	Scrapped	Scrapped	Scrapped

[a]

The capacity factor is calculated directly from the data using a generator's nameplate capacity and the amount of electricity delivered by the generator. The generator in this example is interesting because it was scrapped in 2011. Because the generator is being phased out of production, the capacity factor has been declining since at least 1998. The capacity factors are reported in the fifth column. What is important in this example is how the cost of capital, reported in the last column, is affected by the capacity factor. The cost of capital in 1998 was $kr98.55/MWh$, but as capacity was utilized less, costs increased substantially. In 2010, the year prior to being scrapped, the capacity utilization rate was only six percent, resulting in a capital cost equal to $kr774.13/MWh$. It is clear that capacity factors will play a significant role in determining annual changes

[9]The calculations for a wind turbine are identical except that there are no fuel costs.

in the cost of generating electricity. It is vital that capacity factors are accurate. Fortunately, we calculate capacity factors for each generator directly from production data.

The breakdown of fuel costs are provided in table 3.2. This generator burns two types of fuel: coal and heavy fuel oil. The burner tip costs must take into account the contributions to total costs by both fuels. In the first columns of the table are reported the price of coal and heavy fuel oil including freight and insurance. We can calculate these prices directly from the Danish energy accounts.[10] So, importantly the prices used in this study are actual expenditures borne by Danish producers. It is clear from the table that the price of coal is much lower than the price of heavy fuel oil. However, heavy fuel oil has a higher heat content than coal. The price of each fuel, adjusted for their heat contents, are reported in columns six and seven. The differences in the price is not as pronounced because fuel oil has a higher heat content than coal. This is why accounting for the fact that generators use different fuels is important. We calculate the heat content of each fuel using data from the Danish energy accounts. This is why the heat content can vary over the years.

The thermal efficiency of a generator is calculated directly from the production data for each generator. The thermal efficiency for our example generator is reported in column eight. It is impossible to calculate the thermal efficiency of a generator when it uses a specific fuel. Only the overall efficiency can be calculated since we observe aggregate deliveries and not production conditional on the type of fuel used. We assume that thermal efficiency for the generator is the same for each type of fuel it uses.

It is important that the actual use of each fuel is accounted for because the cost difference between coal and heavy oil are substantial. To calculate the burner tip cost of a generator we calculate the weighted sum of the cost of each fuel where the weights are each fuel's share of aggregate fuel input. The input share for coal is reported in column for this example generator. The generator initially used mostly coal, but the generator began to be phased out of production, more fuel oil was used and less coal. The burner tip costs are reported in the last column. Importantly, the burner tip costs reflect the quantity of each fuel that the generator actually used.

The aggregate costs are reported in table 3.3.[11] The total costs for this generator are reported in the second column. The total cost is the per megawatt hour cost of the electricity produced by this generator between 1998 and 2011. This is the costs of only one generator in a system that includes many generators. We are ultimately interested in computing the average per mega watt hour cost of generating electricity in Denmark. Therefore, we need to compute the contribution that individual generators make to overall costs. We use production data to compute each generator's share of aggregate electricity produced by Danish generators. We then use these shares to calculate each generator's share of overall costs; essentially, we calculate a production weighted average of each generator's cost of generating a MWh of generating electricity. The contributions to aggregate costs are reported in the third column.

We also report the results of various alternative scenarios in the remaining column in table 3.3. The alternative scenarios involve changing the various components of capital costs because they involve the most uncertainty. Each of the scenarios illustrate the effect on the generators contribution to aggregate costs. In scenario 1, we increased the interest rate from six percent to 10 percent. In the second scenario we increased capacity factors 70 percent in each year. In scenario 3, we increased overnight costs by 2 million kr/MW, and in the final scenario, we increased the lifetime of the generator to 45 years.

[10] An extensive discussion of data sources are provided in chapter 5.

[11] Note that we do not include environmental costs or operation and maintenance costs in this example since these are simple calculations and we wanted to emphasize the calculations involved with computing capital costs and fuel costs. Environmental costs as well as operation and maintenance costs are discussed in Levitt and Sørensen (2014).

Table 3.2: Cost of Fuel

Year	Price of Coal $(kr/Ton.)$	Price of Fuel Oil $(kr/Ton.)$	Coal Density $(MWh/Ton.)$	Fuel Oil Density $(MWh/Ton.)$	Coal Adj. Prices (kr/MWh)	Fuel Oil Adj. Prices (kr/MWh)	Thermal Efficiency (%)	Coal Share (%)	Burner Tip Cost (kr/MWh)
1998	256.46	460.39	6.99	11.29	36.68	40.77	37.87	80	99.01
1999	211.37	1459.22	7.00	11.29	30.21	129.23	34.87	70	171.85
2000	257.74	1243.84	6.95	11.29	37.09	110.16	35.06	70	168.31
2001	341.04	1024.14	6.97	11.29	48.90	90.70	34.65	70	177.34
2002	258.16	1125.30	7.03	11.29	36.73	99.66	36.40	50	187.35
2003	255.30	1054.11	7.02	11.29	36.39	93.35	36.23	50	179.08
2004	349.01	1049.43	6.89	11.29	50.67	92.94	35.62	50	201.57
2005	378.10	1604.04	6.85	11.29	55.22	142.06	34.74	30	333.94
2006	386.72	1873.48	6.93	11.29	55.84	165.92	36.65	30	362.55
2007	419.72	2563.22	6.83	11.29	61.45	227.00	35.96	30	493.15
2008	632.17	3838.27	6.81	11.29	92.80	339.92	35.35	10	891.67
2009	479.76	2715.18	6.85	11.29	70.05	240.46	30.16	10	740.68
2010	564.22	3048.86	6.79	11.29	83.11	270.01	28.27	10	889.08
2011	696.59	3958.87	6.77	11.29	102.86	350.60	Scrapped	Scrapped	Scrapped

[a] notes Authors own calculations.

Table 3.3: Total Costs (kr/MWh)

Year	Total Costs	Cont. Agg. Costs	Scenario 1 Int. Rate	Scenario 2 Cap. Factor	Scenario 3 Overnight Cost	Scenario 4 Lifetime
1998	197.57	19.76	24.38	16.45	23.28	18.78
1999	667.64	66.76	90.04	23.73	84.50	61.87
2000	304.51	30.45	36.85	23.38	35.32	29.11
2001	366.84	36.68	45.58	24.28	43.46	34.81
2002	339.04	33.90	41.03	25.28	39.33	32.41
2003	251.03	12.55	14.24	12.23	13.84	12.20
2004	320.32	16.02	18.80	13.35	18.14	15.43
2005	532.04	26.60	31.25	19.97	30.15	25.62
2006	443.26	22.16	24.06	21.40	23.61	21.76
2007	622.48	31.12	34.16	27.93	33.44	30.49
2008	1071.26	10.71	11.56	9.57	11.36	10.54
2009	1304.66	13.05	15.69	8.06	15.06	12.49
2010	1663.21	16.63	20.27	9.55	19.40	15.87
2011	Scrapped	0	0	0	0	0

[a]

Chapter 4

Thermal Electricity Generation Technologies in Denmark

4.1 Introduction

In this chapter, we take a close look at the various thermal technologies generating technology in the Danish power system. That is, we provide a breakdown of the different types of generators that operate within the Danish power system and study the various attributes of these generators. The goal is to provide a clear picture of the mix of technology generating electricity in Denmark.

Cataloging the different types of generators and then analyzing the current state of the diverse set of technologies is critical for both computing the aggregate costs of producing electricity as well as explaining the evolution of these costs over time. The cost of generating electricity from a specific generator are clearly dependent on the technology and attributes of the generator. Moreover, aggregate costs depend on the mix of the different types of generators each with their specific attributes. Generators can differ in their balance between fixed and variable costs as well as in front or production loaded costs. For example, it is obvious that wind generators are different from thermal generators: Each of these technologies have different production and cost profiles. Both wind generators and thermal generators have initial fixed set-up costs, which are of course different, but thermal generators have larger marginal production costs relative to wind generators. Even within a specific class of technology, individual generators can have different attributes which can affect costs. For example, there exists different types of wind turbines each having different production characteristics and different cost profiles. For example, the location of a wind turbine, its capacity as well as vintage, are all important determinants of the costs of producing electricity from wind.

There exists a variety of different types of thermal generators producing electricity in Denmark. Differences between thermal generators exist in a number of different dimensions. For example, generators vary according to whether they produce only electricity or can produce both heat and electricity, generators use a variety of different fuels as well as have different efficiencies and capacities. All of these characteristics influence the costs of generating electricity from a specific generator.

It is clear that a generator's technology is a critical factor in determining the costs of producing electricity by that specific generator. In addition, the overall mix of generation technology is an important determinate of aggregate production costs. There are some thermal generators that have very large production costs, but have little affect on aggregate costs because they only supply a small fraction of aggregate electricity. Moreover, changes in production costs over time will be partly due to the changes in the mix of generators. For example, wind generation has grown to be an integral part of the Danish power system. Indeed, wind generation has displaced some thermal generation which then influences aggregate production costs. Moreover, the cycle of decommissioning older generators and installing newer generators will also affect aggregate costs.

There are two important reasons to study generation technology at the level of the generator. First, computing the aggregate cost of producing electricity requires calculating costs at the level of the generator because the set of generators is so heterogenous. Second, determining how the mix of technology influences aggregate costs requires that we construct a mapping between the costs of specific generators to aggregate production. Denmark provides an interesting opportunity to study the costs of producing electricity because of its relatively unique power sector. In particular, there are two reasons why studying Denmark's power sector is interesting: first, a large variety of technology is used to produce electricity and, second; the mix of generation technology continues to change relatively quickly. Understanding the costs of producing electricity in an environment characterized by a diverse set of technologies that is also evolving relatively quickly can inform policy.

The remaining parts of this section are organized in the following way. In section 4.2, we first describe aggregate generation and classify generators into thermal and nonthermal generators and describe their production trends. In section 4.3, we provide a fairly detailed description of thermal generation in Denmark. The objective is to highlight the different characteristics of the thermal generators in Denmark that have important effects on the costs of generating a megawatt of electricity.

4.2 Overview of Thermal Generation in Denmark

There are two broad categories of electricity generators based on how power is generated: The two categories are thermal and nonthermal. Thermal generators are the largest source of electricity in Denmark. Although nonthermal generation, specifically from wind, is making a substantial contribution to aggregate electricity output and is expected to expand in the foreseeable future. Thermal generators convert heat energy produced from combustion into mechanical energy. The mechanical energy generated from the heat energy operates an electrical generator which produces the electricity. Thermal generators require a renewable or nonrenewable source of fuel to burn since electricity is generated via combustion. Coal and natural gas continue to be the main fuel for thermal generators. However, nontraditional sources, like biomass, straw and municipal waste, are increasingly being used as fuel.

Nonthermal generators use kinetic energy to drive turbines to create power. The most important and perhaps recognizable source of kinetic energy in Denmark is from wind. In addition, there is a small amount of electricity generated from hydro power. In 2012 electricity from hydro power accounted for less than one percent of aggregate production (see figure 4.2). Finally, there is also a very small, but growing, solar sector in Denmark. The amount of electricity generated from solar power is still insignificant. However, the amount of solar power has been increasing recently whereas hydro power has been decreasing (see Levitt and Sørensen (2014)).

In this chapter, we focus on thermal generators. Electricity produced from thermal generation is organized across three types of producers: central plants, industrial producers (also called autoproducers) and public power stations. The bulk of the large thermal generators are installed in central plants which often consist of multiple generators. Most of these large central plants produce both electricity and heat in a combined process called cogeneration (or combined heat and power). These large plants typically serve base-load electricity demand and district heating demand.[1] Public power stations are smaller than central power stations. Even the smaller

[1]Base-load power plants are designed to meet some or all of a given region's continuous energy demand. These plants typically produce electricity at a constant rate relative to peak-load generators. Peak-load generators are designed to provide power during

Table 4.1: Electricity Generation in Denmark (GWh), 2000–2011

Production Year	Net Production	Central Power Stations	Public Power Stations	Industrial Producers	Wind Turbines	Hydro Power
2000	34,257	21,172	5,553	3,260	4,241	30
2001	36,009	22,235	6,251	3,189	4,306	28
2002	37,258	22,995	6,254	3,100	4,877	32
2003	43,757	28,811	6,189	3,176	5,561	21
2004	38,378	22,398	6,260	3,110	6,583	27
2005	34,349	18,855	5,513	3,344	6,614	23
2006	43,349	28,815	5,437	2,966	6,108	23
2007	37,396	22,730	4,848	2,619	7,171	28
2008	34,736	20,549	4,943	2,291	6,928	26
2009	34,451	20,963	4,616	2,133	6,721	19
2010	36,763	21,075	5,664	2,193	7,809	21
2011	33,382	16,931	4,642	2,018	9,774	17

[a] Statistics obtained from the Danish Energy Agency's Monthly Electricity Supply Report 2011.

scale public power stations can generate both electricity and district heat. Autoproducers typically generate either electricity or heat, and sometime both, typically for use in their own industrial processes. The electricity generated by autoproducers is typically not generated for distribution, but rather for use by the producer.

An overview of electricity generated by thermal and nonthermal generators in Denmark from 2000 to 2011 is provided in table 4.1. The table reports the amount of electricity generated by central plants, industrial producers, public power stations as well as by wind and hydro generators. In addition, we report electricity production shares in figure 4.1. Note that Central plants, industrial producers and public power stations generally use thermal generators. The average amount of electricity produced over the 12 years was just under 39 thousand GWh.[2] There was no significant trend in the amount of electricity produced over the 12 years. However, there was annual variation in generation. In 2006, over 43 thousand GWh of electricity was generated in Denmark, whereas in 2011, about 33 thousand GWh was generated. The standard deviation in annual production is 3.6 thousand GWh. There are a number of reasons for the observed annual fluctuation in production. In general, the amount of generation depends on market conditions determined by the demand for electricity within Denmark and abroad as well as the amount of electricity generated (or potentially could be generated) in countries connected to the Danish power system. There are many factors which influence the supply and demand of electricity.

The majority of electricity produced in Denmark is generated by the large-scale central plants which typically consist of multiple thermal generators. Central power stations generated, on average, just under 22 thousand GWh of electricity between 2000 and 2012. On average, these large-scale plants generated 59 percent of the total electricity produced. Since 2007, the amount of electricity generated by these large-scale plants seemed to have been declining. Indeed, from figure 4.1, it is clear that their share of aggregate production had been declining since 2006.[3] Comparing winds' share of production to the central power station's share suggests that over the last decade, an increasing fraction of electricity generated by the large central stations was being replaced by wind generation, so that by 2011, the share supplied by central plants decreased to about 50 percent of total

periods of high-demand. Peak-load generators can typically be started in a relative short period of type and are typically more costly to operate than base-load generators.

[2] This is production not consumption. Consumption of electricity in Denmark will not equal production because of exports and imports. The international trade of electricity is discussed in chapter 6. Some of the electricity produced in Denmark is exported.

[3] The exception occurred in 2009 when there was a slight increase in production. However, the amount of electricity generated and its share of total output was less than was produced in 2006.

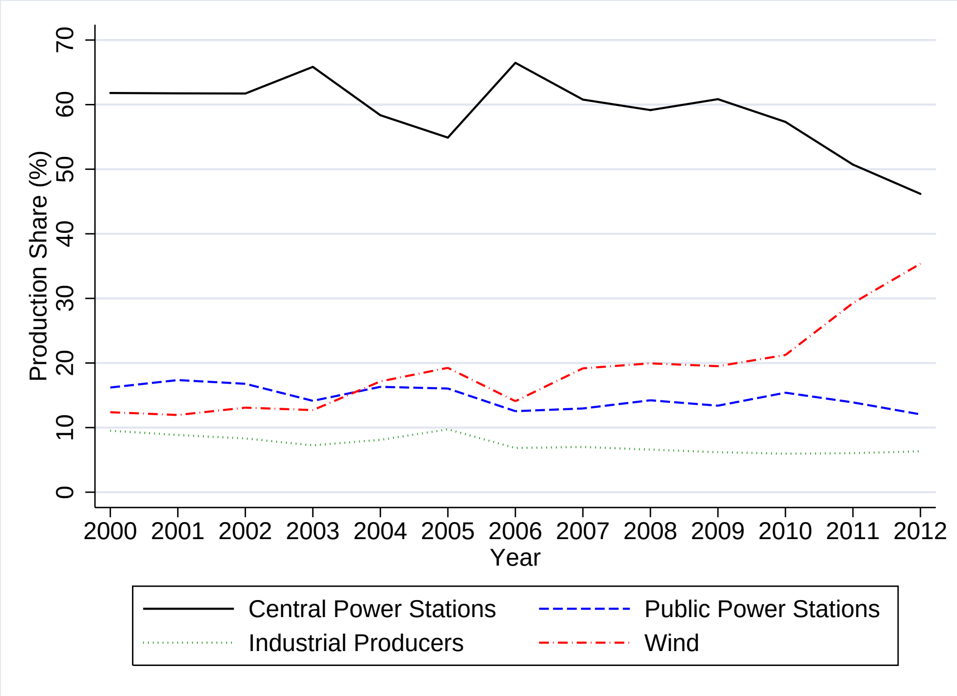


Figure 4.1: Production Share, 2000-2011

supply. Wind generation continues to grow as an important source of electricity in Denmark. In 2000, wind accounted for just over 12 percent of electricity production in Denmark, and by 2011, 28 percent of electricity was being generated by wind.

Industrial producers and public power stations play a nontrivial role in producing electricity. Industrial producers' share of production ranged between 10 percent and six percent, whereas public power stations accounted for between 17 percent and 13 percent of production. Industrial producers are small producers whose main role is not to supply electricity to the grid but rather produce electricity for their own consumption. The share of electricity produced by public power stations has been relatively stable since 2000. Industrial producers have tended to produce less electricity since 2000.

In figure 4.2, we illustrate the mix of generation in 2012. The trends observed in table 4.1 as well as in figure 4.1 are evident in the 2012 production data. Wind generation continues to grow and replace thermal generation by central plants. There is not much of a change in the amount produced by industrial producers or public stations. The amount of electricity generated by hydro power is essentially negligible.

Large-scale central producers as well as the small-scale public producers and autoproducers all use a mix of different technologies to generate electricity. For example, combined-heat-and-power (CHP) plants will have a different cost and revenue structure than a small-scale autoproducer generating electricity using a gas engine. Moreover, even within the same class of technology, condensing generators for example, generators can have different attributes that will influence costs. Generators will differ, for example, in their capacities and vintages, which will affect cost structures. Because the cost structures across different technologies, and within the same class of technology, can be quite different, it is important that we are able to construct costs at the generator level. Aggregate production costs will then depend on the overall mix the generators. In the next section we provide comprehensive description of thermal generation in Denmark which will help in the analysis of the costs calculated in Levitt and Sørensen (2014) and chapter 6.

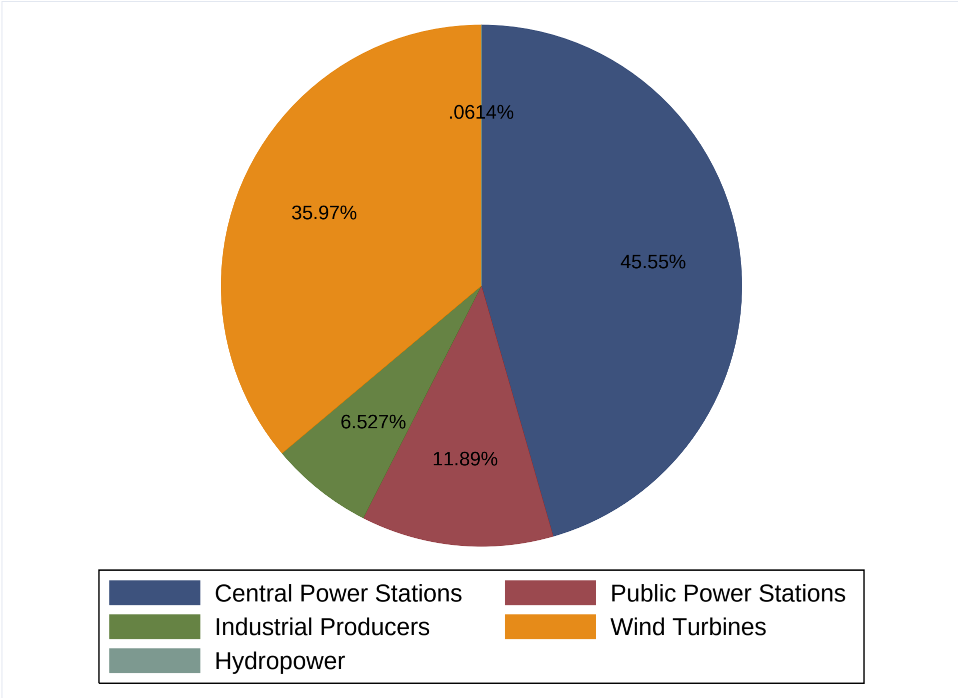


Figure 4.2: Production Share, January-November 2012

4.3 Thermal Generators

Calculating costs at the level of the generator requires that we have access to attribute and production data for each generator. Fortunately, comprehensive data on thermal generators operating in Denmark have been provided for this study by the Danish Energy Agency. The data cover 1998 to 2011.[4] These data consists of 796 power plants that operated between 1998 and 2011. Plants often operated more than one generator. The data contain information about the production and the technological attributes for 1145 unique generators.

We begin our analysis of thermal generators in the next section by first looking at capacities and electricity production. Next, we turn to studying fuels in section 4.3.2. In section 4.3.3, we provide an overview of different types of generators that produced electricity between 1998 and 2011. In section 4.3.4, we look at the age profiles of important classes of generators.

4.3.1 Capacity and Production

An important characteristics of Denmark's power system is the intensive use of co-generation. Indeed, Denmark's power system has one the world's most intensive use of co-generation. Co-generation or combined-heat-and-power (CHP) is the simultaneous generation of electricity and useful heat. A by-product of thermal electricity generation is heat, which if not used, is released into the atmosphere as waste heat (after being treated). The energy content that exists in the waste heat is discarded. However, CHP units in Denmark capture some of this heat which is then typically used for district heating.

There are two benefits of CHP. First, by capturing the excess heat, CHP uses heat that would be wasted in a conventional power plant, thereby increasing the thermal efficiency of the plant. Economically, this means that less fuel needs to be consumed to produce the same amount of useful energy. Second, the waste heat is

[4] The data have been provided to the researchers under the condition that they remain confidential. We are not permitted to make public data concerning individual generators or firms. We are not permitted to release subsets of the data from which it is possible to identify individual generators or firms.

essentially transformed into a commercial product representing another source of revenue for the power plant operators.

The intensive use of CHP is illustrated in tables 4.2 and 4.3. In the first table, we provide an overview of capacities of CHP and conventional thermal generators, whereas in the second table, we provide statistics on generation. It is evident from table 4.2 just how intensive CHP is used in Denmark. The majority of generators produce both electricity and heat. Over 95 percent of generators operating between 1998 and 2011 were CHP generators. Although, the number of conventional generators has increased from 18 in 1998 to 52 in 2011, conventional generators still only accounted for approximately 5.5 percent of total generators. The importance of CHP generation is also demonstrated by comparing capacities. The average capacity of conventional generators is greater than CHP generators. However, in terms of the aggregate installed generation capacity, more than 93 percent of electricity capacity is CHP.

There are some interesting trends in these data that could have important implications for the evolution of production costs over the 14 year period. The electricity generation capacity of the average electricity producing plant has been declining over time. At the same time, the number of actual generators has been increasing. The declining trend in electricity capacity is due to the installation of smaller generators and decommissioning of older larger generators (see section 4.3.4 for more detail). The average electricity capacity of CHP plants has not changed substantially since 1998: less than a 3 MW average reduction since 1998.

Looking at production statistics reported in table 4.3 reinforces the significance of CHP in Denmark. In the table, we report electricity and heat production by CHP generation and electricity production by conventional generation. The bulk of electricity produced by thermal generators has been by CHP generators. Average annual electricity production by CHP generators was approximately $31,910GWh$, whereas average production by conventional generators was $1,730GWh$. So, over the sample period, more than 97 percent of electricity produced by thermal generators was produced by CHP plants. The average production of individual generators was approximately $30GWh$ for standard generation and $40GWh$ for a CHP generator.

We again examine trends in generation in figure 4.3 in which we plot annual electricity production by conventional and CHP generators. The striking feature of the data is the rapid decline of conventional generation since at least 1998. In 1998, conventional generators produced approximately $2,500GWh$ of electricity, but by 2004, they were generating less than $100GWh$ of electricity. Consequently, the share of thermal electricity production by conventional generation has declined from about 7 percent in 1998 to less than a quarter percent in 2011 (see table 4.4). Conventional generation capacity has also decreased in 1998, but the trend has not been as severe as production. This seems to indicate that there is a large amount of conventional capacity that is not being used.[5] The second interesting feature of the data presented in figure 4.3 is the spikes in production observed in 2003 and 2006. Note that these spikes are also seen in figure 4.1.

The prevalence of CHP in the Danish power system poses some difficulty for calculating costs for two reasons. First, because the CHP plants produce both electricity and heat, it would be wrong to assign all the costs of the generator to producing electricity. It is important that the energy used to produce heat is accounted for in the analysis. Second, because these generators can be of two types: first, heat produced by generating

[5] Indeed, in chapter 2 of Levitt and Sørensen (2014), we calculate capacity rates for conventional generators, backpressure generators is one example, and show that these generators have very low capacity rates resulting in large per unit production costs.

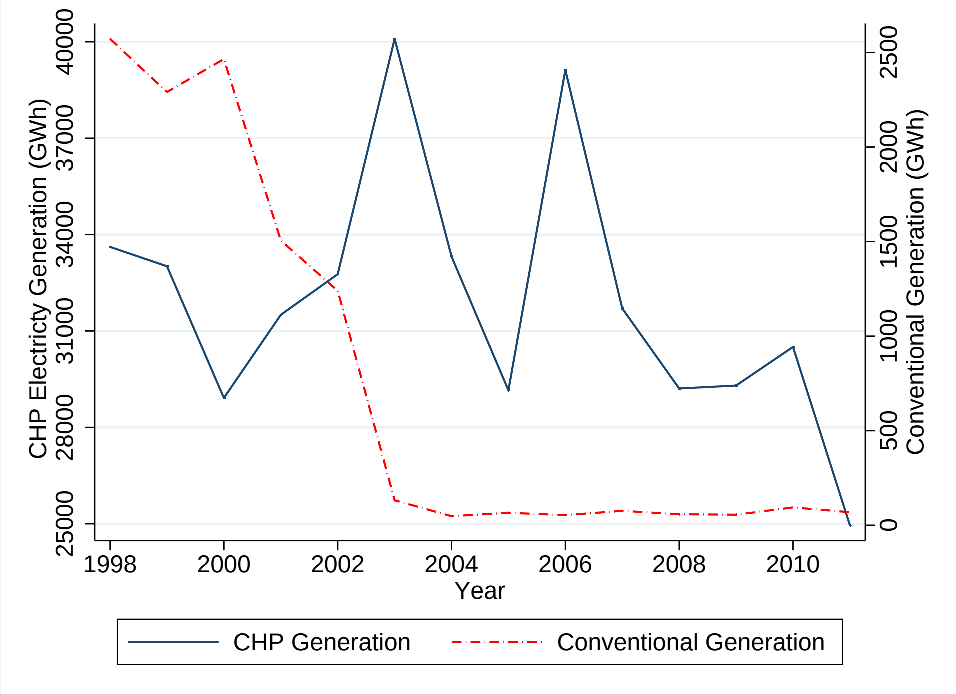


Figure 4.3: Annual Production, 2000-2011

electricity could be an exogenous by-product of thermal generation; second, the production mix of heat and electricity could be endogenous. In the second case, producers decide on how much heat and electricity to produce. These are important differences because if the heat generated from generating electricity is strictly a positive externality then it should be considered as a benefit in any cost-benefit analysis. If producers must make a tradeoff between generating electricity and producing heat then generating heat is not without costs. The opportunity cost of producing heat is the value of any electricity that could have been produced. We discuss these technologies in more detail further in the study.

4.3.2 Fuels

Thermal generators require a fuel (or multiple fuels) to burn in order to generate electricity. We show in chapter 5 as well as in Levitt and Sørensen (2014) that the burner-tip costs of fuel are a significant component of the costs of generating electricity.[6] Because fuels are a necessary and costly input to thermal generation we next introduce the various fuel inputs burned by thermal generators to produce electricity. We take a close look at the two traditional fuels that have historically supplied most of the demand for fuel: coal and natural gas. We also take a peek towards the future and suggest which fuels are likely to grow and which fuels are likely to shrink.

Between 1998 and 2011 thermal generators used approximately 16 different types of fuel. Of course, not all fuels were used to the same degree. The power system consists of different types of generators that perform different functions within the system. A prime example are the large coal-fired central plants that serve base-load demand and the small-scale generators that serve peak-load demand or serve as a backup to intermittent generators (wind turbines for example). These generators will likely differ in the kinds of fuels they burn as well as in the amount of fuel they use. In addition, fuels have different functions in generation. For example,

[6] Burner tip prices are defined, for the purpose of this study, as the amount paid for a fuel that is burned at a generator. The burner tip price include not only the cost of the fuel itself (commodity price), but transportation costs as well. Fuel costs also depend in the thermal efficiency of the generator; less efficient generators require more fuel to generate an equivalent amount of electricity that was generated by a relatively more efficient generator.

coal and natural gas are the main fuels burned during continuous electricity generation, whereas gas oil and refinery gas, for example, are often used in the startup process of large generators.

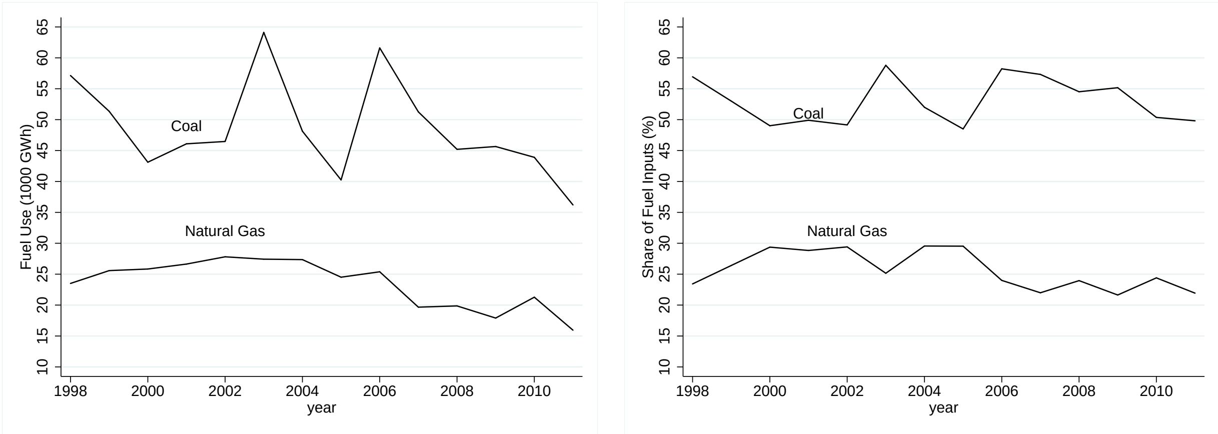
An overview of the different fuels that have been used by the thermal generators in Denmark is provided in table 4.5. The traditional fossil fuels, coal and natural gas, account for more than 75 percent of aggregate fuel usage. Coal is the primary fuel accounting for over 51 percent, whereas natural gas accounted for just under 25 percent. Waste, which is primarily used in CHP waste plants, which are an important segment of the Danish district heating system, is the third largest input accounting for around 7 percent. The remaining fuels account for a much smaller share of fuel consumption.

Looking at the number of generators that use the different fuels provides a sense of the size of the generators burning the different fuels which provides an indication of how some of the fuels are used. Around three percent of the generators use coal, but generated, on average, almost 50 thousand GWh of electricity annually. In contrast, approximately 65 percent of generators (over 560 units) burned natural gas, but produced less than half the amount of coal burning generators.[7] This difference is due to the functions of the generators. Generators burning coal are generally located in large central plants which generate electricity to meet base-load demand and produce heat for district heating. Natural gas generators are typically smaller and can be used in different ways compared to the large-scale coal plants. Gas turbines, for example, are used in public power stations to serve peak-load demand because they can typically be started quicker and cheaper relative to large-scale coal plants. Autoproducers also use natural gas turbines to generate electricity or heat for their own consumption.

The burner tip costs of coal and natural gas will have important implications for aggregate generation costs because they account for around 75 percent of aggregate fuel consumption. Moreover, any annual fluctuations and long run trends in the consumption patterns of these fuels will also affect aggregate costs. Coal and natural gas consumption is reported in figure 4.4. The figure reports both consumption levels as well as shares of total fuel. The data suggests that coal consumption has been declining since at least 1998. However, there were large jumps in consumption in 2003 and again in 2006. These spikes coincide with the data presented in figures 4.1 and 4.3 which show that coal is largely used in the large-scale central CHP plants which serve base-load demand. Therefore, when the base-load demand for electricity increases there will be a corresponding increase in the demand for coal. Interestingly, there is not a noticeable long run trend in coal's share of aggregate fuel consumption. There are substantial annual variations in the share for some years. Only since 2006 has there been a slight declining trend–the same trend that is illustrated in figure 4.3 –highlighting again the fact that coal is used primarily in the large central CHP plants.

The consumption of natural gas also declined over the same period. Although, natural gas consumption did not start to decrease until after 2004. Also similar to coal is the modest decline in the share of natural gas since 2005. The overall picture seems to be that the mix of natural gas and coal as a source of fuel has not changed significantly over time. However, the consumption levels have changed over time. The declining use of natural gas and coal, particularly post 2003, is partly due to the increase in the amount of electricity generated from wind turbines. Any impact on costs from these long run trends will be through changes in the consumptions levels of coal and natural gas. Any long run changes due to changes in the mix of fuels will be modest at best. However, annual fluctuations in costs could be affected by the variance of the mix of coal and natural gas. Of course, the effects on costs due to changes in consumption patterns will also be dependent on any changes in the burner tip costs.

[7] Some generators used both coal and natural gas. Indeed, generators often used a few different fuels. Fuel usage for each type of generator is analyzed extensively in Levitt and Sørensen (2014).



(a) Coal and Natural Gas Consumption

(b) Coal and Natural Gas Share

Figure 4.4: Coal and Natural Gas, 1998–2011

Some fuels that were used previously are not longer used. For example, orimulsion, up until 2004, was an important fuel accounting for almost seven percent of total fuel consumed by thermal generators.[8] However, the fuel is no longer used by Danish thermal generators. There are some fuels, in contrast to coal and natural gas, and indeed, orimulsion, in which their share of aggregate fuel usage has been increasing: waste, straw and wood products (pellets and chips) have all experienced growth in their consumption shares. Figure 4.5 illustrates the consumption share pattern for these fuels. The use of waste has consistently been growing since at least 1998. Wood products has been growing since 2002; although there was a one year decline observed in 2005. Nevertheless, by 2011, wood products accounted for almost 13 percent of aggregate fuel consumed by thermal generators. In general, biomass, is considered to be an important replacement for coal in the long-run. Indeed, the long-term objective of Danish energy policy is to convert large-scale CHP production away from coal and towards biomass (see Danish Minsitry of Climate, Energy and Building (2012) for additional details concerning energy policy initiatives of the 2012 Energy Agreement). Comparing figures 4.4 and 4.5, one can see that, since at least 2006 (2005 when looking only at natural gas), biomass has started to supplant some coal and natural gas.

4.3.3 Specific Technologies

As mentioned previously, the Danish power system consists of different types of thermal generators, each performing a specific role in the system. Generators differ along many different characteristics, including output (electricity or heat and electricity), capacities, ramp rates (how quickly a generator can increase or decrease generation), turn-down capability (large generators typically have high minimum generation levels relative to smaller generators that have high ramp rates), among many others. Although we study each class of generators in detail in Levitt and Sørensen (2014), it is worthwhile getting a handle on the different types of generators, and how they differ from each other, before getting into the specific details of each generator. An overview of the technology provides an opportunity to see where each technology fits into the Danish power system. To this end, in table 4.6, we report the different classes of thermal generators that produced electricity at some point between 1998 and 2011.

[8] Orimulsion is a liquid fuel made up of 70 percent bitumen and 30 percent water. The fuel is manufactured in Venezuela from the bitumen deposits of the Orinoco belt.

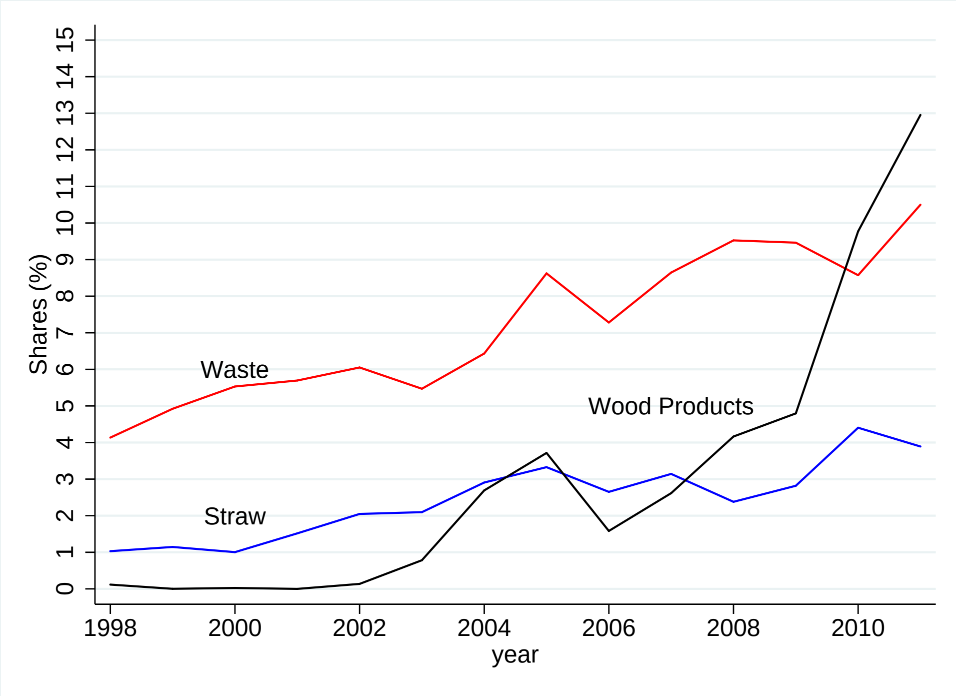


Figure 4.5: Alternative Fuels, 1998-2011

The table lists nine types of generators. Clearly, some classes of generators are more important than others. Steam turbines are the largest class of generators in terms of both capacity and electricity production. They are typically installed in large-scale central plants and supply base-load demand for both electricity and heat. The large steam turbines are typically designed to run constantly having relatively long ramp rates and usually must operate above a minimum generation level (low turn-down capability). Steam turbines generated most of the electricity in the Danish power system because they serve base-load demand. Steam turbines generated annually almost $25,000GWh$ of electricity, on average.

There are two broad types of steam generators: first, non-condensing (open-cycle), or back pressure turbines; and second, condensing (closed-cycle) turbines. In non-condensing turbines, the exhaust steam leaving the turbine is used in either a co-generated process (generating heat, for example) or, more rarely, released into the atmosphere (after being treated in some way). In a closed-cycle turbine, also called condensing generators, the exhaust steam is condensed into water which is then used by the generator as feedwater. Some open-cycle turbines, namely extraction turbines, can be configured to have the ability to switch between condensing and back-pressure modes. Moreover, extraction turbines have the capability to vary the amount of electricity and heat generated. Back-pressure generators produce heat at essentially a constant rate given the amount of electricity that is generated. Condensing turbines do not have the capacity to contribute to a cogeneration process. Waste-to-energy steam turbines is another important technology that is likely to continue to grow in both capacity and generation. Waste-to-energy turbines use municipal waste to generate electricity and heat. Indeed, these generators are a significant part of district heating systems generating over a thousand GWh of electricity and 14 thousand tj of heat (see table 4.7).

Gas turbines are the second largest class of generators operating in the Danish power system. These generators typically have high ramp rates (typically can be started or stopped within minutes) and do not have a restrictive turn-down capability. These characteristics make these generators suited to serve peak-load demand or provide power (or heat) for specific industrial uses (autoproducers).[9] Gas turbines are also well suited to

[9] Generators or even plants that serve peak-load demand are often called peakers.

provide back-up capacity because of their quick on and off capabilities. On average, gas turbines annually generated about $5,000GWh$ of electricity and $24,000tj$ of heat.

Gas turbines consist of two distinct types of generators: single-cycle and combined cycle generators. Single-cycle gas turbines use high temperature, high pressure gas as fuel, to generate heat. Part of the heat generated by the gas is converted into rotational energy which is then converted into power. These generators can also optionally produce usable heat in a cogeneration process. For CHP production a heat recovery boiler is required to process the heat that was not used to produce electricity. Therefore, CHP generators tend to be more costly relative to non-CHP generators. The benefit, of course, is that the waste heat is transformed into usable heat. These single-cycle turbines have the ability to be started and stopped within minutes. Consequently, single-cycle gas turbines are generally used as peaking power plants supplying power during peak demand. The typical capacity of single-cycle generators ranges from 5 MW to 125 MW.

For capacities greater than $15MW$, combined-cycle generation is typically more cost efficient. Combined-cycle generators use two heat engines in a sequence to drive the power-producing generators. The heat discharged from one heat engine serves as the energy source for the second engine. In general, a combined-cycle generator that only produces electricity generally uses a gas turbine as the first heat engine and a conventional condensing steam turbine in the second stage. If the generator is operating in a CHP plant, and is producing both electricity and heat, then the generator is one of two technologies: a back-pressure steam turbine or an extraction steam turbine. In back-pressure generation all the exhaust steam is utilized for heating. Importantly, back-pressure turbines operate under a constant electricity to heat ratio. In extraction steam turbine generation, CHP plants offer the possibility to regulate the amount of heat based on demand. Since the amount of steam to extract is regulated, the producer can respond to changes in demand and optimize revenue. Any steam that is not extracted is condensed and used to produce electricity. Extraction steam turbines are typically large-scale generators with capacities ranging from 100 to $500MW$. Extraction generators are simply too costly to implement in small plants. Small plants ranging from 10 to $100MW$ typically utilize back pressure technology. These larger scaled plants have the potential to serve-base load demand as well as peak-load demand. They are ideally suited to serve as back-up or reserve capacity. Reserve capacity will continue to be in demand as the penetration rates of intermittent wind power increases.

The remaining generators typically serve specific industrial demand and are installed in autoproducer plants. Gas engines are the largest class within this group producing, on average, about $3,400GWh$ of electricity annually. These are small generators having a capacity less than $4MW$. Typically, these generators burn gas oil (diesel) or natural gas.

4.3.4 Age of Thermal Generators

So far in this chapter, we have provided a general overview of thermal generation in the Danish power system. We looked at production and capacity at the level of the plant as well as at the generator level; we described the various fuels that generators use to generate electricity; and we provided an introduction to the different types of generators and their roles in the Danish power system. In this final section of the chapter, we look at the age structure of the generators. The vintage of the generators will have important implications for generation costs for a number of different reasons: first, older technology will generally be less efficient than newer technology; second, older generators generally require more maintenance and tend to have more frequent unscheduled repairs; third, less mature technologies can sometimes include a cost premium due to first-of-a-kind (FOAK) cost structures. Less mature technologies often have larger construction costs compared to more

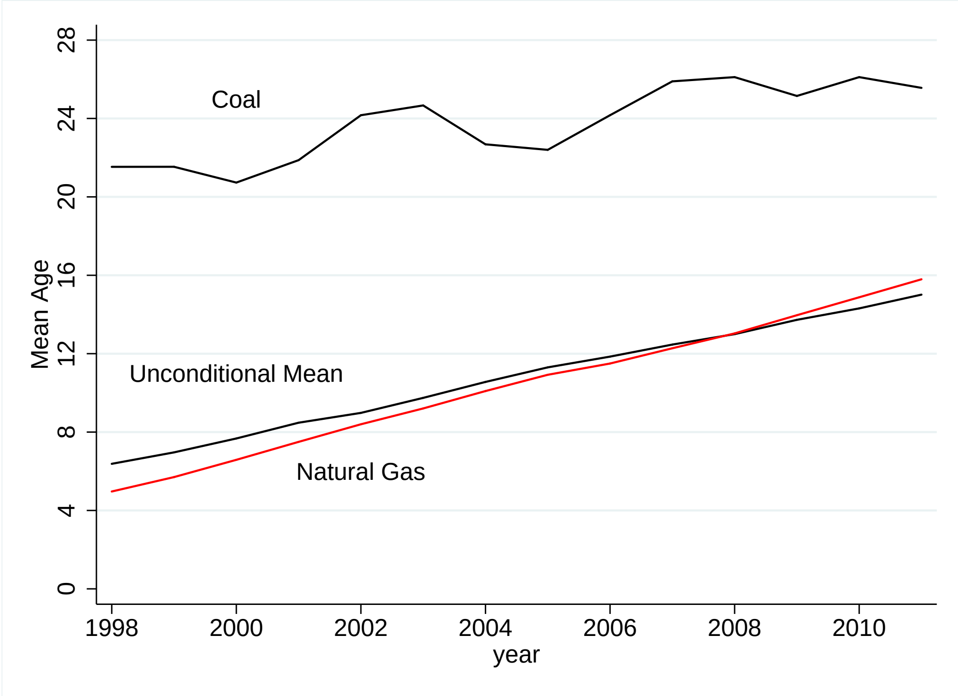


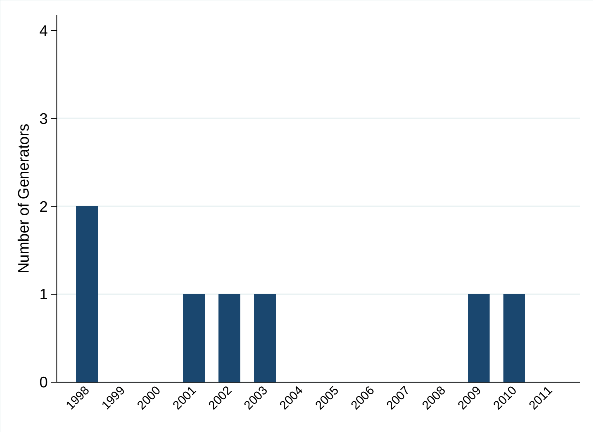
Figure 4.6: Average Age of Generators

mature technologies because they often require new construction techniques and the development of a new supply chain. Learning curves often exist in large engineering projects.

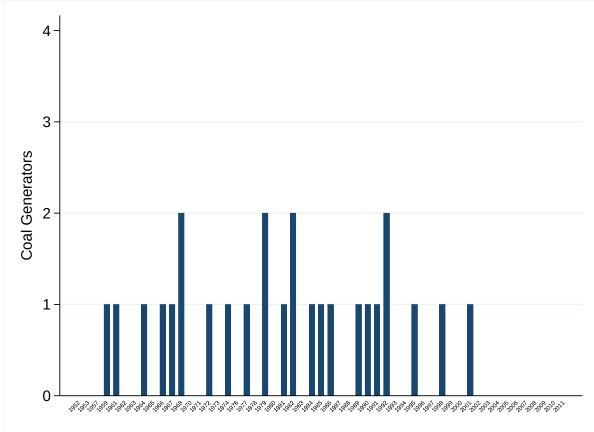
The average age of a generator producing electricity between 1998 and 2011 was 11 years; however, there is substantial variation among generators. Age profiles are determined by installation decommissioning dates. Early investments in generation were in coal-based and heavy fuel oil generators. Recall that the two most important fuels used in thermal generation is coal and natural gas. The average age of coal generators was 24 years, whereas the average age of a natural gas generator over the same period was 10 years. Coal plants are the large-scale, CHP central plants, that serve base-load demand. The age profiles of generators are presented in figure 4.6. The figure consists of three series: the average age of coal generators, the average age of natural gas generators, and the average age of all thermal generators (labeled unconditional mean).

As to be expected, the average age of generators is increasing at a relatively constant rate. Natural gas generators tended to be newer relative to the average age of the generators. Coal generators are almost twice as old as the average generator. The age profile for coal generators exhibits more variability and a relatively flat trend, particularly after 2007. The variability exhibited in the age profile is due to decommissioning of older plants. The troughs observed after the peaks in the time series for coal-based plants were primarily caused by generators being scrapped. Average age must decrease when generators that are older than the average age are scrapped (the older the generator, the larger the decrease in average age) or new generators are installed. We illustrate the dynamics of the age profile of coal generators in figure 4.7. No investments in new coal-based generators has occurred since 2001, but there has been a number of generators decommissioned since 1998. The decrease in the average age of coal-based generators observed immediately post 1998 were the result of scrapping older plants (see panel 4.7(a) in figure 4.7) as well as the installation of a new generator in 1998. The trough observed post 2003 was caused by the scrapping of generators in 2001, 2002 and 2003. The generators scrapped in 2003 was quite old resulting in a large decrease in average age.

As we have demonstrated with coal-based generators, new installations together with the decommissioning of older generators, explain variations the age profiles of within a class of generators as well as across different



(a) Coal Generators, Decommissions



(b) Coal Generators, New Installations

Figure 4.7: New Installations and Decommissions, Coal, 1998–2011

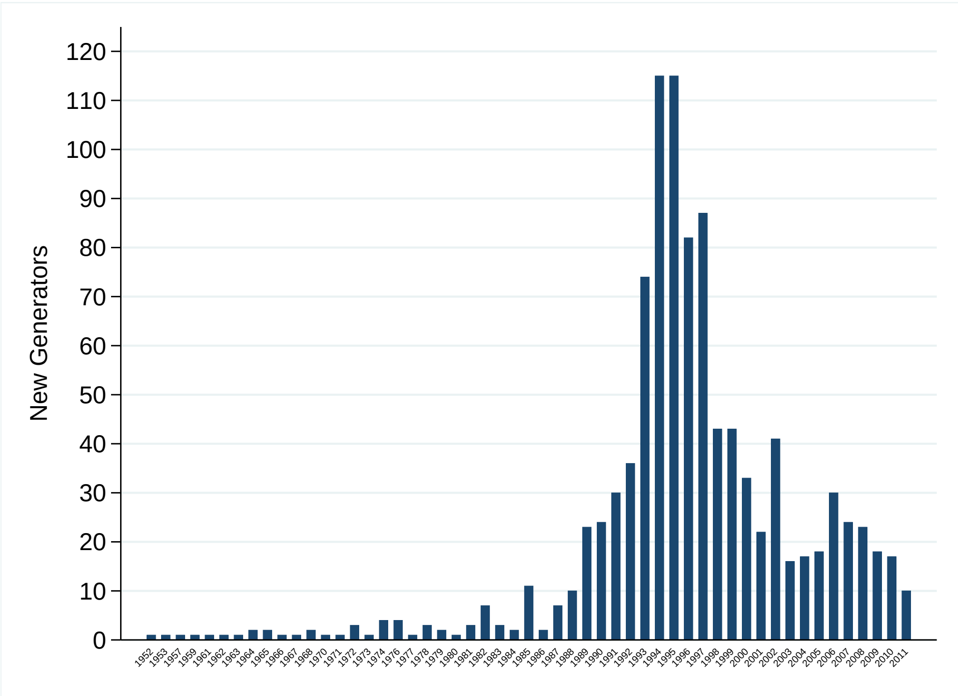
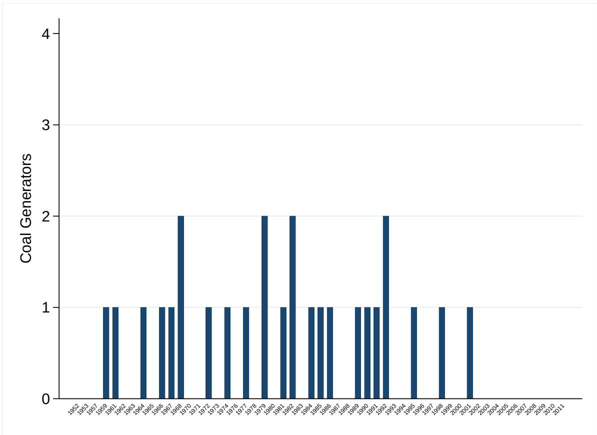


Figure 4.8: Number of New Generators

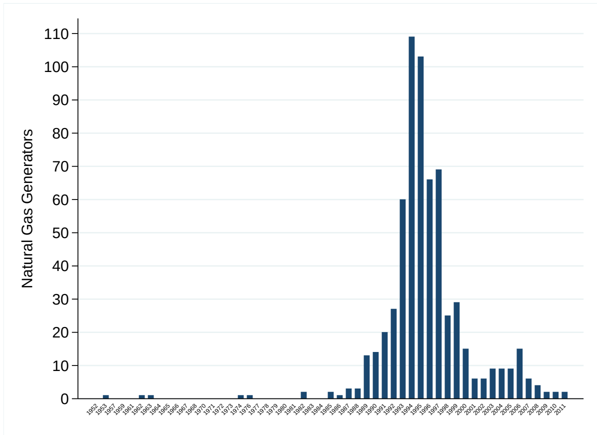
classes of generators. It is easy to see that the mix of vintages are an important determinant of costs. To get an idea of the pattern of aggregate investment in new generation, in figure 4.8, we report the number of new generators installed each year since 1952.[10] The earliest start-up date of a generator was 1933; however, the years preceding 1952 were not that active in terms of new generation and we omitted these dates from the figure. There was a slight increase in the installation rate of new generators between 1964 and 1988. On average, three new generators were introduced each year between 1964 and 1988. There was a substantial increase in the rate of new generators beginning in 1989. The annual number of generator start-ups increased rapidly until 1995: 116 new generators were introduced into the power system in 1995. Post 1995, installation rated declined. However, the number of new generators added each year never dropped below ten units.

What type of technology was being introduced post 1988? In figure 4.9, we report the annual contribution

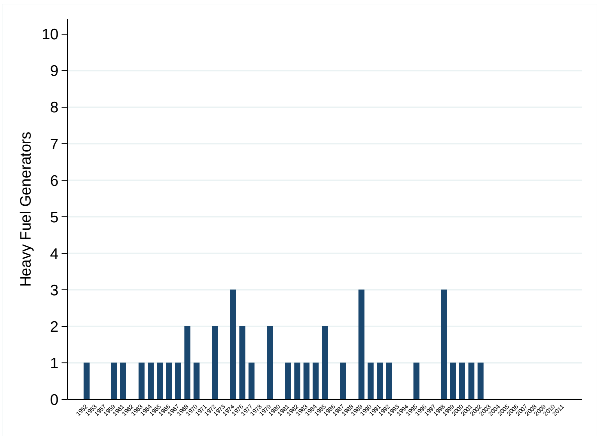
[10]The number of generators was calculating using the initial operating date. This is the date that the generator first produced electricity or heat in the Danish system.



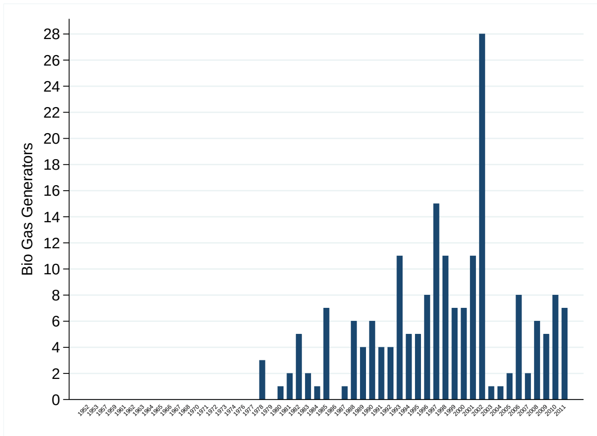
(a) Coal Generators



(b) Natural Gas



(c) Heavy Fuel Generators

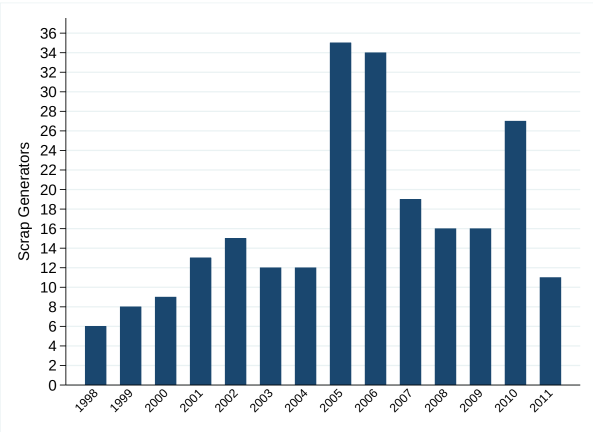


(d) Bio Gas

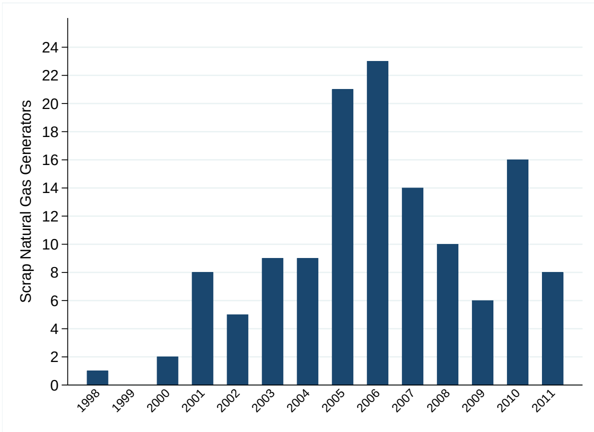
Figure 4.9: Date of New Generator Investments, 1998–2011

to new generation classified by fuel type. The four fuels: coal, heavy fuel oil, natural gas and bio gas, made the largest contributions to the installation profile reported in figure 4.8 (we have included the data for coal again to ease the comparison). The early generators were largely coal-fired generators or heavy fuel oil (in some cases generators burned both coal and heavy fuel oil). The early generators were investment targeting base-load demand. It is clear from panels 4.9(b) and 4.9(d) that the substantial increase in new generators beginning in 1998 was driven primarily by investments in natural gas and biogas generators (some generators burn both natural gas and biogas). The substantial increase in new natural gas generators beginning in 1998 and continuing through to 2000 is also reflected in the consumption of natural gas (see figure 4.4(a)). These relatively new investments targeted peak-load demand as well as investment in backup capacity. A large part of these new investments also consist of autoproducers.

Given the observed pattern of investment in new generators, one would like to know whether these generators represent additional capacity or are generally replacements for older generators. To partly answer this question we report the annual number of decommissioned generators in figure 4.10(a). Comparing panel 4.10(a) in figure 4.10 to figure 4.8, seems to indicate that the majority of new investments have been to replacement scrapped generation units rather than for adding additional capacity. The vast majority of new investments and decommissions have involved natural gas generators.



(a) All Generators



(b) Natural Gas Generators

Figure 4.10: Decommissioned Generators, 1998–2011

Table 4.2: Capacity by Generator Type

	Electricity			Cogeneration			
Year	Number of Generators	Thermal Capacity (MW)	Elect. Generation Capacity (MW)	Number of Generators	Thermal Capacity (MW)	Elect. Generation Capacity (MW)	Heat Generation Capacity (MW)
1998	18	102.83	57.26	755	28.82	11.36	13.08
1999	17	108.88	51.69	762	28.64	11.10	12.92
2000	15	123.40	58.38	776	28.23	10.94	12.74
2001	15	123.4	58.38	782	29.60	11.60	13.45
2002	16	115.69	38.38	814	28.70	11.21	13.02
2003	17	109.21	36.27	818	28.72	10.84	12.80
2004	16	116.03	38.53	818	28.94	10.89	12.93
2005	25	74.49	24.65	850	28.09	10.55	12.50
2006	26	71.68	23.75	846	28.34	10.66	12.55
2007	35	55.58	19.03	839	28.49	10.75	12.43
2008	42	42.29	16.16	848	28.10	10.58	12.09
2009	43	46.20	15.79	851	27.62	10.45	11.46
2010	45	44.16	15.76	852	27.45	10.43	11.45
2011	48	41.59	14.44	838	26.93	10.25	11.09

[a] Authors own calculations.

Table 4.3: Production by Generator Type

	Electricity		Cogeneration			
Year	Annual Elect. Production (GWh)	Mean Elect. Production (GWh)	Annual Elect. Production (GWh)	Mean Elect. Production (GWh)	Annual Heat Production (Tj)	Mean Heat. Production (Tj)
1998	2572.33	142.91	33,616.92	44.47	110,419.3	146.06
1999	2290.97	134.76	33,015.39	43.27	113,791.2	149.13
2000	2465.22	164.35	28,916.42	37.22	110,247.0	141.88
2001	1506.00	100.40	31,502.14	41.23	116,944.8	149.35
2002	1239.94	77.50	32,768.66	40.21	116,699.1	143.19
2003	132.03	7.76	40,092.94	48.95	116,440.8	142.17
2004	47.86	2.99	33,314.78	40.68	114,778.6	140.14
2005	66.05	2.64	29,154.22	34.26	113,780.9	133.70
2006	53.55	2.06	39,122.5	46.03	111,500.8	131.18
2007	76.31	2.18	31,701.86	37.61	103,269.7	122.51
2008	58.28	1.36	29,210.64	34.20	103,477.4	121.28
2009	55.81	1.24	29,302.30	34.19	102,648.6	119.78
2010	94.47	1.97	30,503.64	35.43	117,110.6	136.02
2011	69.00	1.33	24,954.08	29.43	101,690.1	119.92

[a] Authors own calculations.

Table 4.4: Share of Thermal Production by Generator Type (%)

	Electricity		Cogeneration	
Year	Capacity Elect. Production	Share Elect. Production	Capacity Elect. Production	Share Elect. Production
1998	10.72	7.11	89.28	92.89
1999	9.40	6.49	90.60	93.51
2000	9.34	7.86	90.66	92.14
2001	8.79	4.56	91.21	95.44
2002	6.30	3.65	93.70	96.35
2003	6.49	0.33	93.51	99.67
2004	6.47	0.14	93.53	99.86
2005	6.42	0.23	93.58	99.77
2006	6.41	0.14	93.59	99.86
2007	6.71	0.24	93.29	99.76
2008	6.89	0.20	93.11	99.80
2009	6.95	0.19	93.05	99.81
2010	6.95	0.31	93.05	99.69
2011	7.17	0.28	92.83	99.72

[a] Authors own calculations.

Table 4.5: Fuels Used by Thermal Generators

Fuel Type	Mean Number of Generators	Percentage of Generators	Mean production (Gwh)	Share of Fuel
Coal	21.93	2.61	48606.84	53.05
Natural Gas	563.78	66.46	23480.63	25.69
Waste	23	2.70	6436.73	7.21
Heavy Fuel Oil	33.86	4.02	2692.63	2.89
Straw	12.79	1.49	2192.51	2.45
Wood Pellets	2.36	0.27	1288.22	1.54
Wood Chips	11.07	1.28	1105.38	1.28
Biomass Waste	7.5	0.88	660.54	0.72
Bio Gas	144.57	16.93	834.15	0.93
Gas Oil	42.36	4.93	219.28	0.24

[a] Authors Own Calculation. A small set of generators used LPG, petroleum coke, waste oil orimulsion and refinery gas.

Table 4.6: Technology of Thermal Generators, Power Characteristics

Technology Type[a]	Number of Generators	Elect. Gen. Capacity (MW)	Agg. Elect. Gen. Capacity (MW)	Electricity Production (GWh)	Agg. Elect. Production (GWh)
Steam Turbine: Condensing	8	177.54	1,050.31	282.62	1,818.54
Steam Turbine: Extraction	14	369.13	4,911.26	1,483.37	19,638.98
Steam Turbine: Back Pressure	35	37.31	1,047.72	75.98	2,124.78
Steam Turbine: Waste to energy	18	10.65	181.86	65.64	1,122.73
Single Cycle Gas Turbine	29	13.40	330.65	49.50	1,233.14
Combined Cycle Gas Turbines	19	53.06	1008.12	199.02	3781.35
Gas Engine: Electricity	24	4.37	61.30	0.45	5.87
Gas Engine: Electricity and Heat	897	1.53	1,070.56	4.92	3,413.32
Emergency Power: Gas Engine	68	0.26	11.06	0.003	0.055

[a] Author's calculations. There were nine generators in the data set for which we could not identify the precise technology from the information provided in the data. However, these units did not produce electricity or heat during the period of analysis. These generators were omitted from the analysis. In addition, we do not calculate the costs for biogas engines, stirling motors or fuel cells (a total of 4 generators). These generators were too insignificant to include in the analysis.

Table 4.7: Technology of Thermal Generators, Heat Characteristics

Technology Type[a]	Heat Capacity (tj)	Agg. Heat Capacity (tj)	Heat Production (tj)	Agg. Heat. Production (tj)
Steam Turbine: Condensing	*NA*	*NA*	*NA*	*NA*
Steam Turbine: Extraction	310.51	4,129.61	2877.48	38,946.41
Steam Turbine: Back Pressure	90.61	2,552.96	685.28	19,087.33
Steam Turbine: Waste to energy	34.46	587.68	825.23	14,142.89
Single Cycle Gas Turbine	23.08	570.18	335.48	8,345.55
Combined Cycle: Back Pressure	32.51	476.48	523.38	7,686.67
Combined Cycle: Extraction	303.88	597.80	3,958.71	7,772.84
Gas Engine: Electricity	*NA*	*NA*	*NA*	*NA*
Gas Engine: Electricity and Heat	1.94	1,351.5	2.3	16,494.42
Emergency Power: Gas Engine	*NA*	*NA*	*NA*	*NA*

[a] Authors calculations. See table 4.6 for notes concerning missing data.

Chapter 5

Global Costs and Credits

5.1 Introduction

In this chapter, we explore the global costs and credits that apply to each generator or to different groups of generators. In particular, we first calculate the costs of the many fuels that have been used by the generators. Focusing on fuel costs provides an opportunity to study a substantial component of aggregate generating costs by comparing costs between fuel types and investigating any trends that may exist over time. Fuel costs make-up a substantial fraction of total generation costs which means that knowing how costs differ across fuels and how these costs have changed over time will help explain some of the variation in generating costs between generators as well as variation in generation costs over time. The costs of producing electricity for each type of thermal generator we introduced in chapter 4 using the methodology we described in chapter 3 are calculated in Levitt and Sørensen (2014).

Having explored fuel costs, we study a specific environmental cost borne by thermal generators: thermal generators emit carbon and because Danish electricity producers are part of the EU ETS system, they are required to have permits for each tonne of carbon they emit into the atmosphere. The carbon permits owned by the generators must be surrendered for each tonne of carbon emitted into the atmosphere. Additional permits must then be acquired to cover any new carbon emissions. Markets exist for trading carbon permits and trading (together with the cap-levels) have resulted in prices that have been quite volatile since the inception of the trading system. Because changes in carbon prices affect generation costs we provide a brief illustration of the progression of carbon prices since the beginning of the EU ETS.

In the last section of this chapter, we discuss an important issue specific to the class of generators that produce both electricity and heat (CHP generators): how to disentangle the costs of generating electricity and the costs of producing heat from total generating costs. Our solution to this problem, which is in fact the standard solution, is to calculate heat credits for each CHP generator. Heat credits are essentially the costs that would have obtained if the heat that was produced in the CHP unit was produced by an alternative heating plant. We compute the levelised costs of various district heating plants (heating plants differ by capacity and fuel) to calculate the heat credits. The heat credits can then be applied to individual CHP units. Computing heat credits for the individual generators, rather than adopting a more aggregate measure, is more complicated, but necessary. Importantly, the disaggregated approach allows us to compare electricity generating costs of conventional generators and CHP units as well as wind turbines.

5.2 Fuel Costs

We introduce our analysis of the costs of the fuels used by thermal generators by providing an overview of the costs by way of comparing long run trends. We report fuel costs in table 5.1. Note that the costs reported in table 5.1 are not yet the burner-tip cost because they have not been adjusted for the thermal efficiency of the generators that used the fuel. Thermal efficiencies vary across generators, even if they burn the same fuel, because of differences in technology and vintage; thermal efficiencies are generator specific.[1] The costs reported in table 5.1 were calculated using the formula

$$F_{ft} = \left(\frac{p_{ft} + s_{ft}}{\rho_{ft}} \right), \tag{5.1}$$

were p_{ft} is the price of fuel f in year t, s_{ft} is the transportation and insurance costs, and ρ_{ft} is the heat content of the fuel.

Table 5.1: Fuel Costs, 1985-2011 (kr/MWh)[a]

Year	Coal	Natural Gas	Fuel Oil	Gas Oil	Orimulsion	Straw
1985	111.38	312.45	288.55	390.89	NA	184.57
1986	80.44	306.48	101.88	213.79	NA	191.22
1987	60.72	412.52	121.85	173.76	NA	192.50
1988	61.95	305.86	76.20	139.05	NA	188.46
1989	71.26	308.07	93.48	166.07	NA	177.75
1990	63.32	337.62	88.03	182.76	NA	191.17
1991	63.38	330.70	73.22	182.37	NA	211.51
1992	57.20	321.88	75.84	153.39	NA	203.43
1993	49.59	241.88	68.37	164.42	NA	189.24
1994	46.48	191.54	85.30	146.51	NA	159.06
1995	47.62	189.28	75.52	128.93	44.47	193.08
1996	49.23	187.50	93.16	149.77	43.93	164.81
1997	57.05	159.69	85.77	155.25	46.48	164.60
1998	56.16	128.08	62.43	123.94	48.33	161.28
1999	46.34	115.85	198.23	136.92	45.10	156.83
2000	53.07	155.58	157.60	271.58	54.04	182.84
2001	68.78	152.67	127.57	236.04	56.00	174.43
2002	51.67	126.25	140.21	204.15	46.97	223.35
2003	50.99	138.32	130.82	209.47	302.67	206.01
2004	68.79	145.35	126.18	253.46	332.88	156.42
2005	70.80	165.59	182.14	347.37	NA	162.34
2006	67.61	189.27	200.91	362.86	NA	150.93
2007	70.30	192.05	259.69	339.17	NA	142.24
2008	98.47	211.63	360.69	410.17	NA	268.33
2009	81.82	190.67	280.87	277.18	NA	230.21
2010	91.04	216.63	295.79	352.63	NA	107.56
2011	102.86	218.64	350.60	440.22	NA	125.26

[a] The costs are reported in real 2011 Danish Kroner. See the corresponding sections for exact details of how these costs were calculated.

The costs reported in the table are quite interesting: there are two distinct periods in the 24 years of costs reported in the table. The first period, from 1985 to 1997, is characterized by decreasing costs, whereas, the second period, post 1997, is characterized by increasing fuel costs. Furthermore, the two periods are

[1] Fuel costs are adjusted for the thermal efficiency of the generators burning the fuel in the next chapter when the costs of specific technologies are computed.

distinguished by the differences in the relative costs of the fuels. Up until 1997, natural gas was much more costly compared to the other fuels; natural gas was almost three times more costly than coal, and almost twice as costly as gas oil and straw, which were the next costliest. However, during this period, natural gas prices were falling, so that by 1997, the cost of using natural gas was more inline with the costs of the other fuels. Although, starting in 2003, natural gas prices started to creep up, but still did not reach their pre-1990 levels by 2011. In the latter part of the second period (post-1997), the costly fuels have generally been gas and fuel oil. Indeed, the cost of fuel oil has risen quite substantially since 2004. Of course, coal, which was the dominant fuel over this period, was the least costly over the 20 plus years, and its long run trend is relatively smooth compared to the other fuels. Coal prices have been increasing since 2003.

A short note concerning orimulsion is warranted. Costs are reported in the table only for the years 1995 to 2004 because these are the only years in which Danish electricity producers used this fuel. For the first eight years that orimulsion was used by Danish producers, orimulsion was actually the least costly among the fuels. The costs are fairly similar to those of coal which is not surprising given that orimulsion is a coal product. However, in 2003 the costs of orimulsion increased substantially, so that it was the most costly fuel up until it was no longer used by Danish producers.

Changes in the cost of fuels have important implications for the aggregate costs of generating electricity precisely because expenditures on fuel is substantial. Knowing some of the reasons for the observed changes in the costs of the fuels leads to a better understanding of the costs of generating electricity. The formulae we used to calculate fuel costs (see equation (5.1)) illustrates that there are three potential causes for the observed changes in the costs reported in table 5.1: changes in fuel prices, changes in transportation or insurance costs, or changes in the heat content of the fuels. In general, there has been only small changes in the heat content of the fuels over this period. So, changes in the heat content of the fuels have not been the main catalyst for the changes in costs observed over time. Almost all of the changes are due to changes in prices and transportation costs. This is important because the prices of these fuels are determined in markets in which Danish electricity producers are only small participants. By small, we mean that the demand for the various fuels by Danish firms is very small relative to the aggregate demand for these fuels. The implication is that fuel prices are exogenous to Danish producers; that is, Danish firms do not have any influence over fuel prices. The bottom line is that Danish firms have very little control over prices.[2] In the remaining sections of this chapter, we describe the details of the fuel costs reported in table 5.1.

5.2.1 Coal

Recall that the dominant fuel used for generating electricity in Denmark is coal (see table 4.5). Denmark does not produce any coal since it does not have any commercially viable coal deposits. Consequently, all of the coal that is used to generate electricity must be imported. Most of the coal has historically been imported from Russia, South Africa, Colombia and Poland. Poland was an important source of coal for Danish electricity producers. In 2001, 30 percent of the coal used in generating electricity originated in Poland. More recently however, Poland's coal exports to Denmark have declined and their share has essentially been replaced by coal imported from the United States as well as larger deliveries from Russia. In 2009, 40 percent of Danish imported coal originated from Russia which is one of Denmark's largest suppliers (see Danish Energy Agency (2002) for a breakdown of the origins of coal imports in 2001 as well as Danish Energy Agency (2010) for the breakdown

[2]Electricity producers often implement strategies aimed at reducing the risks associated with fluctuating commodity prices. These typically involve participating in the various types of commodity markets: future markets is one example. In addition, fuels are often procured using contracts, both long-term and short-term, rather than purchased in spot markets. However, contracted prices are often tied to spot market prices. Consequently, contracted prices will have dynamics similar to spot prices.

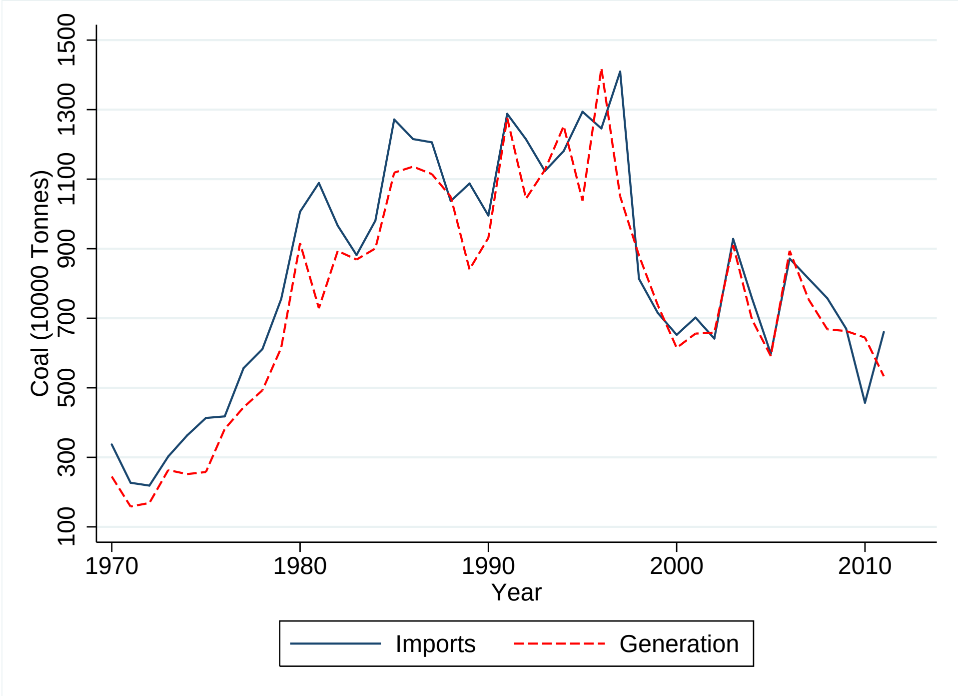


Figure 5.1: Coal Imports and Use in Electricity and Heat Generation, 1970-2011

in 2009). The fact that Denmark must import coal has important implications for electricity generation costs. The transportation costs of coal are not trivial: coal must be transported using large coal ships if the coal is being shipped via waterways or by train if the coal is begin shipped via land (compared to natural gas, for example, which is transported via pipelines).

In figure 5.1, we report the amount of coal imported annually between 1970 and 2011.[3] We also illustrate the amount of imported coal that was used for generating electricity and/or heat. From 1970 to 1985 coal imports grew at a fairly rapid pace from approximately 2.2 million tonnes in 1970 to about 12.7 million tonnes in 1985. During this period, on average 82 percent of imported coal was used for generating electricity and heat. There was a brief drop in imports during the early 1980s, but overall, imports grew at a rate of about 6 percent annually until the peak in 1985. It is clear from figure 5.1 that demand for imported coal as a source of fuel for generating electricity and heat was driving the growth in imports.

Post 1985, coal imports were still increasing up to 1998 when about 14 million tonnes of coal was imported. However, the growth rate was lower relative to previous years. Moreover, imports tended to more variable relative to the previous years. Coal imports tracked coal consumption by electricity and heat generation quite close during these years. Essentially, from the early 1970's to 1998 coal imports increased to largely meet the consumption needs of electricity and heat producers.

There was a significant decline in coal imports in the years immediately following 1998. Following the peak in 1998, which 14 million tonnes of coal was imported, coal imports fell significantly to less than 7 million tonnes in only a few years. The amount of coal imported into Denmark continued to decline so that the amount of coal imported in 2002 was almost the same as the amount imported in 1978: about 6.5 million tonnes. There were spikes in the quantity of coal imported in 2003 and 2006 which is consistent with the data presented in figure 4.4. There was a substantial increase in the consumption of coal in these two years and since Denmark

[3]Data on the aggregate quantity of coal imported and the use of coal for generating electricity and/or heat production were obtained from Statistics Denmark's Energy Accounts. Specifically, the data were obtained from account *ENE1N: Energy Accounts in physical units by industry and type.*

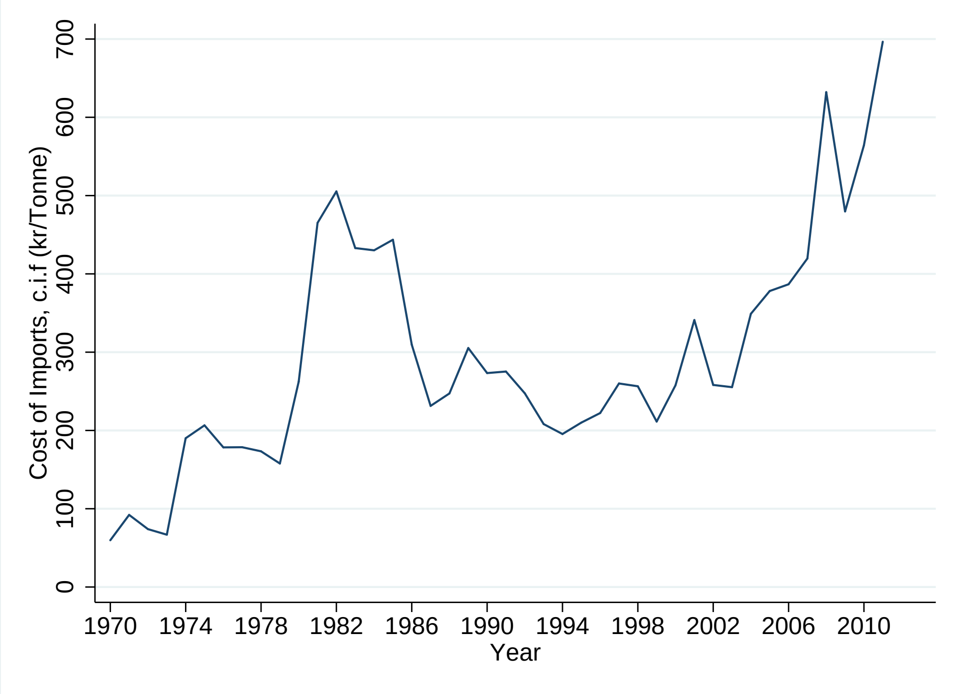


Figure 5.2: Cost of Coal Imports Used in Generation, 1970-2011

does not have a domestic source of coal these spikes in consumption were supplied by imports.

In general, from the early 1970's to the late 1990's the quantity of coal imported to feed electricity generators was increasing. Electricity and heat producers were importing more coal to meet increasing electricity and heating demands. Post 1998, however, there was a general decrease in the quantity of coal imported by Danish electricity producers. There are short one-year spikes in the consumption of coal, but the overall trend was that less coal was being used to generate electricity which reduced the demand for coal and led to less coal being imported.

All of the coal used in the generation of electricity in Denmark must be transported from the original mine to the generator actually burning the fuel. Electricity producers in Denmark must purchase the coal and then also pay the associated transactions costs of getting the coal to the generating plants. These transaction costs typically include freight, insurance costs and in some cases storage costs. These transaction costs are often significant. In figure 5.2, we present the aggregate cost of importing the coal used in the generation of electricity and/or heat. These costs include the actual purchase price of coal as well as transportation and insurance costs.[4] Because these data are realized expenditures, they are much more informative than spot market price (or prices of futures contracts). Moreover, one of the main difficulties of empirical studies concerning costs in the energy sector is obtaining data on the costs of freight and insurance. In our case, the expenditure data we use to calculate fuel costs included these important transaction costs.

The cost of importing coal has been increasing since at least 1970. Over this period there has been at least two episodes in which the costs of importing coal increased substantially. The first spike started in the late 1970s, culminating in a cost of over $500kr/tonne$ in 1982. By 1986, coal prices reverted back to pre-spike levels. From 1986 to 2003 coal prices did not show much of a long run trend but there were still short-lived annual fluctuations in the cost of coal. The second period of substantial increase in the cost of coal started in early

[4]The data reported in the figure 5.2 were calculated using data from Statistic Denmark's Energy Accounts. Aggregate coal expenses for coal used in electricity generation and/or heat production were obtained from account *ENE4N: Energy Accounts in monetary values by industry, unit and type.* The cost per DKK was obtained by dividing expenditure by the quantity of coal used in generating electricity and/or heat production.

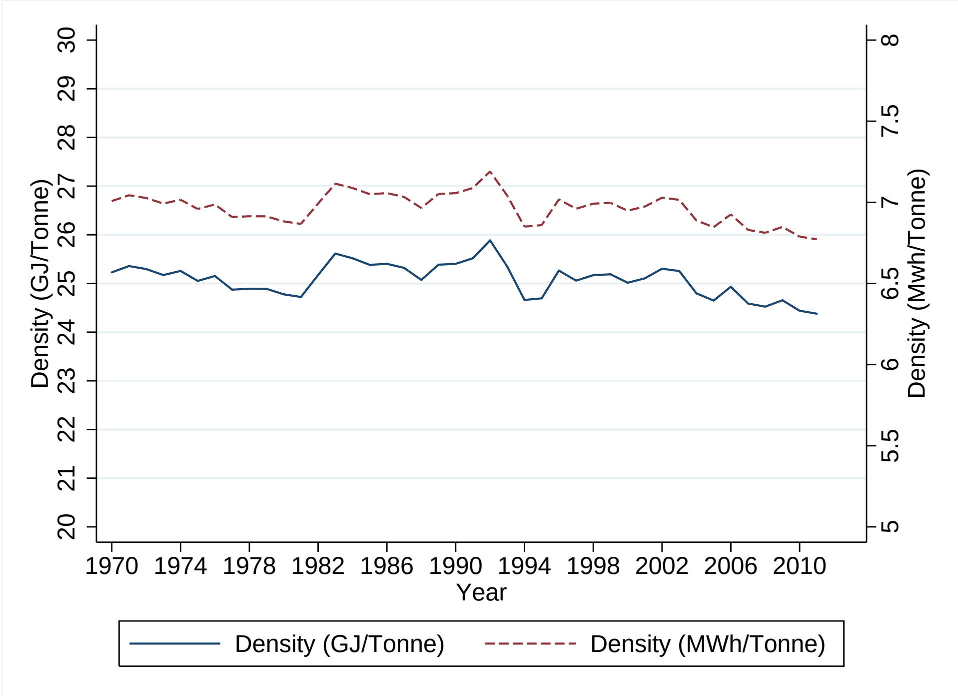


Figure 5.3: Coal Energy Density, 1970-2011

2000 and continued through to 2011. In 2011, the cost of coal was almost $700kr/tonne$.

Another important factor affecting the cost of using coal for generating electricity is energy density. The lower the energy density the more coal needed by generators to produce an equal amount of electricity. In figure 5.3, we illustrate the energy density of imported coal over the period.[5] We present the energy density in two different units: gigajoules per tonne ($Gj/Tonne$) as well as megawatt hours per tonne ($MWh/Tonne$).

Changes in energy density may be due to changes in the overall mixtures of the types of imported coal as well as to variation in energy densities within each type of coal. The lower is the energy density of the imported coal, the greater the quantity of coal that is required by generators to produce an equal amount of energy. Consequently, lower energy densities imply that more coal must be imported which increases purchase and transportation costs. The data reported in figure 5.3 indicate a modest, negative trend, in the energy density of imported coal. Also of importance is the annual fluctuation in the heat density of the imported coal. Even small changes in the heat density of coal can have large effects on costs because of the large quantity of coal being imported.

In a study on the historical costs of coal-fired electricity generation McNerney et al. (2011) calculated the energy density of coal used in the generation of electricity in the United States beginning in the 1920s and ending in the early 2000s. The energy densities reported in figure 5.3 are largely consistent with those reported by McNerney et al. (2011). In particular, they calculated energy densities ranging between $7.76MWh/Tonne$ in the 1950s to $6.47MWh/Tonne$ in the early 2000s. The energy density of coal used for generating electricity and/or heat in Denmark had a slightly higher energy density than the densities calculated by McNerney et al. (2011). McNerney et al. (2011) also found that the energy density of the coal used by generators in the United States were declining over time.

Adjusting the costs reported in figure 5.2 by the energy density of coal accounts for differences in the quality

[5] The energy density of coal was calculated using data from the Statistic Denmark's energy accounts. Data on the heat content of coal used in the generation of electricity and/or heat production was obtained from account *ENE2N: Energy Accounts in heating values (GJ) by industry and unit.* The energy density of coal is the ratio of the heat content of the coal used to generate electricity and/or heat to the quantity of coal used in generating electricity and/or heat production.

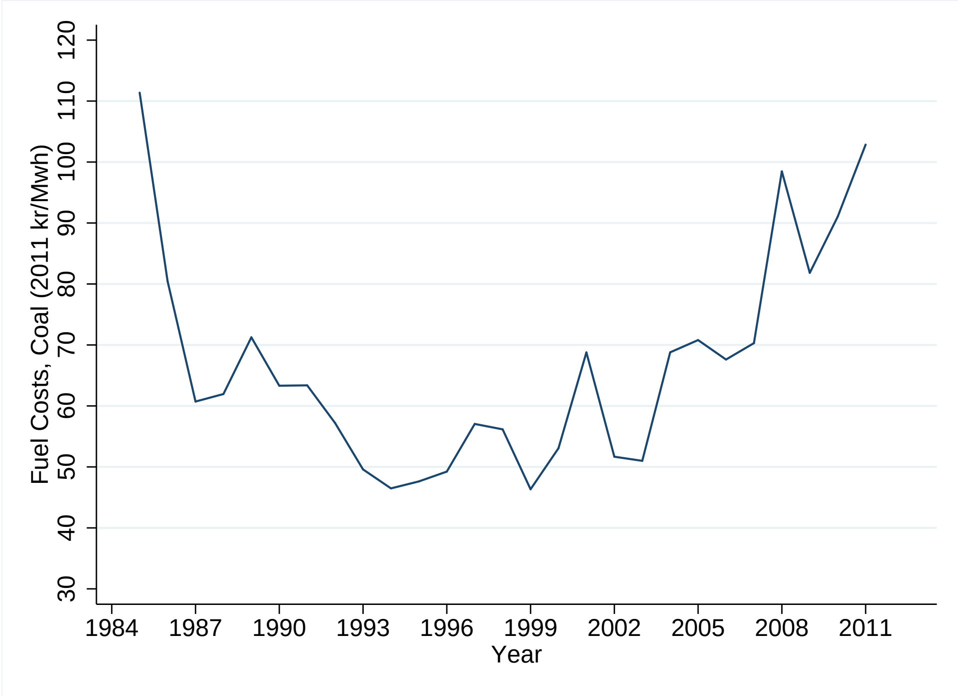


Figure 5.4: Fuel Costs, Coal 1984-2011

of coal and the type of coal that could be imported from different sources and any changes in coal quality or source of coal over time. Recall from chapter 3 that we calculate aggregate fuel using

$$F_{ft} = \left(\frac{p_{ft} + s_{ft}}{\rho_{ft} \times \eta_{gt}}\right).$$

The units of the costs are kr/MWh. Note that data concerning η_{gt} (thermal efficiency) has yet to be presented. This parameter is technology dependent and so we will discuss thermal efficiency when we calculate the costs of specific generating technologies. The cost of using coal as a fuel is reported in figure 5.4.

The dominant feature of the cost data presented in figure 5.4 is the U-shaped pattern reflecting a period of falling costs followed a period of increasing costs. Costs were decreasing since at least 1984. A substantial portion of the reduction in costs occurred prior to the 1990s. Costs started to gradually increase in the late 1990s. By the early 2000s, costs increased at a faster rate. A second important feature of the cost data is the existence of fairly substantial annual fluctuations. These annual fluctuations in the costs of coal means that the annual costs of coal-burning generators will fluctuate from year-to-year. Importantly, there are two reasons why coal costs are increasing post 1996. First, the costs of acquiring the coal has been increasing since the mid-1990s. Second, the heat content of the fuel has been decreasing since the mid-1990s. However, it is clear that expenditures on the purchase and transportation of coal are the most important factor affecting costs and that changes in energy densities are of a second-order effect. Notice also the the annual fluctuations are due to both the variability in the costs of acquiring the coal and the variability in the energy density of the coal.

5.2.2 Natural Gas

Natural gas is the second most dominant fuel, behind coal, burned by thermal generators to produce electricity. Recall from figure 4.9 that substantial investments in natural gas burning generators did not really start until the late 1980s. In fact, the Danish Energy Accounts report that no natural gas was used to generate of electricity

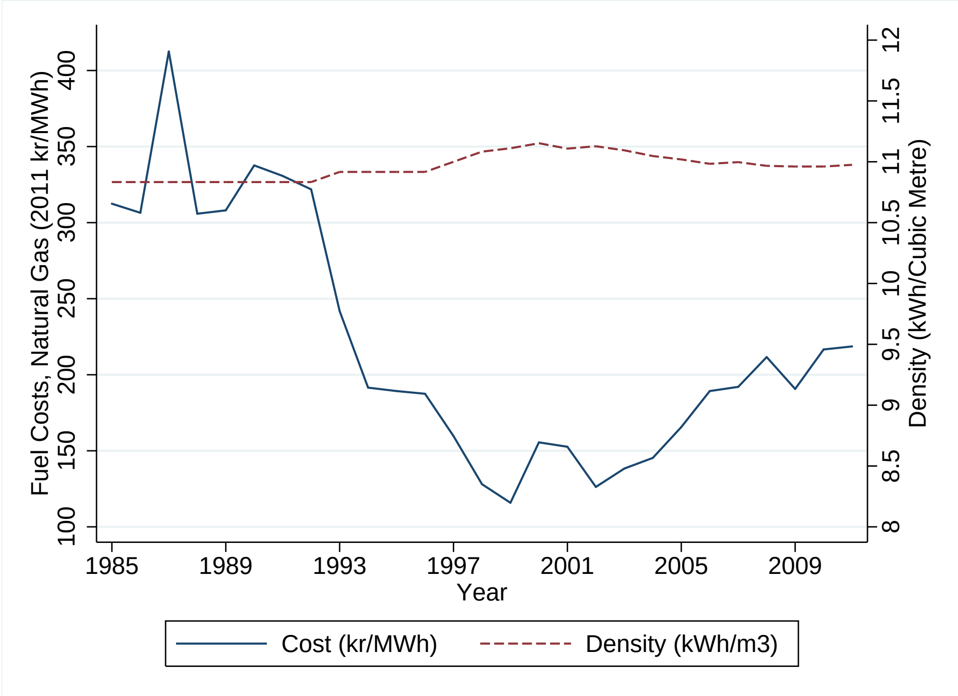


Figure 5.5: Fuel Costs, Natural Gas 1985-2011

prior to 1985.[6] Therefore, we examine the costs of natural gas over the the period beginning in 1985 and ending in 2011.

Denmark has a rich endowment of natural gas and until very recently, virtually all of the natural gas used in generating electricity had been sourced domestically. 2010 and 2011 were the first years in which substantial volumes of natural gas were imported; very little natural gas had been imported prior to 2010. Just over 144 million cubic metres of natural gas was imported in 2010, whereas 198 million cubic metres were imported in 2011.[7] Compared to the 6.8 billion cubic metres produced domestically in 2010 and 2011, the imported volume of natural gas is quite small. The transportation costs involved with getting the natural gas from processing plants to generators are generally less than the costs associated with shipping coal. Natural gas can be shipped through pipelines which reduces transaction costs relative to coal. Typically, electricity producers buy capacity on natural gas pipelines which they use to ship procured natural gas from processing or gathering facilities to generators. There are various types of capacity services that are generally offered together with different pricing mechanisms which often makes it difficult to construct costs without a host of simplifying assumptions.[8] Fortunately, we have data on realized expenditures on natural gas used for generating electricity which include acquisition prices as well as shipping and insurance costs.[9]

In figure 5.5, we report the fuel costs associated with burning natural gas to generate electricity. In addition, we report the energy density of the natural gas used to generate electricity. The costs reported in the figure have been adjusted for the energy density of the natural gas, so the units are kr/MWh. The energy density of the natural natural gas used to generate heat and electricity was relatively constant over the years ranging from $10.83 kWh/m^3$ to about $11.15 kWh/m^3$.[10] The only observable change in the heat content occurred in the

[6]See table *ENE1HT: Energy Account in Specific Units by Supply and Type of Energy* from Statistics Denmark.

[7]Once again, see table*ENE1HT: Energy Account in Specific Units by Supply and Type of Energy* from Statistics Denmark.

[8]For an interesting study on the burner-tip costs of natural gas used for generating electricity in California see Deaver (2013). The author of this report make a number of necessary simplifying assumptions concerning transportation costs.

[9]Aggregate expenses for natural gas used in electricity generation and/or heat production were obtained from account *ENE4N: Energy Accounts in monetary values by industry, unit and type*

[10]The energy density of natural gas was calculated using the same methodology we used for coal. The energy density of natural gas is the ratio of the heat content of coal to the volume of natural gas used in generating electricity and/or heat production. Data

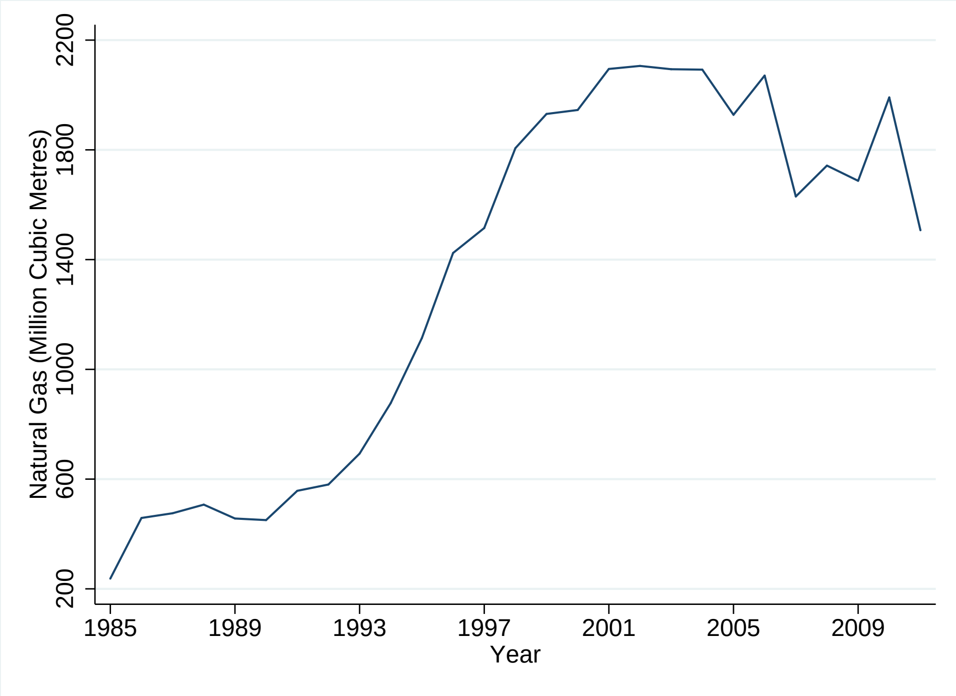


Figure 5.6: Use of Natural Gas 1985-2011

late 1990s and early 2000s during which the heat content increased, but only slightly. The energy density of the natural gas that we have calculated is consistent with the global average energy density of natural gas as reported by the United States' Energy Information Administration (EIA). The EIA reports a global average density of $10.66kWh/m^3$.[11] We can safely conclude that any changes in the observed costs of burning natural gas to generate electricity will not be due to changes in the heat content of the natural gas used to generate the electricity.

The costs reported in figure 5.5 are quite striking; there has been substantial changes in the costs of natural gas over the years. In particular, there was a prolonged period of decreasing costs starting from about 1990 and ending in 2000. The cost of natural gas in 1990 was $337kr/Mwh$ and in just under 10 years, the cost of natural gas was $115kr/Mwh$, a 66 percent decrease in costs. The almost decade long decrease in costs was followed by a decade long sustained period of increasing costs. The costs of natural gas in 2011 was $218kr/Mwh$, which was still much lower than those observed in the late 1980s and early 1990s. It is not surprising that the bulk of investments in natural gas burning generators occurred in the latter part of the 1990s (see figure 4.9) when natural gas costs were at their lowest and had been declining for a number of years. Moreover, the effect of changes in relative prices can also be seen in figure 5.6. The volume of natural gas used in the generation of electricity and heat started to increase quite significantly in 1990. Between 1990 and 2012, natural gas use increased by over 360 percent.

It is also interesting to note that the cost dynamics of coal and natural gas are similar. That is, each cost series has a similar U-shaped pattern: each has a period of sustained decreasing costs followed by a period of increasing costs. The reason for the similarities is that the two commodities are closely related in terms of the factors that affect supply and demand. Both are internationally traded commodities and their prices are determined by global supply and demand. Both are primarily used as energy inputs and so their prices respond

on the heat content of natural used in the generation of electricity and/or heat production was obtained from account *ENE2N: Energy Accounts in heating values (GJ) by industry and unit.*

[11]The EIA maintains a large database of related energy statistics which can be found at `http://www.eia.gov/`.

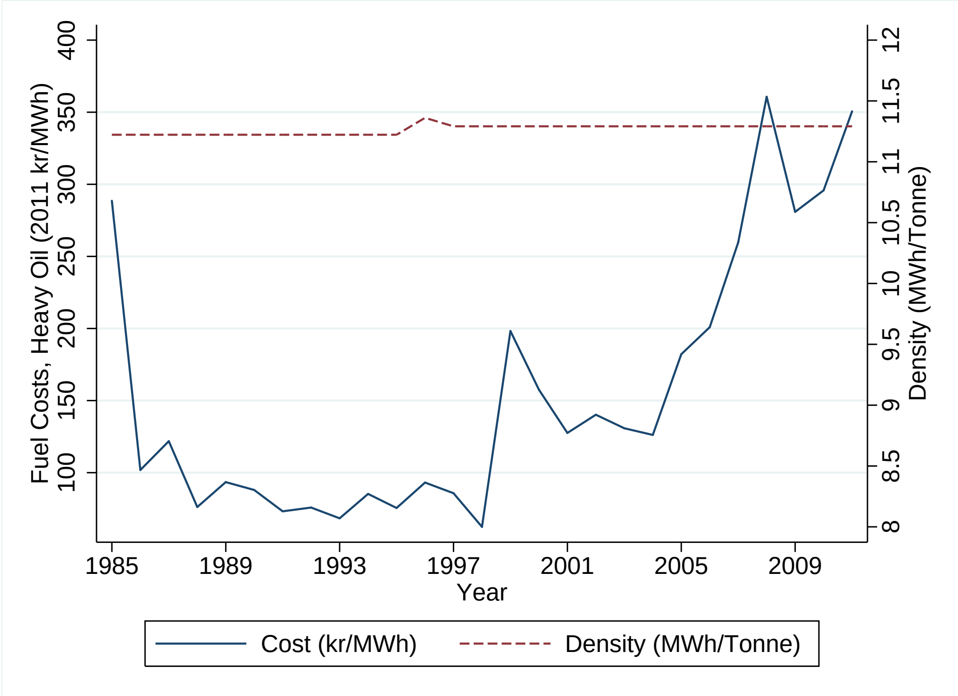


Figure 5.7: Use of Fuel Oil, 1985-2011

to changes in demand for energy. Moreover, the commodities are, to some extent substitutable, especially in the long run. This means, for example, that if the price of coal increases, then electricity producers may decide to substitute away from producing electricity using coal to producing electricity using natural gas generators. In the short run, the substitution could be achieved through changes in capacity utilization rates if slackness in capacity exists. In the long run, changes in relative prices could alter investment decisions; this seems to be the case in Denmark (this is just one factor that explains investment in natural gas generators observed in the latter part in the 1990s).[12]

5.2.3 Fuel Oil

Fuel oil is a fraction of petroleum (component of petroleum) that is obtained by separating the components of petroleum through condensation (called petroleum distillation). Fuel oil can be either a distillate or residue. One can think of fuel oil as any liquid petroleum product that is burned for the generation of heat to be used for heating purposes or for the generation of power. Fuel oil consists of six grades defined as number 1 fuel oil up to number 6 fuel oil. The grade of the fuel oil is determined by its boiling point and viscosity (the classification of the different grades of fuel oil can vary across organizations). For example, number 1 fuel oil is a volatile distillate with the lowest boiling point and highest viscosity (often called kerosene). Number 6 fuel oil is a high-viscosity residual oil that often requires preheating before it can be used in generators. Often, the low viscosity, residual fuel oils are blended with the high viscosity distillates, before it is used for generating heat or power. Typically, prices decrease as the fuel number increases. Note that in Europe, number 2 fuel oil is called gas oil (see the next section). Generally, heavy fuel oil refers number 4 fuel oil and above. Statistics Denmark does not report data for each grade of fuel oil or blends. Data is reported only for heavy fuel oil and gas oil. Generally, in terms of power generation, fuel oil refers to number 4 fuel oil and above whereas gas oil refers to number 2 fuel oil which is also called diesel.

[12]In an empirical study of interfuel substitution in the U.S. electricity sector, Ko and Dahl (2001) find that natural gas and coal are good substitutes having cross-price elasticities ranging from 0.5 to 2.3.

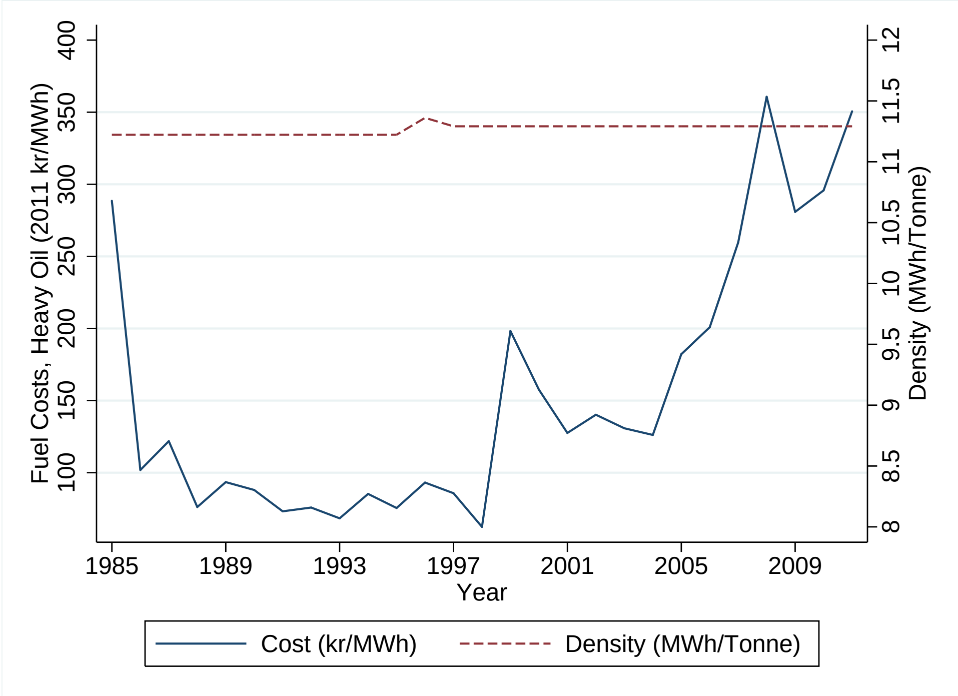


Figure 5.8: Fuel Costs, Fuel Oil 1985-2011

In figure 5.7, we report the quantity of fuel oil used in the production of electricity and heat. The use if heavy fuel oil to generate electricity and heat has been on the decline since at least 1984, with sharp drops in use in the latter part of the 1980s. In 1984, over 900 thousand tonnes of heavy fuel oil was used to generate electricity or heat. In only 6 years, just over 200 thousand tonnes of heavy fuel oil was used to produce electricity and heat, a decrease of over 75 percent. If a generator uses heavy fuel oil it is not typically the main fuel used by the generator. In most cases, a generator will use heavy fuel oil together with coal or natural gas. The decline in the use of heavy fuel oil is primarily due to generators burning more natural gas and straw. For example, the Avedore unit 2 generator built in 2001 can burn natural gas, heavy fuel oil, straw and wood pellets. Heavy fuel oil is among the dirtiest fuel with a carbon emission factor of around $0.28T/Mwh$ compared to $0.2T/Mwh$ for natural gas and $0.34T/Mwh$ for coal. One of the reasons producers substituted away from heavy fuel oil was the change in relative prices of natural gas and fuel oil together with environmental taxes.

The cost of fuel oil and the energy density of the fuel oil used for producing electricity and/or heat is presented in figure 5.8. The heat content of fuel oil has been essentially constant since 1985. This suggests that the mix of grades of fuel oil used in the production of electricity or heat has not changed. Different grades of the heavy fuel oil have different heat contents. Moreover, the changes in the costs of fuel oil illustrated in the figure have little to do with changes in the heat content of the fuel.

Interestingly, the costs shown in the figure follow similar patterns observed for the cost of coal and natural gas: a period of decreasing costs followed by a period of increasing costs. Similar to coal costs, there was an abrupt and significant decrease in the cost of heavy fuel oil. The cost of fuel oil decreased quite abruptly after 1985. In only one year, the cost decreased by 65 percent and by the end of 1988 cost decreased by 77 percent. Unfortunately, we do not have data for the years prior to 1985. Therefore, we do not know whether the cost in 1985 was part of a prolonged period of high prices or part of a short-lived spike in prices. Consequently, it is difficult to know whether the large decrease in costs observed in the two years after 1985 is really a significant change in the cost structure of heavy fuel oil.

A prolonged period of increasing costs began in 1998 after an almost decade-long period off relatively low

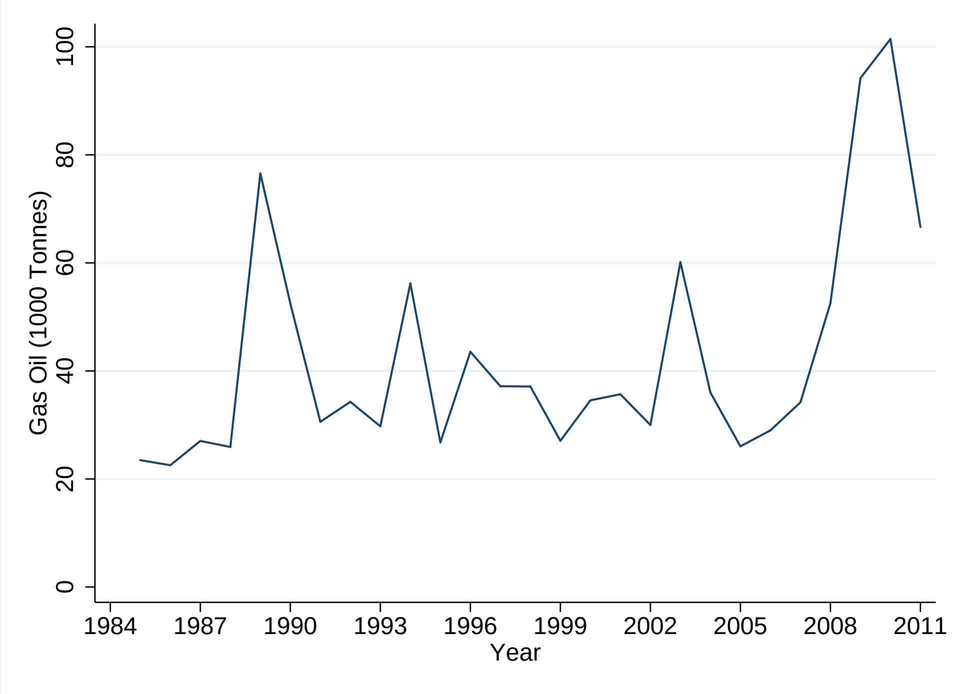


Figure 5.9: Use of Gas Oil, 1985-2011

costs (costs over this period were, on average, $81kr/Mwh$). In the ten years after 1998, costs increased by 480 percent, to a high of $360kr/Mwh$. In 2011, the cost of using heavy fuel oil to generator electricity was $350kr/Mwh$. Comparing figures 5.7 and 5.8 suggests that the low costs during the late 1980s and most of the 1990s spurred electricity producers to increase their use of heavy fuel oil. Once costs started to increase throughout the 2000s, the use of fuel oil declined. It is interesting, however, that the significant decline in the use of heavy fuel oil observed in the late 1980s corresponds to the significant decrease in the costs of fuel oil. This suggests that the decline in the use of fuel oil observed in the late 1980s was not motivated by changes in costs.

5.2.4 Gas Oil

As we briefly mentioned in the previous section, gas oil is also obtained from petroleum distillation and is often referred to as number 2 fuel oil in organizations outside of Europe. In general, number 2 fuel, and in some cases number 1 and 3 fuel oil, are categorized as gas oils in Denmark and throughout Europe, so we treat it separately. A good rule-of-thumb is to think of gas oil as the high viscosity, low boiling temperature petroleum distillates, whereas heavy fuel oils are distillates and residuals with low viscosity and often need to be pre-treated before they can be used in thermal generators. In addition, heavy oils are often blended with higher grade fuel oils. As we show in this section, there is good economic reason to analyze gas oil separately: gas oil is more costly than heavy fuel oils.

First, we look at how much gas oil has been used for producing electricity and heat since 1985. Gas oil is not used as extensively to produce electricity compared to the other fuels we study in this chapter. Not until 2006 has there been any significant increase in the use of gas oil. However, it is not clear how long-lived this increase in consumption will be given that use dropped off in 2011. Prior to 2006, there is a slight upward trend in the use of gas oil together with annual variations.

The cost of fuel oil and the energy density of the fuel oil used for producing electricity and/or heat is

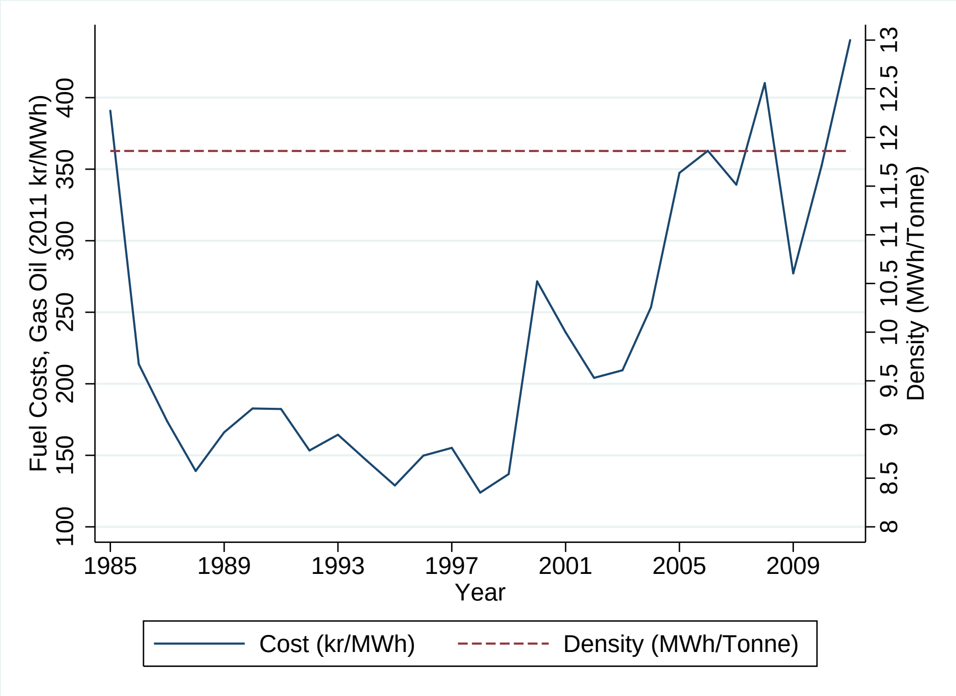


Figure 5.10: Fuel Costs, Gas Oil 1985-2011

presented in figure 5.10. Given that gas oil refers to specific grade of petroleum distillate which results in an homogenous product, compared heavy fuel oils for example, or even coal, we should not expect variation in the energy density of gas oil. Indeed, the energy density of gas oil used to generate electricity has been constant over the years. Also, because gas oil is a petroleum distillate, movements in its cost should be similar to those observed for heavy fuels. The main difference, of course, is that gas oil costs more. Comparing figure 5.10 with figure 5.8, we see that the two costs exhibit the similar trends over time and that the cost series for gas oil is essentially an upward shift of the series for heavy fuel oil.

5.2.5 Orimulsion

Orimulsion is a bitumen-based fuel that is made by mixing bitumen with fresh water and a surficant.[13] In the case of orimulsion, the surficant works to help solubilize the bitumen which has an extremely high viscosity. The high viscosity of the bitumen, before it is treated, renders it unsuitable for direct use in conventional electricity generators. Once the bitumen is treated with the surficant and turned into orimulsion it has similar characteristics as heavy fuel oils. Orimulsion was developed and is currently only produced in Venezuela.

Danish electricity producers only used orimulsion for a few years, 1995 to 2004. Since orimulsion was produced only in Venezuela, all of the fuel used by Danish generators had to be imported. In 1995, just under 800 thousand tonnes of orimulsion was used to generate electricity and heat. Imports peaked in 1997 when 1.4 million tonnes were used to generate power and heat. The use of orimulsion started to decline post 1997 and continued to do so until 2004. The last year in which orimulsion was used as a fuel in Danish thermal generators was 2004.

We calculate the costs of orimulsion for the 10 years it was used by Danish power producers. The costs are presented in figure 5.11. The most interesting characteristic of these cost data, which is quite different from the costs we previously calculated for the other fuels, is that they are relatively constant until 2002. The

[13] A surficant is a compound that lowers the surface tension between a liquid and a solid.

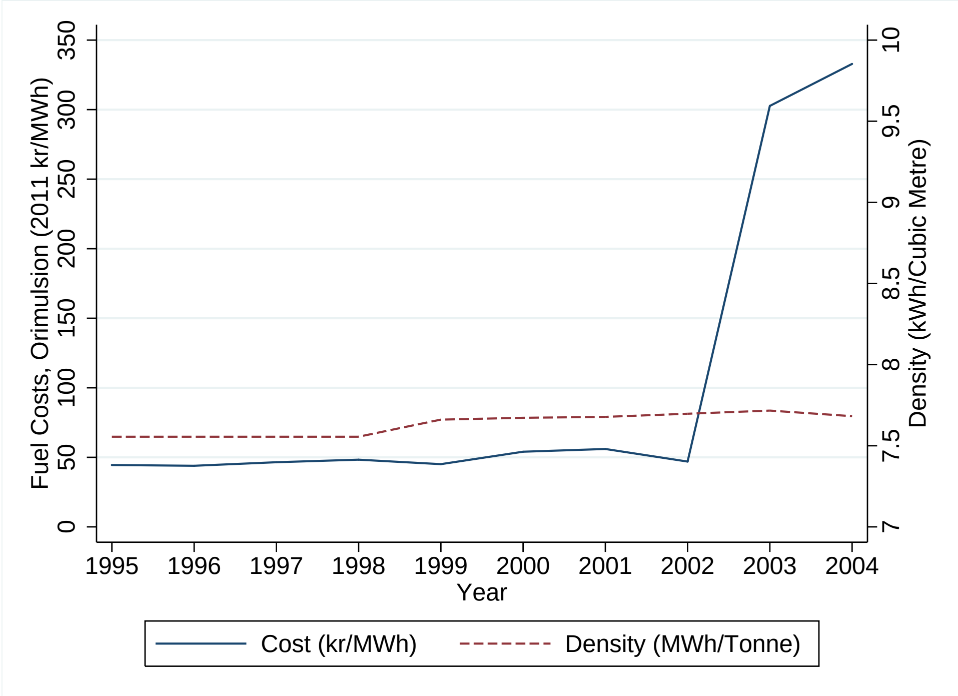


Figure 5.11: Fuel Costs, Orimulsion 1985-2011

distinctive U-shaped pattern observed of other fuels does not exist for orimulsion. In particular, the average cost of orimulsion between 1994 and 2002 was about $48kr/MWh$ with a standard deviation of only $4.4kr/MWh$. The primary reason that costs did not move that much during this period is that Danish producers entered into long-term contracts which stipulated contracted prices. The market for orimulsion would have operated differently relative to global commodities, like coal and natural gas, because it was essentially being supplied by a single producer. The last two years saw a tremendous increase in the cost of orimulsion. Cost jumped by over 600 percent in the last two years the fuel was used. However, the large increase in the cost of orimulsion will have little influence on aggregate costs because little orimulsion was used to generator electricity in these two years.

5.2.6 Straw

Straw is among the fuels which their use in electricity generation has increased since 1985 (waste and other wood products are the others). Between 1985 and 2011, the consumption of straw for generating power and heat increased by almost 880 percent. In 1985, about 104 thousand tonnes of straw was used to generate electricity and heat, whereas in 2011 over one million tonnes were used. Interestingly, there does not seem to be a particular year or short period in which the use of straw to produce power took off. That is, the rate at which the consumption of straw increased was fairly consistent over time.

The costs of using straw to produce electricity is presented in figure 5.13. Because straw is essentially an homogenous fuel, the heat content of the straw used to generate power has been constant over the years. There is an interesting result when comparing costs over time to the consumption of fuel straw illustrated in figure 5.12: there is no clear long run increasing or decreasing trend in costs; however, the cost of straw has become more variable as the quantity of straw used to generate electricity has increased. Annual variation in costs was especially evident in the latter part of the 2000s. For example, in 2008, the cost of straw increased by over 88 percent. However, in just two years costs decreased by almost 70 percent.

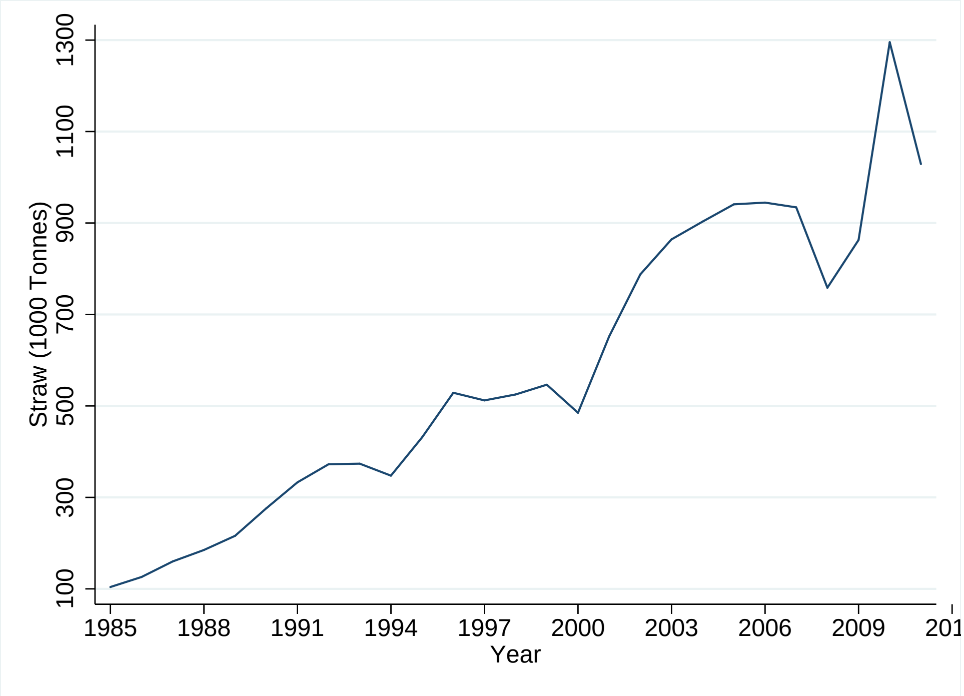


Figure 5.12: Use of Straw, 1985-2011

The lack of a increasing or decreasing long run trend in costs of straw suggests that their costs will have little influence over the long run costs for those generators that used straw. But, the annual fluctuations in costs will affect annual generation costs of generators. However, some generators that used straw also used other fuels to generate electricity, so the effect of the annual fluctuations will depend on straw's share of aggregate fuel use for each generator. Given that straw use has increased over time, the affect on aggregate is likely increasing as well.

5.3 Carbon Prices

In this section, we move away from studying fuel costs and look at another global cost paid by thermal generators: the cost of their emissions. Generators are subject to various environmental regulations which increase the costs of generating power. One specific regulation that Danish power producers have been influenced by is the EU ETS. Under the EU ETS, generators are required to hold permits for the carbon they emit into the atmosphere. These permits have prices and are traded in markets. A power producer must remit one carbon permit for every tonne of carbon it emitted into the atmosphere. If a producer does not have enough permits to cover all their carbon emissions they must purchase additional permits. On the other hand, of the producer has unused permits it can either bank these permits (carry them into the next period) or sell them.

The spot-market price of these permits is reported in figure 5.14. Price initially started trading at over $160kr/Tonne$, However, in only two years, prices dropped significantly to less then $5kr/Tonne$. In 2009, price increased back up to around $100kr/Tonne$ were it remained to at least 2011.[14] There have been some interesting studies about the price of carbon within the EU ETS system. Those who wish to have a better understanding the prices reported in figure 5.14 can have a look at Alberola et al. (2008), Ellerman and Buchner (2008) as

[14]The prices for emission permits are the completed settlement prices as reported by the European Energy Exchange. The data was obtained via *Datastream* which is a database service provided by Thomson Reuters. The name of the series in the *Datastream* database is *EEX-EU CO2 Emission Settlement Prices*. The data was reported in Danish Kroner per metric tonne ($kr/MTonne$) at the monthly level. Annual prices were obtained by taking the mean of the monthly prices.

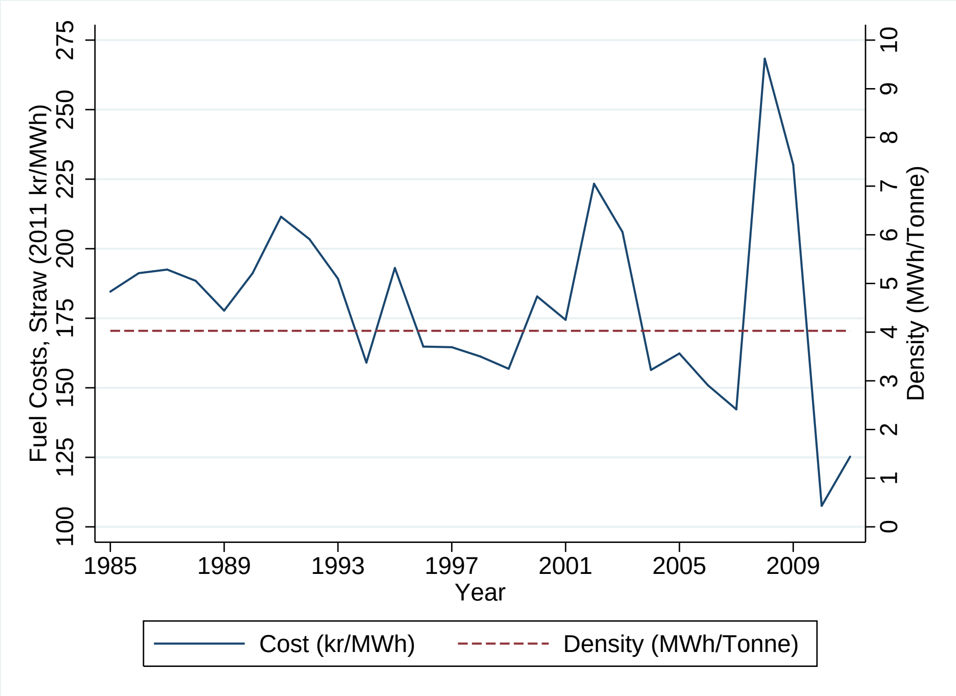


Figure 5.13: Fuel Costs, Straw 1985-2011

well as Hintermann (2010).

5.4 Heat Credits

As we described in chapter 4, CHP generation is the cornerstone of the Danish power system; more than 95 percent of thermal electricity is generated by CHP plants. Therefore, a study of the costs of generating electricity in a power system consisting of a large number of CHP plants must recognize the benefits of CHP generation: potentially wasted heat is transformed into usable heat substantially increasing the efficiency of generation. The difficulty is that the production costs associated with CHP plants can be attributed to the generation of electricity as well as to the production of heat. We calculate the costs of CHP generation in Levitt and Sørensen (2014) by separating thermal generators into condensing (no heat production), back-pressure (constant electricity to heat production ratio) and extraction (variable electricity to heat production ratio) generators. It is vital that we account for heat production in these cost calculations otherwise it is impossible to compare the costs of generating electricity by different technologies. Clearly, the costs associated with generating heat must not be included in the costs of generating electricity. However, assigning costs to either generating electricity or producing heat is difficult because they are produced at the same time. For example, we observe the aggregate amount of fuel a generator housed in a CHP plant has burned to produce heat and generate electricity, but how should we assign the burner-tip costs between the two processes? It is wrong to assign all of the burner-tip costs to the generation of electricity since doing so implies that the cogenerated heat has no value, which is clearly not true.

The standard approach to calculating the costs of generating electricity by a CHP generator is to calculate heat credits. Computing heat credits allows for the costs of generating electricity to be determined because the implied costs of generating the heat can be deducted from the aggregate production costs of the CHP unit. More precisely, heat credits are the costs that would have obtained if the heat produced by a CHP plant was instead produced by an alternative heat-only generator. How to calculate heat credits? In order to calculate heat

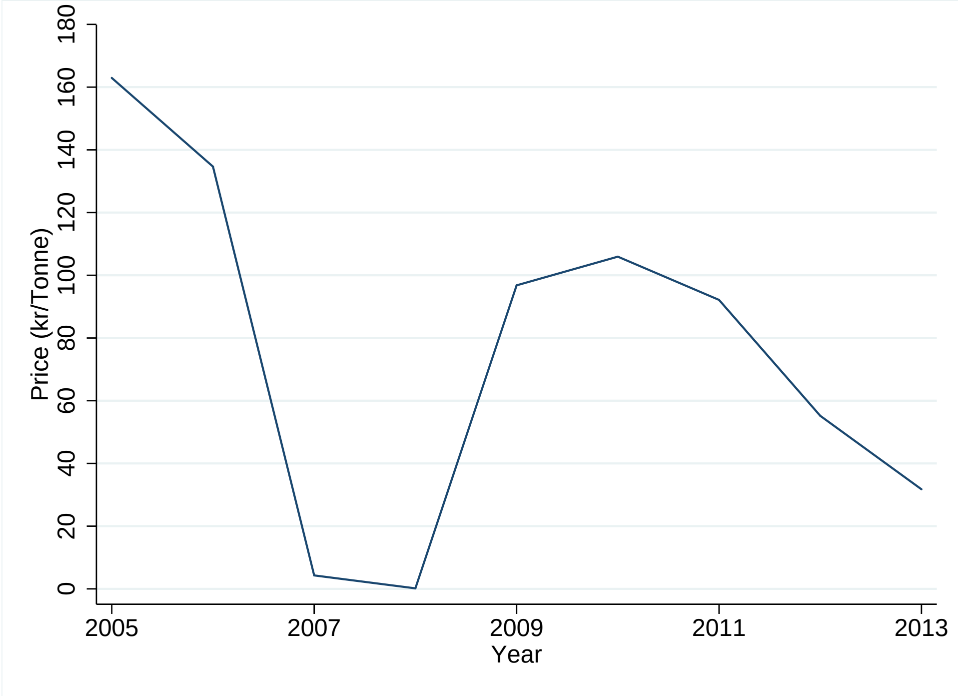


Figure 5.14: Carbon Emissions Price, 2005-2013

credits, assumptions concerning the hypothetical replacement technology must be made. An important issue, for example, concerns whether existing plants can replace the heat produced by CHP plants or must additional capacity be considered? What type of technology should be considered? What fuel will the hypothetical plant burn? These types of decisions must be made in order to calculate heat credits.

Of course, we make informed choices concerning each of these assumptions. We chose the simplest replacement technology: a district heating boiler burning either coal or natural gas. In addition, we used the existing characteristics of the CHP generator, to the extent possible, to determine the characteristics of the replacement boiler. For example, the size of the replacement boiler was determined by the heat capacity of the CHP unit (For each generator in our data, we observe their electricity generating capacity as well as their heat producing capacity). The type of fuel burned by the hypothetical boiler was determined by both the size of the CHP unit as well as the primary fuel burned by the CHP unit.

We start with the basic assumption that the heat produced by a CHP plant is replaced by a district heating boiler. We do not assume that the heat produced by CHP plants can be replaced by existing plants; it is unreasonable to assume that there is enough slack capacity in the district heating system to replace the heat produced in the CHP plants. We assume that additional capacity is required to replace the heat generated by CHP plants. Therefore, we calculate the levelised cost, including capital costs, of these hypothetical district heating plants. The levelised cost of each replacement boiler determines the heat credit for the CHP plant. The type of district heating boiler that is assumed to replace CHP heat is determined by the heat capacity of the CHP generator. In particular, CHP plants that have a heat capacity less than $50MW$ and did not use coal as its primary fuel is assumed to be replaced by district heating natural gas boiler. The heat produced by CHP generators with heat capacities greater than $50MW$ or used coal as its primary fuel was assumed to be replaced by equivalent sized coal-burning boiler. Finally, heat produced form waste-to-energy plants is assumed to be replaced by waste-to-heat district boilers.

Overnight costs were assigned to each type of boiler based on size. We use the costs reported in the 2005 and 2014 Danish Technology Manual (Danish Energy Agency (2005) and Danish Energy Agency (2014)) in our calculations. The overnight costs for a boiler having a heat capacity less than $1MW$ is $kr0.68M_{2011}/MW$; a boiler with a capacity greater than $1MW$ but less than or equal to $5MW$ has an overnight costs equal to $kr2.32M_{2011}/MW$; the overnight costs for a boiler with a heat capacity between $5MW$ and $10MW$ is $kr3.52M_{2011}/MW$; finally, for boilers having a capacity greater than $10MW$, costs equal $kr8.19M_{2011}/MW$. The capital recovery factor is calculated under the assumptions that the age of the boiler is identical to the age of the CHP plant, and that the interest rate is equal to the one used to calculate the levelised cost of the CHP generator (more detail concerning interest rates are provided in the next chapter). The final component of capital costs is the capacity factor: we assume that the capacity factor is equal to 0.70.

Burner-tip costs for the hypothetical boilers were calculated using the fuel costs presented in this chapter. We assume that the efficiency rate of the boilers is 0.96 (as reported in the the Danish Technology Manuals (Danish Energy Agency (2005) and Danish Energy Agency (2005)). We assumed that boilers with a capacity greater than $50MW$ are coal-fired boilers. In addition, district heating boilers that are replacing the heat produced by CHP generators which primarily burned coal, are also coal-fired. All other boilers are assumed to use natural gas.

Operation and maintenance costs are assigned to each hypothetical boiler based on capacity: boilers with a capacity less than $50MW$ have a total operation and maintenance costs equal to $kr4.19/MWh$, whereas the operation and maintenance costs for boilers having a capacity greater than $50MW$ equals $kr87.93/MWh$.

The final calculations involve environmental costs. Environmental costs were calculated using the carbon prices illustrated in section 5.3 of this chapter together with the emission factors for coal and natural gas. The mean environmental costs for large boilers (capacity greater than $50MW$) is about $kr15/MWh$. However, the costs have a fairly large range due to variation of the price of carbon: the lowest cost is of course zero (period prior to 2005), whereas the largest cost is $kr55/MWh$. The average environmental costs for small boilers (heat capacity less than $50MW$) is approximately $kr9/MWh$ with a maximum cost equal to $kr33/MWh$.

The heat credit for each generator is then calculated as the sum of capital costs, burner-tip costs, maintenance and operation costs, and environmental costs. The average heat credit (reported in real values) across all hypothetical replacement boilers is $kr225.64/MWh$ with a standard deviation equal to $kr62.95/MWh$. The smallest credit equals $kr130.02/MWh$, whereas the largest credit equals $kr578.44/MWh$. We report the heat credits specific to each class of thermal generators in the next chapter.

Chapter 6

Aggregate Costs

6.1 Introduction

In Levitt and Sørensen (2014), we computed the levelised costs of generating electricity for various classes of thermal generators as well as for both offshore and onshore wind turbines. In this chapter, we combine these costs to compute measures of the aggregate costs of generating electricity in Denmark and provide an analysis of these measures. First, we compute the aggregate per unit cost of generating electricity in Denmark. Following these calculations, we do a counterfactual investigation of what generation costs would have been in the absence of wind turbines. In addition, we compute the aggregate expenditure on electricity generation. For both measures, we highlight the main contributors to aggregate costs as well as track the evolution of costs since 1998 and discuss some of the causes of the observed changes.

We also provide in this chapter a brief look at system-wide costs. These are the costs of managing the distribution and transmission grid as well as ensuring a stable and secure supply of electricity. Moreover, not all of the electricity generated in Denmark is consumed domestically and not all of the electricity consumed in Denmark is generated domestically. There is an active international market for electricity generated in Denmark. Some of the electricity generated in Denmark is exported to Germany, Norway and Sweden generating revenue. Moreover, Denmark imports electricity from these three countries. In section 6.5, we look at imports of foreign electricity and exports of Danish electricity. In the final section of this chapter, we calculate a measure of the costs of electricity consumed in Denmark. This cost measure accounts for system-wide costs as well as for international trade.

6.2 Generation Costs

In the previous chapters we calculated the levelised costs of generating electricity for the different classes of generators in Denmark. We report the average contributions to aggregate per unit costs in table 6.1. In addition, in the last column, we report the aggregate per unit cost which is the sum of the contributions. Understanding the units in which both the electricity data as well as the costs are reported is important for interpreting the results (see chapter 3 for additional details concerning units and their interpretation). Briefly, the costs reported in table 6.1 are in kroner per MWh and should be interpreted as average per unit costs. More precisely, the per unit costs reported in the table are the weighted averages of the costs of generating a MWh of electricity. The average is taken over all of the individual thermal generation units and the individual wind turbines. The weights used to calculate the weighted average are each generator's share of aggregate electricity production.

So, in summary, aggregate per unit average costs, denoted by C_t, are

$$\begin{aligned} C_t &= \sum_{i=1}^{N} \frac{g_{it}c_{it}}{G_t} \\ &= \sum_{i=1}^{N} s_{it}c_{it} \end{aligned}$$

were the i, t subscripts specify a generator and year respectively; g_{it} denotes the amount of electricity generated by generator i in year t; c_{it} is the per unit cost of generating electricity by generator i in year t (units are kr/MWh); G_t is aggregate generation in period t. In the last equality, s_{it} denotes generator i's share of aggregate generation. Finally, generator-specific costs, c_{it}, are those that were calculated in Levitt and Sørensen (2014).

It should not come as a surprise that the extraction and back-pressure generators had the largest share of aggregate costs. Although, extraction generators were the dominate contributors to overall costs. In fact, the contributions made by extraction generators were, in some years, more than double those of the back-pressure generators. The levelised costs of extraction generators were less than most of the other thermal generators (the levelised costs were greater than the costs of wind turbines). So, their large contributions were not due to higher generation costs relative to the other generators, but to the fact that extraction generators produced a large share of total electricity output. However, the large share of production also implies that changes in the costs of generating electricity from extraction generators will have larger effects on aggregate costs relative to the other generators.

The circumstance surrounding back-pressure generators was a little different compared to extraction generators. Back-pressure generators produced a significant share of total electricity; however, other classes of generators generated more electricity. The main reason for their large share of aggregate costs was their relatively large costs compared to the other classes of generators (except condensing generators). So, back-pressure generators had a relatively large share of aggregate costs because the electricity they produced was high cost and they supplied a significant share of aggregate electrical output.

A clearer picture of the distribution of aggregate costs across the different classes of generators emerges from the data reported in table 6.2. We report in the table the share of aggregate costs for each generator in each year. There are a number of interesting results that emerge from the table. First, as noted previously, extraction generators contributed the largest share to aggregate cost. Over the 14 years, they have, on average, contributed over 30 percent to aggregate costs. Back-pressure generators were the next largest contributors to aggregate costs.

The second interesting feature is that the distribution of costs had changed over the 14 years. Specifically, we observe the emergence of wind turbines. The share of aggregate costs of both the condensing and back-pressure generators had declined over the period, whereas the share of wind turbines and combined-cycle generators increased. Indeed, in 2011, wind turbines' contribution to aggregate costs surpassed those contributed by all other generators with the exception of extraction generators. The contributions made by extraction generators, CHP waste plants, gas turbines, and gas engines did not change substantially over the period.

Because the costs reported in table 6.1 are production weighted averages, there are two possible explanations for the changes observed in table 6.2. First, the costs of generating electricity for a generator could have changed;

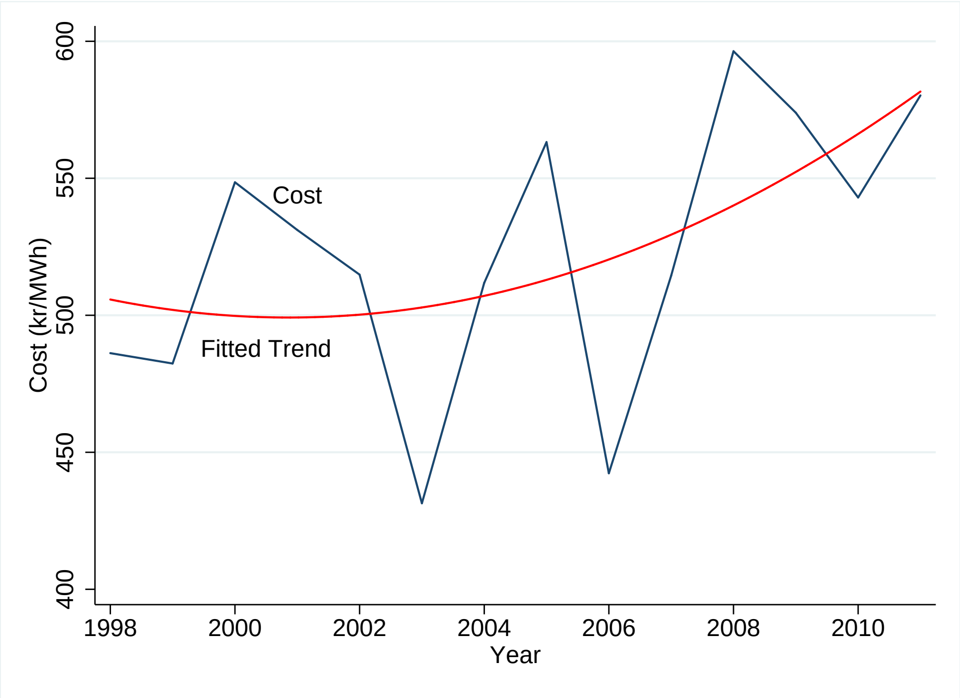


Figure 6.1: Aggregate Generation Costs, 1998-2011

Table 6.1: Contributions to Aggregate Generation Costs, 1998-2011 (kr/MWh)[a]

Year	Steam Turbine: Condensing	Steam Turbine: Back Pressure	Steam Turbine: Extraction	CHP Waste	Combined Cycle	Gas Turbine	Gas Engine	Land Turbines	Offshore Turbines	Aggregate Cost
1998	100.32	96.98	156.90	9.14	15.69	27.08	40.44	39.07	0.56	486.18
1999	87.22	93.51	163.25	9.42	15.95	27.50	40.05	44.95	0.56	482.40
2000	99.05	97.17	171.44	10.26	22.63	33.79	50.26	62.11	1.83	548.55
2001	89.59	92.40	165.39	9.76	29.39	31.98	49.20	61.49	1.95	531.15
2002	84.65	95.32	150.78	9.63	32.11	27.60	43.93	65.51	5.31	514.83
2003	55.74	78.41	129.90	8.03	31.75	24.59	38.39	53.65	10.94	431.40
2004	57.34	86.64	171.05	10.29	35.01	30.61	44.67	62.56	13.65	511.83
2005	63.31	89.14	189.40	11.26	41.07	34.21	50.74	68.10	15.98	563.21
2006	58.11	68.61	130.84	9.23	40.10	29.31	41.25	52.48	12.40	442.34
2007	60.87	67.51	174.74	11.32	45.61	31.40	45.64	62.90	14.45	514.44
2008	64.02	82.58	204.46	12.97	57.40	37.80	52.31	68.81	16.04	596.38
2009	54.59	95.91	194.17	12.30	47.33	31.76	48.22	68.07	21.56	573.93
2010	53.47	76.05	189.19	10.69	40.49	31.47	51.44	63.88	26.31	542.98
2011	54.55	81.65	201.87	11.79	40.79	32.42	51.47	74.17	31.54	580.25

[a] Costs are reported in real 2011 Danish Kroner.

Table 6.2: Contribution Percentages, 1998-2011 (%)

Year	Steam Turbine: Condensing	Steam Turbine: Back Pressure	Steam Turbine: Extraction	CHP Waste	Combined Cycle	Gas Turbine	Gas Engine	Land Turbines	Offshore Turbines	Aggregate Costs
1998	20.64	19.95	32.27	1.88	3.23	5.57	8.32	8.04	0.12	100
1999	18.08	19.38	33.84	1.95	3.31	5.70	8.30	9.32	0.12	100
2000	18.06	17.71	31.25	1.87	4.13	6.16	9.16	11.32	0.33	100
2001	16.87	17.40	31.14	1.84	5.53	6.02	9.26	11.58	0.37	100
2002	16.44	18.51	29.29	1.87	6.24	5.36	8.53	12.72	1.03	100
2003	12.92	18.18	30.11	1.86	7.36	5.70	8.90	12.44	2.54	100
2004	11.20	16.93	33.42	2.01	6.84	5.98	8.73	12.22	2.67	100
2005	11.24	15.83	33.63	2.00	7.29	6.07	9.01	12.09	2.84	100
2006	13.14	15.51	29.58	2.09	9.07	6.63	9.33	11.87	2.80	100
2007	11.83	13.12	33.97	2.20	8.87	6.10	8.87	12.23	2.81	100
2008	10.74	13.85	34.28	2.18	9.62	6.34	8.77	11.54	2.69	100
2009	9.51	16.71	33.83	2.14	8.25	5.53	8.40	11.86	3.76	100
2010	9.85	14.01	34.84	1.97	7.46	5.79	9.47	11.76	4.85	100
2011	9.40	14.07	34.79	2.03	7.03	5.59	8.87	12.78	5.44	100

[a] Authors own calculations.

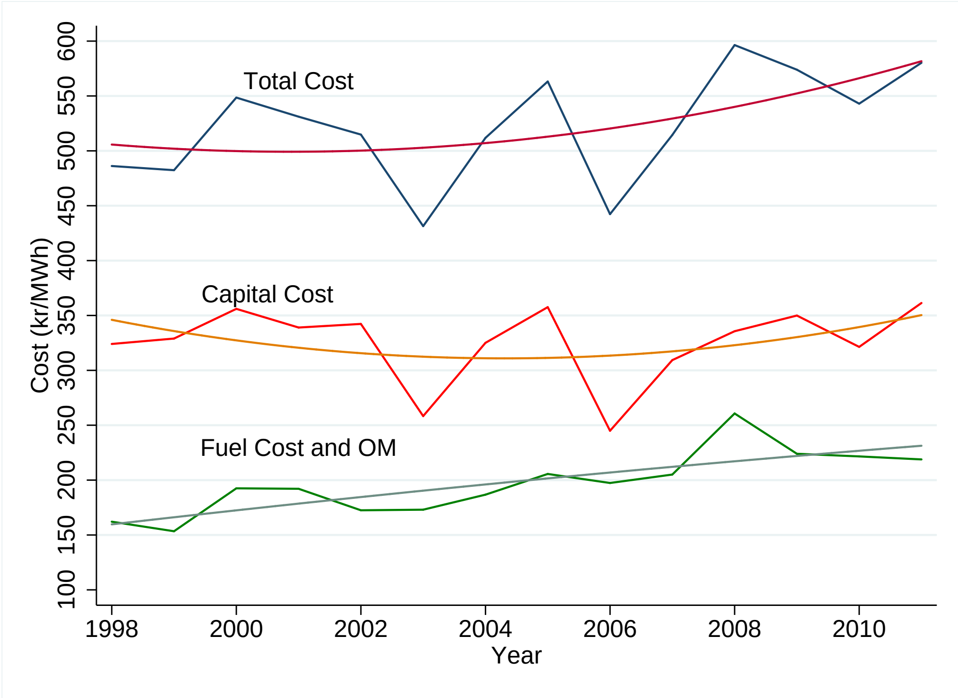


Figure 6.2: Aggregate, Fuel and Capital Costs, 1998-2011

and second, the generator's share of aggregate electricity production could have changed. Wind generation provides an interesting example: Generation costs have generally been decreasing for both offshore and onshore turbines since the early 2000s; however, their contributions to aggregate costs increased over the same period because their share of aggregate electricity generation increased. Therefore, in table 6.2, we observe that the wind turbines' share of aggregate costs had increased over the period.

The evolution of average costs over time are illustrated in figure 6.1 together will a fitted quadratic trend curve. It is clear that costs had been increasing since 2000 with the rate of change increasing over time. The increase in costs were due to either increasing fuel costs, increasing capital costs, or a combination of the two. To determine the relative importance of fuel costs and capital costs, we look at the contribution each major cost component made to aggregate costs in figure 6.2. The other interesting characteristic illustrated in figure 6.1 is that there was substantial annual variation in costs. In particular, there were significant drops in costs in 2003 and 2006. These were the result of increases in capacity factors which had the effect of reducing capital costs in these years. The increase in capacity factors were due to a decline in imports of electricity from Norway and Sweden (international trade of electricity is studied in the section 6.5).

In figure 6.2, we illustrate aggregate generation costs together with the the major components of aggregate cost: capital costs as well as fuel and operation and maintenance costs. The capital costs are the costs after accounting for the heat credits. Each series also includes a fitted quadratic curve. The figure summarizes well the reasons for the observed changes in aggregate costs over the period. The annual fluctuations were largely driven by changes in capital costs which were primarily caused by changes in capacity factors. Note that beyond the annual variation in capital costs, there was very little long run change in capital costs. In contrast, fuel costs increased over the entire period. The increase in fuel prices was primarily responsible for the increasing trend in aggregate costs. So, the data indicate that capital costs were important determinants of annual fluctuation, but did not contribute to the long run trend of increasing costs. Fuel costs, however, contributed to annual fluctuations, but to a lesser extent compared to capital costs, but was the main factor driving the long run increase in aggregate costs.

6.3 Additional Analysis

Our aim in this section is to illustrate additional features of the cost structure of generating electricity in Denmark by analysing counterfactual exercises. First, we observed that average costs were characterised by significant annual fluctuations typically caused by changes in capacity factors. To some extent, the changes in capacity factors were responses to exogenous factors (low hydro resources in Norway and Sweden, for example). In order to smooth some of the effect of exogenous factors, we recalculate the costs for each generator under a standard-year normalisation assumption. Second, we conduct a counterfactual exercise in which we analyze an environment in which wind turbines have not been introduced into the Danish power system. The objective of the counterfactual analysis is to elicit the scale of the cost effects of introducing wind into the Danish power system.

6.3.1 Normalized Costs

The analysis of costs provided in section 6.2 revealed that there was substantial variation in annual costs. Recall that these annual fluctuations were primarily caused by changes in capacity factors. In this section, we calculate average costs per megawatt hour under a standard-year normalization assumption. In particular, we smooth costs by weighting each generator's annual production by a standard-year adjustment factor. The adjustment factor reflects the magnitude of the difference between observed annual production and average production. So, the adjustment factor smooths out some of the fluctuations in costs due to large changes in annual production.

We used a straightforward method for calculating normalized costs under a standard-year assumption. Recall that G_t denotes the aggregate amount of electricity generated in year t. We calculated the average amount of electricity generated over the 14 years we studied, which we denote by $\bar{G}$. We then computed the annual adjustment factor, denoted by δ_t, which is equal to

$$\delta_t = \frac{\bar{G}}{G_t}. \tag{6.1}$$

Next, we used the adjustment factor to scale the production of each generator:

$$\hat{g}_{it} = \delta_t g_{it}. \tag{6.2}$$

So, if the annual amount of electricity generated was less than the average amount generated, the adjustment factor is greater than one ($G_t < \bar{G}$) and each generator's production is scaled up. In contrast, if $G_t > \bar{G}$, then the adjustment factor is less than one and each generator's output is scaled down. For example, in 2003 and 2006, annual production was greater than the average annual production, so the output of each generator is scaled down, smoothing away some of the exogenous effects on capacity factors. The cost calculations are all identical to those reported in chapter 5 and in Levitt and Sørensen (2014) with the exception that the output of each generator is the smoothed output $\hat{g}_{it}$. The results are presented in figure 6.3.

The normalized costs illustrate the trend in the average cost of generating a megawatt hour of electricity as well as in the cost components. Smoothing out the large annual fluctuations in capital costs reveals very little change in capital costs between 1998 and 2011. In contrast, fuel costs together with operation and maintenance costs increased over the period. However, almost all of the rise in costs was due to increasing fuel prices. The average cost of producing a megawatt hour of electricity generally been increasing since 1998 because of increasing fuel costs. The overall conclusions of figure 6.3 parallel those of figure 6.2.

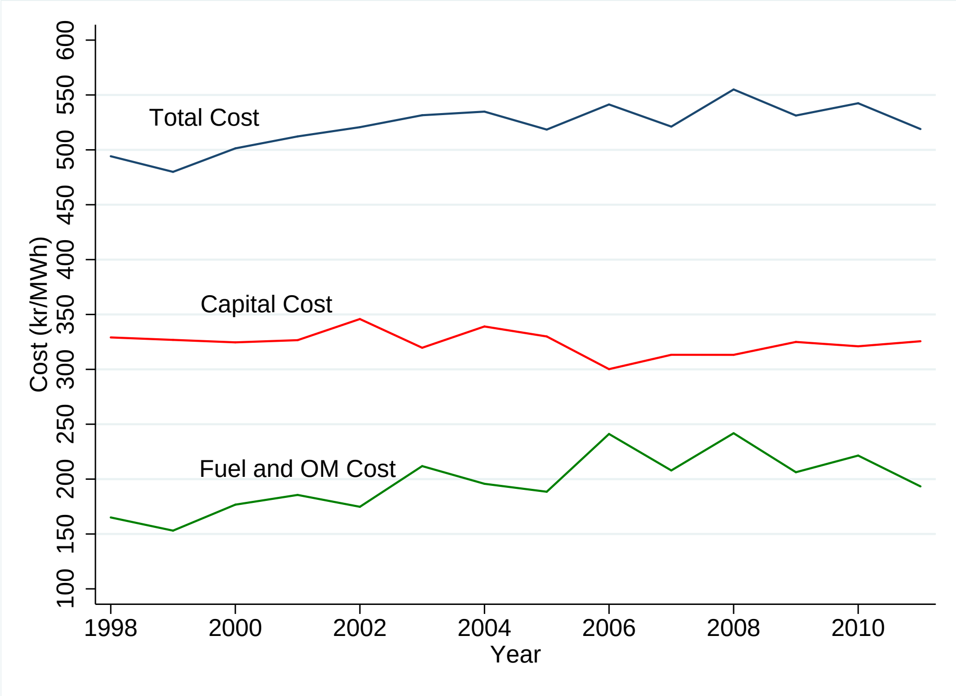


Figure 6.3: Normalized Costs, 1998-2011

6.3.2 Counterfactual Analysis - No Wind Energy

In this section, we seek to answer the counterfactual question: "What would generation costs have been in the absence of wind generation?" Of course, this is a difficult question to answer because we have to infer what the Danish power system would have looked like under a no-wind power scenario: The counterfactual is unobservable. We simplified the analysis a little by considering only the effect on generation costs and not on system-wide costs. In order to infer generation costs under this scenario, we had to make informed assumptions about electricity generation in the absence of wind power. In particular, we made various assumptions concerning the production and allocation of electricity as well as the amount of electricity traded and consumed.

We began by assuming that the electricity generated by wind turbines would have been generated by existing Danish thermal generators. In particular, electricity imports do not increase nor do exports decrease to offset the reduction in domestic electricity supply. So, the share of Danish electricity consumption served by imports does not change under the no-wind scenario. Furthermore, we assumed that the amount of electricity consumed in Denmark as well as the amount exported to Germany, Norway and Sweden does not change. The implication of this first set of assumptions is that each MWh of electricity that was generated by wind turbines must be accounted for by increasing the amount of electricity generated by thermal generators. Finally, we assumed that eliminating wind generation does not influence decisions to scrap generators. Therefore, those generators that were scrapped between 1999 and 2011 remain scrapped. These are clearly simplifying assumption. We do not allow for any market effects that may occur through changes in prices which would likely effect production and consumption decisions as well as influence international trade.

The next set of assumptions deal with the issue of allocating the electricity that was generated by wind turbines to the many different thermal generators operating in Denmark. First, it is likely that reducing the amount of electricity generated by wind turbines would affect central and public power stations more than autoproducers. Therefore, we assumed that the electricity generated by wind turbines would have been generated by central and public power stations. Second, we allocated the electricity produced by wind turbines, in each year, to each generator in public power stations, based on the relative production shares of each generator. For example, if a specific generater produced three percent of the total electricity generated by public power stations in 2002, then we allocated 3 percent of the electricity generated by wind in 2002 to this generator.

We recalculated the levelised costs of each generator and report the results in a series of panels in figure 6.4. In panel 6.4(a), we report the average annual cost of generating a MWh of electricity. The "wind power" series reports the same levelised costs reported in section 6.2, whereas the other series reports the average cost of generating a MWh of electricity in the absence of wind power. The main result is that average generation costs are lower under the no-wind scenario compared to actual costs. In particular, average annual costs are 13 percent lower under the no-wind scenario relative to the actual costs. The increase in average costs ranged between eight and 16 percent.

In panels 6.4(b) and 6.4(c), we report the effect on fuel costs and operation and maintenance cost as well as on capital costs (accounting for heat credits). As expected, fuel costs are larger in the no-wind case. Fuel costs are larger in the no-wind scenario because more coal and natural gas (as well as other fuels) must be used to generate electricity. Notice that the differences between fuel costs grew in the latter part of the period. We illustrated in previous chapters that fuel prices were increasing in the latter part of the period which accounts for the increasing wedge between the two fuel costs.

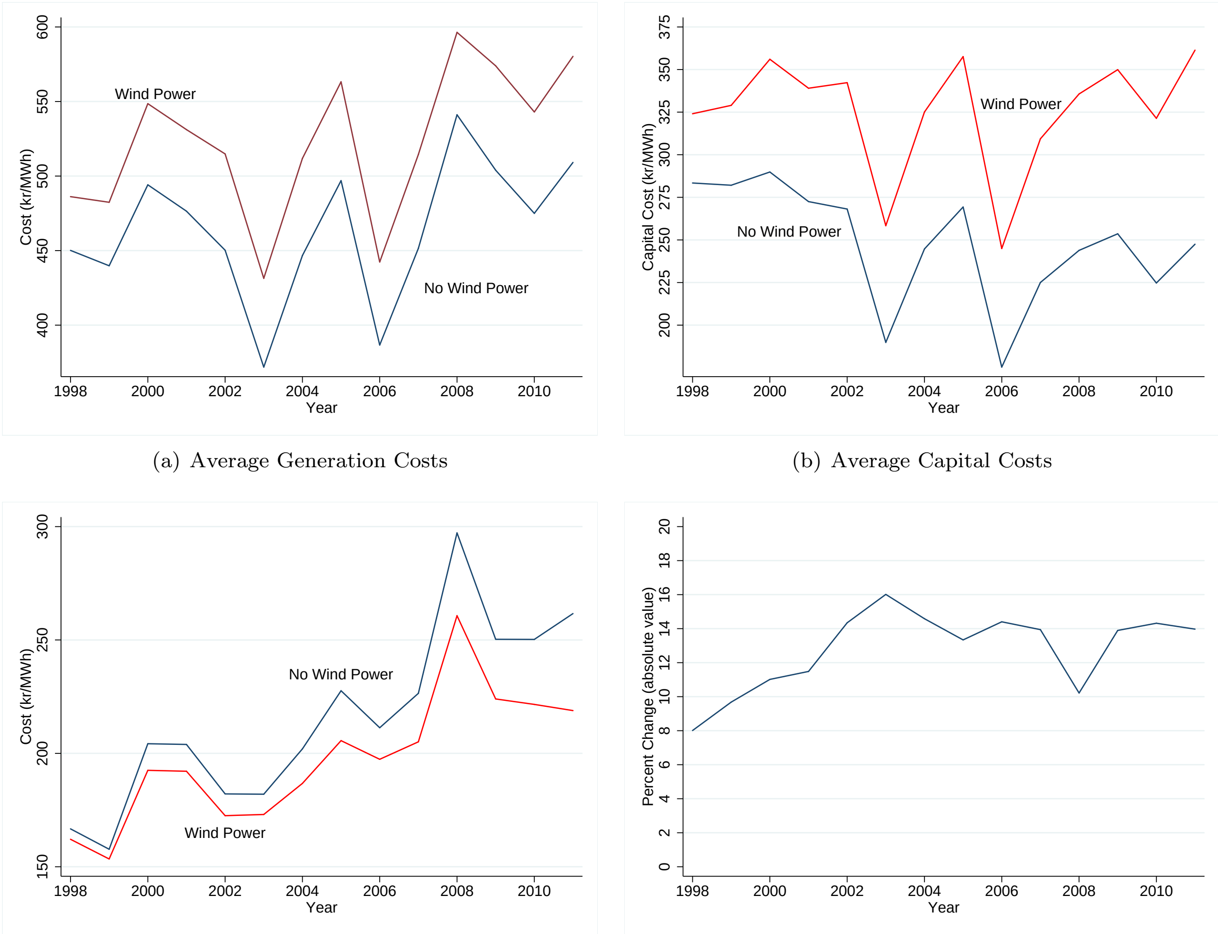
Capital costs are lower under the no-wind scenario largely due to thermal generators using more of their capacity. Larger capacity factors resulted in lower average fixed costs. The difference in capital costs increased over the period because capacity factors grew larger due to the growing amounts of wind power that needed to be replaced. The decrease in capacity costs more than offset the increase in fuel costs resulting in lower average costs. In the last panel, we report the percentage change in the average cost of generating a megawatt hour of electricity. On average, total costs decreased by 13 percent with the increase ranging between eight and 16 percent.

We conducted the same counterfactual analysis using the standard-year normalization described in section 6.3.1. The results are reported in figure 6.5. It is easier to see the trends in the smoothed cost data. Not only are capital costs lower in the no-wind scenario, but also decreased over time. In contrast, capital costs in the base case remained relatively constant. Fuel costs were higher in the no-wind scenario and followed a skewed inverted-U shape: Costs rose from 1998 to 2008, then started to decrease at least up to 2011. The wedge between the two costs grew in the later part of the period. The last panel in figure 6.5 illustrates the percentage change in the average cost of generating a megawatt hour of electricity. The decrease in costs ranged between eight and 19 percent. The largest decreases occurred in the later part of the period.

6.4 System-Wide Costs: Transmissions and Distribution

The proceeding chapters have all focused on computing the average cost of generating a megawatt of electricity by various classes of generators. Specifically, the costs calculated in section 6.2 are the levelised cost of generating electricity. Levelised costs of generating electricity do not include system-wide costs of the power system which include transmission and distribution services as well as the costs associated with ensuring a stable and secure supply of electricity. The main focus of this book is to examine the evolution of generation costs given the transformation of the Danish power system. However, a brief analysis of the costs of system-wide costs illustrates the overall scale of the costs of the Danish power system as well as emphasizing the scale of generating costs.

In this section, we provide a brief overview of the costs of operating the transmissions and distribution services as well as the costs of ensuring a stable and secure supply of electricity. The institution charged with



(a) Average Generation Costs

(b) Average Capital Costs

(c) Average Burner-Tip and OM Costs

(d) Percentage Decrease in average cost per MWh

Figure 6.4: Wind Power Versus No Wind Power, 1998–2011

running these services is typically called a Transmission Systems Operator (TSO). In Denmark, the TSO is an independent, state-owned firm called *Energinet.dk*. *Energinet.dk* was established in December 2004 by a merger between a number of Danish Power firms including *Eltra*, *Elkraft Systems*, *Elkraft Transmission*, and *Gastra*. The effective operation date was January 2005.

For the purpose of our study, we focus on two important functions of *Energinet.dk*.[1] Broadly defined, these two function are:

1. maintain system security and adequacy;
2. develop and maintain the Danish electricity transmission infrastructure.

System security refers to the ability of an electric system to withstand sudden disturbances such as unanticipated loss of system elements. Moreover, demand for power varies over the course of the day, with demand being low overnight relative to daytime hours. There is also significant hourly variation in demand. The Transmission Systems Operator (TSO) must ensure that the power supplied balances the power demand at all times or the system fails. For example, if the actual amount of wind generated power turns out to be less than the amount of wind energy expected (perhaps due to a sudden storm) then the TSO must be able to call on operating reserves in a very short period of time or the power system will fail.

[1]Because we are mainly interested in the production costs of generating and distributing electricity we do not consider some other costs of *Energinet.dk*. These include subsidies to renewable generation or expenditures on research and development. In addition, *Energinet.dk* is also tasked with running the Danish natural gas distribution system. We did our best to only include those costs directly associated with the power sector.

(a) Average Generation Costs

(b) Average Capital Costs

(c) [Average Burner-Tip and OM Costs

(d) Percentage Decrease in average cost per MWh

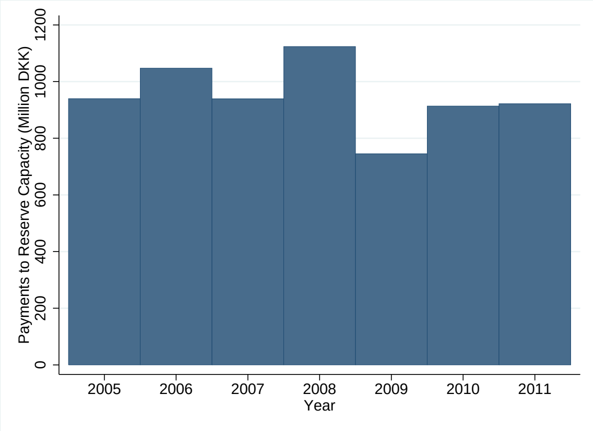
Figure 6.5: Wind Power Versus No Wind Power, 1998–2011 (Standard-Year)

In contrast, system adequacy refers to the electric system's ability to supply aggregate electrical demand of customers at all times, taking into account scheduled and expected unscheduled outages of system elements. In other words, adequacy is the property of the power system having enough capacity to remain secure almost all of the time. Maintaining system adequacy requires planning over longer horizons to ensure that adequate capacity is maintained in the system. For example, the decision to construct the Great Belt Power Link was made partly do to planned decommissioning of aging generating plants as well as in response to the general age of the stock of generators. The new transmission line linked Western and Eastern Denmark's power systems easing strains on reserve capacity by introducing more competition (Energinet.dk (2007)).

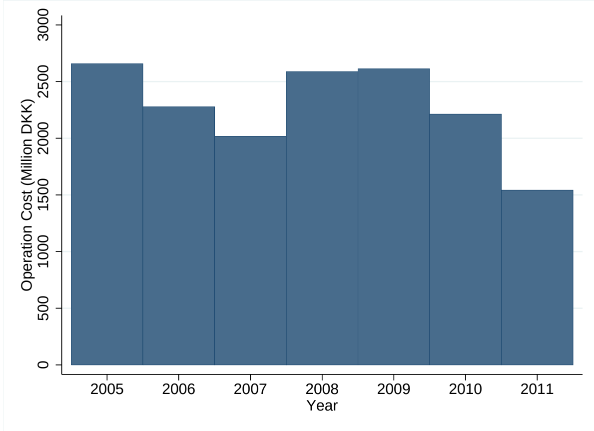
System security is pursued by the TSO by purchasing reserve capacity that can be called on to generate electricity to meet excess demand at any point in time (load can also be shed if supply is greater than demand). Total expenditure on procuring reserve capacity is illustrated in panel 6.6(a) in figure 6.6.[2] The payments to reserve capacity varied from year-to-year, but there was no discernable trend. The annual fluctuations in payments were due to changes in the price of reserve capacity. A number of different capacity markets exist. An intraday market for manual reserves exists in Denmark to facilitate the purchase of reserve capacity. In addition, Denmark is also part of the Nordic regulating market. The price of reserve capacity is determined by supply and demand forces within these markets.[3] For example, the decrease in the cost of reserve capacity

[2] All costs reported in figure 6.6 were collected from *Energinet.dk*'s annual reports. All costs are reported in real 2011 Danish Kroner.

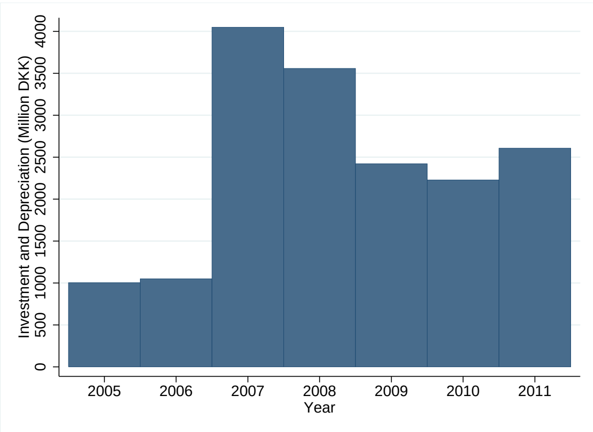
[3] For a general overview of the economics of capacity markets see Cramton et al. (2013).



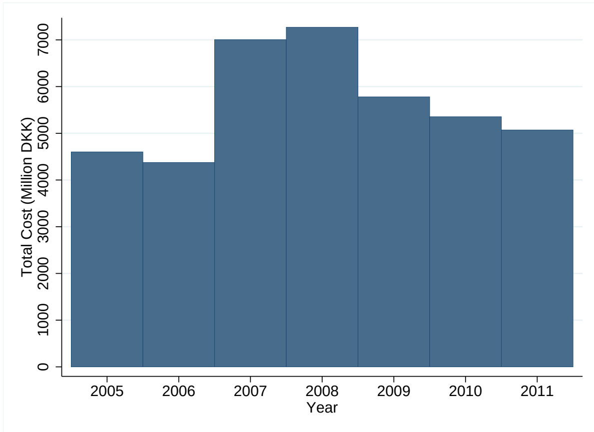
(a) Payments to Reserve Capacity



(b) Operation Costs



(c) Investment and Depreciation



(d) Total System Cost

Figure 6.6: TSO System Cost, 2005–2011 (Million DKK)

observed in 2009 was due to an increase in supply by local CHP plants. In particular, the supply of electricity in the reserve capacity market increased because the CHP plants were unable to sell their power generation due to fierce competition on the spot market. Instead, the power generated by these plants was put up for sale in the reserve capacity market (Energinet.dk (2009)). The increase in supply decreased prices in the reserve market.

Developing and maintaining transmission infrastructure refers to the everyday activities of the TSO as well as to investments in maintaining or enhancing infrastructure. We organized costs into these two categories. Operation costs were incurred by *Energinet.dk* while running and managing Denmark's transmission system. These costs include, for example, the costs associated with connections to foreign grids, labour costs and costs of accessing grids not owned by *Energinet.dk*. Note that these costs do not include the purchase of reserve capacity. Operation costs are reported in panel 6.6(b) in figure 6.6. Costs ranged from a low of $kr1,542M_{2011}$ to a high of $kr2,657M_{2011}$. The average expenditure was $kr2,272M_{2011}$.

The last class of costs are investments and depreciation. The cost of capital investments and depreciation were taken from *Energinet.dk* annual reports. We report these costs in panel 6.6(c) in figure 6.6. There was a large range in the investment costs over the period. Costs were low in 2005 and 2006 because *Energinet.dk* was newly created and not much time had passed for developing long run investment strategies or their implementation. Investment costs jumped dramatically in 2007 and 2008 because of *Energinet.dk*'s first large investment in transmission infrastructure: 2007 was the kickoff year for the Great Belt Power Link.

Total costs are reported in the last panel of figure 6.6. Note that costs are not available for the years prior to 2005 since there was no central TSO operating in Denmark. Prior to the establishment of *Energinet.dk*, there was a collection of regional system operators which made it very difficult to construct system costs. Total costs peaked in 2007 and 2008 at over $kr7,000M_{2011}$ primarily due to the construction of the Great Belt Power Link. Total costs have been declining since 2008. The largest contribution to total costs over the seven year were made by investments in infrastructure followed by operation costs. Comparing system costs to generation costs reveals that system costs are about a quarter of the costs of generating electricity.

6.5 International Trade in Electricity

The electricity generated in Denmark is both consumed domestically as well as exported for use in other countries. Moreover, the electricity that is consumed in Denmark is not generate entirely domestically. Importantly, the Danish power system is interconnected to power systems in Norway, Sweden and Germany. The transmission grid and interconnections over which electricity is delivered and exchanged are owned and operated by *Energinet.DK* (see the brief discussion of *Energinet.DK* in section 6.4). The Danish power system is split into two reginal systems: Eastern and Western Denmark. However, the power systems in eastern and western Denmark are interconnected by the Great Belt Power Link which became operational in 2010. The Great Belt Power Link has a 600 MW transmission capacity.

The power systems in the two regions are also connected to power systems in Germany, Sweden and Norway. The transmission grid in Eastern Denmark is connected to Sweden with two high voltage cables ($400Kv$ each) and two low voltage cables ($132Kv$ each). The export capacity from eastern Denmark to Sweden is approximately 1700 MW, whereas the import capacity is 1300 MW. Eastern Denmark is also connected to Germany. The transmission capacity between Germany and Eastern Denmark is 600 MW. Western Denmark is also connected to Sweden and Germany. The exporting capacity to Sweden from Western Denmark is around 740 MW, whereas the export capacity to Germany is 1700 MW. In addition to the interconnections with Sweden and Germany, Western Denmark is interconnected with Norway. The export capacity from Western Denmark to Norway is about 1500 hundred MW. Finally, there is a low voltage connection between Sweden and Bornholm which has an export capacity of only 60 MW.

The fact that Denmark is connected to power systems in Germany, Norway and Sweden means that decisions concerning how much electricity to generate are influenced not only by Danish demand, but also the demand and supply of power in the three foreign markets. The annual volume of trade between 1998 and 2011 is illustrated in figure 6.7. We also illustrate the annual amount of electricity generated in Denmark in the same figure. The aggregate amount of electricity exported to Norway, Sweden and Germany ranged from a low of 6 thousand GWh in 2001 to just over 13 thousand GWh in 2006. Annual imports had a slightly larger range: Four thousand Gwh to just over 13 thousand Gwh. In general, the amount electricity exported has increased since 1998. Although exports have been declining since their peek level in 2006, exports in the later years were still higher than pre-2002 levels. Imports of electricity also increased over the period. One interesting difference between exports and imports is that imports experienced more annual variation than exports.

Of course, there is a clear relationship between imports, exports and domestic generation. The annual fluctuations observed in domestic production are correlated with imports. Moreover, the amount of electricity generated in Denmark tended to increase when the difference between exports and inputs (net exports) was large. The spikes observed in 2003 and 2006, which were first discussed in chapters 4, occurred when there was a decline in the amount of imported electricity. In particular, the drop in imports observed in 2003 and 2006,

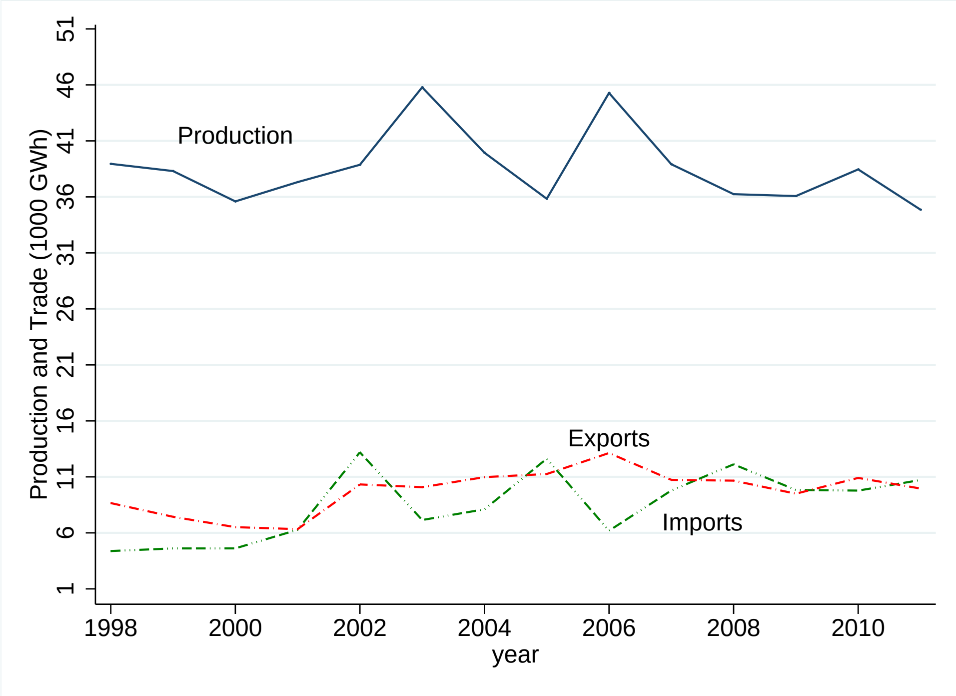


Figure 6.7: Electricity Generation, Imports and Exports, 1998-2011

was due to significant reductions in the amount of electricity coming from Norway and Sweden (see figure 6.8). The amount of electricity imported from Germany increased in these two years, but not enough to replace the decline in imports from Sweden and Norway. In response, the amount of electricity generated domestically had to increase.

Exports of Danish generated electricity is a source of revenue for domestic producers. The amount of electricity exported to Norway, Sweden and Germany is reported in figure 6.9. Germany has been the main destination for Danish exports over the 14 years, followed by Sweden and then Norway. Exports had generally increased from 1998 to 2008 with exports to Germany and Sweden increasing more than exports to Norway. This was substantial variation in annual exports to Norway and Sweden which likely reflects their dependance on hydro resources.

6.6 Consumption Measure of Costs

In this section, we calculate a measure of the consumption costs of electricity. By consumption cost we mean the cost of a megawatt hour of electricity that is consumed in Denmark. The consumption costs include both generation and system-wide costs as well as exports and imports. First, we calculate average system-wide costs, which we denote by SY_t. In particular,

$$SY_t = \frac{\text{system-wide costs}_t}{G_t} \tag{6.3}$$

where G_t is the amount of electricity generated in Denmark and the system-wide costs are those reported in section 6.4. The units of SY_t are kroner per megawatt hour. These average system-wide costs were added to the average cost of generating electricity. Next, we accounted for international trade by subtracting out exports and adding imports. In particular, we divided total expenditure on imports and total revenue from exports by aggregate domestic production. These two measure provide a proxy of the costs and revenues associated with

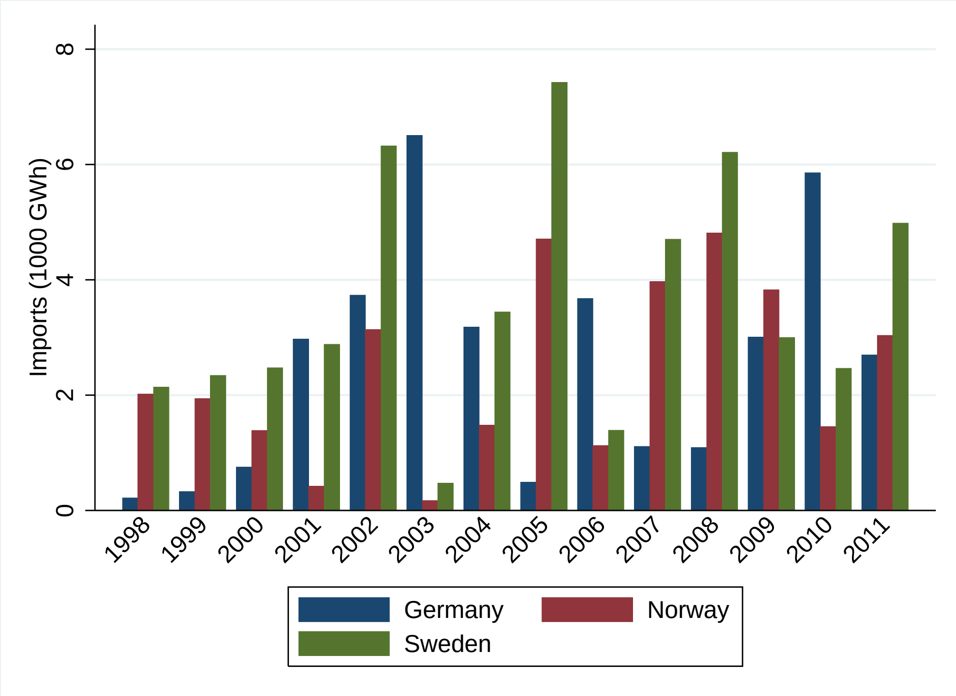


Figure 6.8: Electricity Imports, 1998-2011

trade. So, the consumption measure of costs is

$$CM_t = (C_t + SY_t) - EX_t + IM_t$$

where the units of CM_t are kroner per megawatt hour. This measure should be interpreted in conjunction with the implicit assumptions we make by computing this measure. Importantly, the underlying costs of generating electricity in Sweden, Germany, and Norway are similar to the costs of generating electricity in Denmark. More precisely, we assumed that electricity prices were equal to average costs of production to insure that revenues from exports and imports reflect costs. We are aware that this measure involves mis-measurement due to the various assumptions. Consumption costs are reported in figure 6.10.

International trade had very little influence on the production costs of the electricity consumed in Denmark. However, costs increased be between 20 and 30 percent when system-wide costs are included.

There is an additional source of revenue earned by producers burning coal and waste to generate electricity. A by-product of burning coal and waste is the residual ash and gypsum that can be used in construction industry for different purposes. In particular, the Danish technology manuals (see for example Danish Energy Agency (2012c) reports that coal fired generators produce approximately $4kg$ of ash per GJ of fuel burned in generating electricity, whereas about $2.3kg$ of gypsum per GJ of fuel is produced. Unfortunately, we were unable calculate revenues earned by producers from these secondary markets simply because we could not obtain data on prices and quantities of that were sold to the construction industry in Denmark.

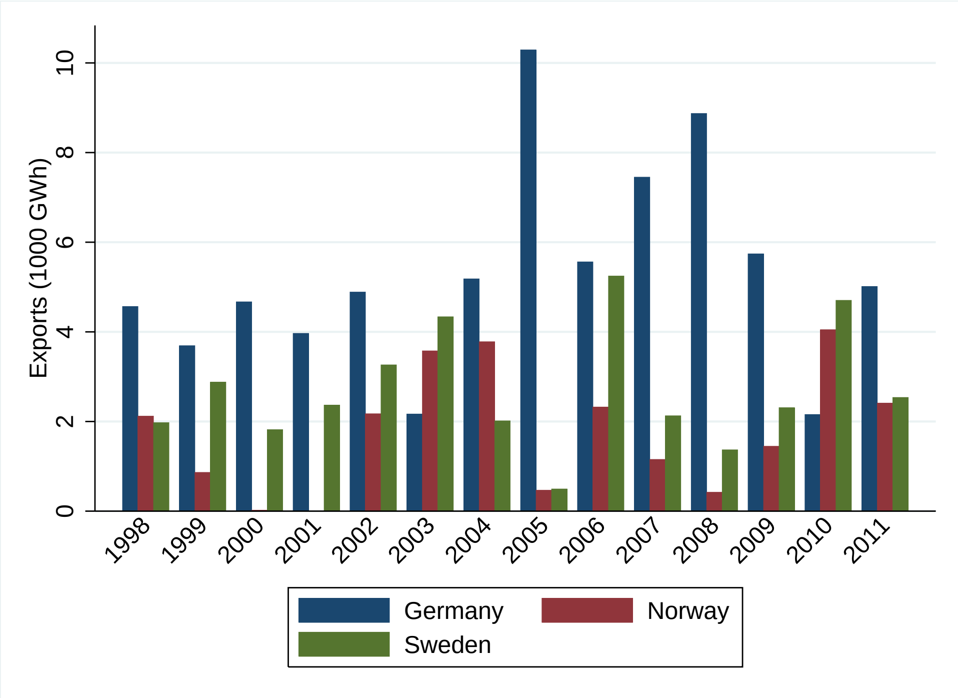


Figure 6.9: Exports, 1998-2011

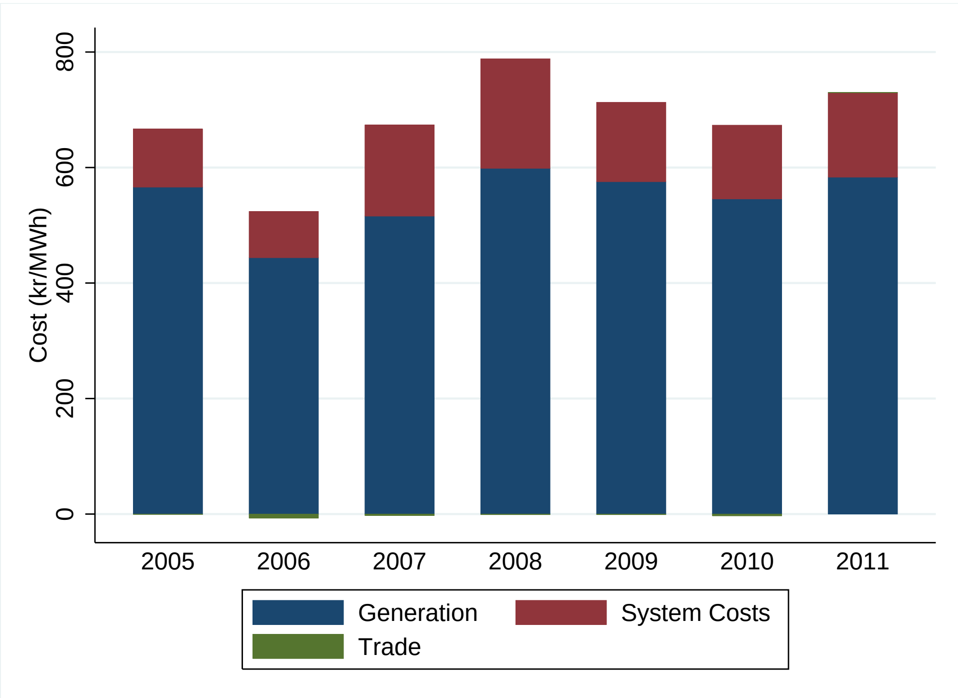


Figure 6.10: Adjusted Costs, 2005-2011

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