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Integration of 50 % wind power in a CHP-based power system

A model-based analysis of the impacts of increasing wind power and the potentials of flexible power generation

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Preface

This report has been submitted at the Department of Electrical Engineering at the Technical University of Denmark as part of the requirements to achieve the Master of Science in Energy Engineering.

The thesis is developed in collaboration with, as well as with guidance from, Ea Energianalyse A/S (Ea), and I owe many thanks to all the employees for fruitful discussions, inputs and for creating a pleasant and inspiring atmosphere to work in. A special thanks goes to my supervisor Hans Henrik Lindboe (Ea) for first introducing me to the main objective of this thesis plus continuous guidance, and to Lars Bregnbæk (Ea) for essential guidance regarding the building of the model including explanations of theoretical basics. I would also like to thank my supervisor Zhao Xu from Centre for Electric Technology at DTU, for constructive comments and guidance throughout the entire process and Liv Bjerre for help on the statistical analysis using SPSS as well as for feedback regarding the presentation of the content. I would also like to thanks Adam Bank Lentz for constructive comments. However, the full responsibility of the final design of the thesis lies with the author.

Over the last years much have been written about the integration of large wind capacities in power systems and the implications of this for future power system design, operation and control (see among others Ackermann 2005). However, the present thesis is the first to my knowledge which specifically models the impacts of large wind capacities implemented in a CHP-based energy system, and in this way examines, not only the implications of increased wind power in the Danish energy system of today and in the future, but also the effects of different potential instrument as solutions to this challenge.

Copenhagen, June 2009

Thorbjørn Vest Andersen

Abstract

By 2025, 50 per cent of the Danish power generation is to come from wind power, as a result of the commitment of the Danish government to a target of 30 per cent of energy from renewable sources by 2025. Already today, the interplay between wind power and thermal power generation creates disadvantages in the form of electrical spillover. In this thesis, the impact of wind production on price formations and production patterns are analyzed and a methodology for estimating the effects of 50 % of the wind power is presented and applied for a system similar to the energy system of West Denmark. The method is based on economic optimization using a unit commitment model, and the effect of increased wind power is estimated for three different systems: a reference system (no system changes), a system with optional bypass of high-pressure turbines on central steam units, and a system with heat pumps. Results show that wind production together with a waning electricity demand, cold nights, the hour of the day (the early morning hours), low interconnection capacities as well as a constant central production increase the probability of electrical overflow and thus; hours with critically low prices. Furthermore, result shows that the amount of electrical overflow increases along with increased wind capacity, together with the amount of hours with critically low prices. In addition, the modeled extraction units tend to down-regulate or even de-commit as the wind power increases, without compromising technical boundaries. This raises questions about the lack of down regulation from central units as observed in the real power system. Analyses of the system economy show that the increasing wind has little impact on the reference system due to inflexibility in the combined heat- and power system. However, there are positive impacts to be found when applying bypass and heat pumps, which also improves the utilization of the increasing wind capacity. As the positive impacts from heat pumps seem greater than from bypass, bypass could have large potential in relation to feasibility here-and-now, and is therefore worth dedicating further examinations. However, as both bypass and heat pumps improves the economy for central units, heat pumps are limiting the market for decentralized CHP units. It has been argued that applying these techniques to the Danish energy systems as means of creating flexible electricity production is a feasible way of coping with the challenges of the 50 % wind power scenario.

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Nomenclature

Abbreviations:

BPO:	Short for extraction units being in the state of ByPass Operation, in which heat is produced without generating electricity. Sometimes referred to just as bypass.
CHP:	Combined Heat and Power is the use of a heat engine or a power station to simultaneously generate both electricity and useful heat. CHP captures the by-product heat for domestic or industrial heating purposes - as hot water for distric heating.
CLP	Critically Low Price. A price on electricity below 6.61 € (50 Dkk) per MWh.
COP	Coefficient Of Performance. Indicates the amount of heat from heat pumps per unit electricity.
el.	Short for electricity or electrical.
Exp	Exponent
LF	Load Factor, or full-load factor.
MIP	Mixed Integer Programming
MWh	Megawatt hour
RE	Renewable Energy
TSO	Transmission System Operator. The Danish TSO is Energinet.dk.
UC	Unit Commitment

Greek letters:

β	Weight in the logistic regression.
α	Constant in the logistic regression.
η_{bp}	Heat efficiency during bypass operation
$\eta_{CHP,i}$	The CHP net efficiency of unit i (equals the heat exchanger efficiency)
$\eta_{el,i}$	Electrical net efficiency of unit i
$\eta^{CHP}{}_h$	Marginal CHP heat-efficiency

Latin letters:

$b^t{}_i$	Binary variable indicating whether to switch BPO on or off (0;1)
C	Stochastic objective function

$C_i(e,h)$	Cost function
$c_{v,i}$	Loss of electricity per unit heat extracted from the turbine buckets of unit I (ISO-fuel value)
$c_{m,i}$	Backpressure value of unit i
M	A very large number
mc_i	Marginal costs of unit i
mc_{cp}	Marginal costs of central boilers
mc_{cbp}	Marginal costs of central backpressure units
mc_{dcb}	Marginal costs of decentralized boilers
mc_x	Marginal costs of hydro power (the fixed value of hydro power)
$O\&M$	Operation and Maintenance (used in connection with variable O&M costs)
P	Probability
$P^t_{cb,i}$	Boiler capacity of the central areas of unit i
$P^t_{chp,i}$	Backpressure CHP unit in the central area of unit i
P^t_{dcb}	Decentralized boiler production
P^t_{dch}	Boiler capacity of the decentralized areas
$P^t_{D,x}$	Demand in exchange area
$P^t_{D,el}$	Electricity demand in main area
$P^t_{D,h,dc}$	Heat demand in decentralized area
$P^t_{D,h,i}$	Heat demand in central area i
$P^t_{el,i}$	Electricity production from the 11 units
$P^t_{el\_bp,i}$	Electricity production from backpressure of unit i
$P^t_{el\_hp,i}$	Electricity consumption of heat pumps of central area i
$P^t_{h,i}$	Heat production of unit i
$P^t_{h\_bp,i}$	Heat production from decentralized backpressure unit i
$P^t_{h,max,i}$	Maximum heat production of unit i
P^t_i	Fuel constraint of unit i
$P_{max,i}$	Maximum power generation on central unit i
$P_{min,i}$	Minimum power generation on central unit i
$P_{st,i}$	Maximum starting power of unit i
P^t_W	Production from wind
$P^t_{W,max}$	Maximum production from wind
P^t_x	Power generation from exchange area
P^t_{12}	Exchanged power

$P^t_{12,max}$	Maximum capacity on external connection
$P_i(e,h)$	Power generation as a function of electricity and heat
sc^t_i	Start-up costs of unit *i*
st^t_i	Start-up indicator of unit *i*
UR	Up-ramp constraint during constant operation
x^t_i	Binary variable (0;1) indicating whether the unit *i* is committed or not
Y	Dependent variable

Chapter 1.
Introduction

1.1. Background

1.1.1. A visionary Danish energy policy

In 2007 the Danish Energy Authorities published “A Visionary Danish Energy Policy” with the vision that: Denmark in the long term is to be completely independent of fossil fuels. As a way of achieving this vision, the Danish Government has committed to a target saying that, by 2025, the amount of renewable energy must be doubled to at least 30 %, that the total energy consumption cannot increase, and finally that the use of fossil fuels must be reduced by at least 15 % (Danish Energy Authorities 2007). A great part of this vision will concern the existing power and heat system. In this connection, it has been assessed that wind power in the Danish power system by 2025 must constitute 50 % of the power generation (Ea Energianalyse 2007) – a strategy which contains great challenges for the energy system as we know it today.

1.1.2. Issues to examine in order to meet the visionary Danish energy policy

Today, the Danish energy system is unique, combining a large share of wind power with a large share of district heating. A system, which historically is a result of the seventies’ energy crisis (Den Store Danske 2009) that later on led to a development of the production, going from power being generated entirely on a few, central units, till being partially generated on hundreds of small decentralized units in the form of co-generated heat and electricity, as we know it today. As a supplement, the Danish power system today has a 20 % share of wind power, sometimes resulting in full coverage of internal consumption from wind power alone. Due to past achievements, this still provides Demark a leading position within the EU, although countries like Germany, Spain and England are strongly following up (Nielsen 2009).

Already today, the interplay between wind power and thermal power generation is experiencing some difficulties. A pre-study conducted for this project has shown that in some periods of the year, the production from wind power increases to a degree that (under the given transmission and export conditions) causes a formation of critically low electricity prices on the spot market – prices that are close to zero (Andersen 2008). And in some cases, the electrical oversupply from wind is so critical that an immediate down regulation of wind turbines is required – something often referred to as *critical electrical spillover*.

Until now, the problem of critically low prices might not be prevalent enough to economically impose changes to the Danish energy system. However, it is uncertain how large the problem will become when increasing the wind production share to 50 %. Further analyses are therefore needed in order to gain insight into the potential impacts on price formations, production patterns, system economy and environmental issues.

A high wind production is not always exclusively the factor causing critically low prices. Factors such as heat demand, hour of the day, varying transmission capacities etc. can play a part as well. In order to better understand which significant factors affect the probability of the formation of critically low prices, a further statistical study will be necessary.

A rather price-inelastic consumption of heat and electricity imposes a great challenge to a successful integration of large amounts of fluctuating wind power in the Danish energy system. Aside from power storage (which currently is at a relatively immature technological stage), there are three basic solutions to this challenge. One is to improve the external transmission. The second is to promote a more flexible and elastic consumption. A third solution is to reduce the amount of constrained power generation from CHP units via a more flexible *production*. When discussing short term feasibility, heat pumps seem as an obvious technology (Energinet.dk 2009) that can both increase the electricity consumption as well as replace CHP production. Another potential instrument (currently being at a more theoretical stage) is called *turbine bypass*. The concept of turbine bypass is to lead the steam around the high-pressure turbine on central power plants with CHP, and use it directly for heat production, thus transforming the plant into a heat producer. However, the potential of these instruments is still unknown, and need to be analyzed.

In a liberalized electricity market like the Danish almost every choice is based on economic considerations, and various economic and technical aspects have to be paid attention to before introducing drastic changes to the energy system. Since “A Visionary Danish Energy Policy” (2007) many potential solutions for an optimal integration of 50 % wind power have been suggested. However, the economic consequences of increased wind capacity are to some extend still unknown. A mathematical optimization model is therefore needed for gaining the necessary insight into the economic impacts of the increased wind power, as well as the potential effects of applying instruments for a more flexible production and consumption of heat and electricity.

1.2. Objectives

Based on the described future challenges entailed by the integration of 50 % wind power in the Danish energy system, as well as the potential solutions to resist these, this project aims at fulfilling the following three main objectives, of which the latter is considered the primary objective.

1. Identification of the main characteristics of the West Danish power- and heat system including a statistical analysis of the factors causing critically low prices with focus on the effect of wind power.
2. The development of a mathematical model of an energy system with characteristics similar to the West Danish heat and power system for optimization of the total system costs.

3. Application of the model developed in (2) to analyze the consequences of the future wind capacity, plus an analysis of the potentials of different instruments for advancement of a more flexible interplay between heat and power.

The scope of (1) is to study the characteristics of the heat- and power system for a deeper insight in relation to the elements, restrictions and physical limitations that constitute the system's properties and behavior. The statistical analysis will be concentrated around load patterns in relation to oversupply causing critically low prices. More specifically, fulfilling the first objective will imply:

A review of the West Danish transmission system and transmission capacities, plus a review of the Nordic power market.

An overview of the technical and economic characteristics of the most important generation technologies including emerging instruments and technologies for an advanced flexibility in heat and power production.

A statistical analysis of the current wind penetrations impact on load patterns and price formations, using real market data on an hourly basis.

The overall purpose of (1) is to build a sufficient knowledge base of the energy system characteristics for later use in the formulation of the mathematical model, as well as for the analyses of the modeled results in relation to the West Danish (and Nordic) energy system.

The objective of the modeling part (2) is to find an optimal, yet simplified way of approximating the main characteristics of the West Danish energy system, *on an hourly basis*, in order to build a model which reasonably can be said to produce results that projects the real system. The model is limited to correspond to the West Danish energy system (West-DK), partly since West-DK already today have a larger penetration from wind than the East Danish system, and finally because West-DK is likely to have the largest penetration in the future as well. In this connection, the knowledge gained in part 1 will be of great use in connection with the simplifications incorporated in the model.

When applying the model made under (2) for calculating the impacts of the 50 % wind power scenario in 2025 as stated in (3), there will be modeled an additional 2008 scenario for comparison with the current state of the system, as well as a "halfway scenario" representing an increase of wind capacity half as large as the one in the rather extreme 2025 scenario, in order to apply some sensitivity to the results. The instruments for an increased flexibility have in this project been limited to heat pumps and turbine bypass.

1.3. Method and Delimitation

In this section, the methods used for the fulfillment of the objectives, as well as the necessary delimitations in order to do so, is accounted for.

The present thesis is basically divided into two parts. While the first is an overall study of the different aspects of the Danish energy system, the second is the modeling part with the aim of building the model and analyzing the economic consequences of the 50 % wind power scenario. Therefore, the first part will, by building a sufficient base of knowledge, help develop a model with the exact properties needed in order to meet the primary objective. Both parts of the project imply a preceding literature study. The review of the West Danish energy system in the project's first part is a continuation of the literature study started at the pre-study. The strategy of the literature study was to select and analyze previous studies done on wind penetration in CHP based power systems, and the selection has taken place so that research papers regarding the problems connected to large wind penetration levels in a CHP based power system – especially seen from a power balancing and system responsibility aspect - have been chosen.

The focus of the review is on the elements of relevance to the model as well as the analyses of the modeled results. The analyzed data have primarily been provided by Energinet.dk covering the electrical side with parameters such as time and date, electricity prices, production and consumption, export etc, all on an hourly basis. The additional heat data has been provided by Ea. The period of time of the used data spans over five years, going from the beginning of 2004 till the end of 2008. It consists of a large number of observation points which will lay a good foundation for the statistical analyses.

The statistical analysis on the causes of critically low prices is carried out for a range of explanatory factors including the ones just mentioned in relation to analyzed data. The explanatory factors are selected on the basis of the knowledge gained from the literature study, and the statistical analyses are carried out by analysis of contingencies tables, graphs and by logistic regression. A regular spreadsheet tool (Excel) will be used for the data processing and calculations of the contingencies tables and the graphs, and for the statistical analysis of the different parameter's significant influence on critically low prices, the statistical tool SPSS will be used.

The overall purpose of the modeling part of this project (concerning point 2 and 3 of the stated objectives) is to formulate a mathematical optimization model that incorporates a number of the basic system-properties characterizing the West Danish heat and power system. The building of the model is therefore based on the knowledge obtained from the literature study as well as on a practical 'learn by doing' approach. Furthermore, it is based on a study of the materials related to the programming language of the applied modeling tool GAMS. As mentioned above, the objective is not to model a detailed approximation of this system, but to achieve a number of results that are usable in a Danish context. However, a number of input parameters, including consumption and wind profiles, transmission and production capacities, to name a few, is taken directly from the real energy system. The modeling of the power units representing the production of the system has been simplified compared to the real system. The simplifications are made in order to obtain a functioning, yet applicable model. The production will generally consist of power generation, combined heat and electricity production (CHP), and finally heat producers. The thermal units will only include the fuels: Steam coal and Natural gas. In this way, production from bio fuels and waste incineration will not be included as in the real system, which may affect the environmental outcomes. The application of turbine bypass to central steam units in the model will, be assumed feasible on all central units with heat extraction, by which only the economic feasibility will be discussed. Regarding the technical properties of the different power plants, there will in the case of bypass be a very limited discussion on the technical potentials or feasibility in relation to current Danish power units.

The heat supply will be divided into a number of central heat distribution areas partly similar in the real system, whereas – for simplifications – the many decentralized district-heating areas will be represented by one, large area. On the electrical side, the internal transmission of the power system will be merged as one bus, except from external transmission areas. This means that transmission losses and internal overstresses will be disregarded. And in some cases the results may reflect a stronger network than in reality. This is normal for a market model.

For market simplifications, the hourly supply of heat and power is limited to one hour, assuming that all energy is traded by hourly bids (cf. section 3.2). In this way, the supplies will not be restricted by any forms of block bids or long term contracts. As a result, the modeled system may reflect a more efficient spot market than the real one. The power and heat demands will be regarded inelastic. In this connection, one of the model's greatest deviations from the real heat system will be the lack of heat accumulation tanks in the model. This means that, not only power, but also the heat supply will have to momentarily balance the demand each hour, which may result in a less flexible CHP production than in the real system. Another simplification regarding the market is that the external area only produces hydro power. The basic idea of this is to imitate the interplay of power exchange between the Danish wind generation and the Nordic hydro generation, by which an exchange area like the Germany power system is disregarded.

Despite of the future aspects of the project there will be a total maintenance of values. This means, that there will not be applied any projections on growth in consumption level, fuel and CO2 prices, to the modeled system. Also, there will be no power system modifications other than the variation of wind penetration, turbine bypass and heat pumps. Although the results of this (assuming no changes) may be quite uncertain in terms of modeling a *realistic* future scenario, the fundamental idea behind doing so is to disregarding any impacts of for example fuel price variations, and thus isolating the specific impacts from the applied changes given by extended wind capacities, bypass on central power plants and inclusion of heat pump capacity.

Further descriptions of methods and assumptions are found within the report.

1.4. Applied concepts

The concept *critically low prices* have already been mentioned a couple of times in the introduction, and will be heavily used throughout the thesis. When talking about a critically low price, or sometimes, *hours* with critically low prices, a price on electricity below 6.61 € (50 Dkk) per MWh is referred to. The definition of a critically low price is determined on the basis of the price being clearly exceeded by the variable electricity generation costs of central power plants (coal). The concept is defined by the author, in order to articulate the (non-constructive) power generation, and is not a commonly used concept.

Another concept used throughout the thesis is the term *energy system*. Although the concept normally is used to describe the total primary energy consumption (including e.g. transport), it is here reduced to including only the power system plus the district heating systems.

The term *wind penetration* must be understood as the consumption of the system divided by the wind capacity. The term is used as synonym with *wind capacity*, and both terms are most of the time used in relation with *increase* in the amount of power generation from wind turbines (increased wind penetration/wind capacity).

Several other concepts are used synonymously throughout the thesis. *Constrained power*, *constrained electricity, heat-constrained electricity* and *forced electricity* are all used synonymously and are used to describe the generation of power that are constrained by the corresponding heat demand. The same applies to *constrained heat* and *forced heat* which also are used as synonyms.

As mentioned above, the results of the model are calculated for three different scenarios – a 2008, a 2017 and a 2025 scenario, respectively. These three scenarios are sometimes referred to as just *scenarios,* as *system scenarios* and sometimes as even *systems*. When used in the thesis, it will clearly appear from the context which scenario/system there is referred to.

1.5. Outline of the thesis

The following Chapter 2 is dedicated the results of the pre-project, initiating the objective of the thesis. In Chapter 3 the Danish energy system is examined, including the organization of the power transmission system, the planned system changes of the energy market, the power generation technologies constituting the Danish heat and power system of today, and the emerging technologies for increased flexibility in the interplay between heat and electricity production. Then, in Chapter 4 the effect of wind power on today's energy system is analyzed as well as the factors causing electrical spillover. However, one of the primary objectives is the effect of wind power when *increasing* the wind capacity in the energy system, and in Chapter 5, we turn towards the mathematical model doing this. The model used for estimation of the future energy system is the unit commitment model, and in this chapter, the assumptions and consideration underlying the model as well as the mathematical formulation of the unit commitment model is reviewed. In Chapter 6, the results of the estimated scenarios regarding energy prices and production patterns are presented, and in Chapter 7 the economic results of the model as well as the results on green accounting are presented. In chapter 8, the results as well as the analysis and the methods are discussed. Here, the results will be followed up by an overview of the challenges of 50 % wind power and on proposals on where to focus in connection with improved integration of wind in relation to the 50 % wind power. Finally in chapter 9, the conclusion will be drawn, and put into perspective.

Chapter 2.
Pre-study Results

2.1. The objective of the pre-study

In order to get an insight into the field, as well as to the extent of electricity production at critically low price, and thus an insight to which issues and focuses would be relevant to pursue in the present Master Thesis, a pre-study was made. The pre-study was done as a self-study course (five ECTS credit) under guidance from my supervisor Zhao Xu and Hans Henrik Linboe. There were two main objectives of the study: 1) to get an insight to the field, and to 2) to analyze the general production patterns of the Danish power system (mainly the western part) along with the price development, in order to determine to what extend electricity generation from thermal units (in central and decentralized areas) takes place at electricity prices that are lower than the production costs of the electricity. Or more specifically: to what extend power is generated when spot prices in the given hours are much lower than the marginal power generation costs (primarily fuel costs) of the specific units.

2.2. Results of the pre-study

Regarding objective 1) to get an insight to the field, a literature study was accomplished. The knowledge obtained from this will not be presented in this section, but underlies the whole thesis. However, it emerges most strongly in Chapter 3 on the structure of the Danish energy system.

When it comes to objective 2), the key assumption was made, that if units could generate power at a much lower price than the (estimated) production costs, the difference would have to be covered another way. However, it was never determined whether the loss was covered by co-generated heat or TSO-financed ancillary services[1]. Nevertheless, the assumption was that the generated amount of electricity produced at low prices was an indicator of an economically inoptimal way to supply the demand.

The year used for statistical observations was 2007, a year that in a historic frame was characterized by strongly increasing prices on steam coal plus a sufficient supply level of water in the Northern reservoirs, lowering the prices a great amount of the time.

One of the findings in the pre-study was that the amount of critically low prices was around 400 hours or 4.5 % the given year. Furthermore, the economic loss of this was

[1] For elaboration on ancillary services see section 3.2.4.

roughly estimated[2] to concern no more than around 0.5 % of the total turnovers of the electricity market, but one could argue, that this share is not high enough to be considered really problematic. Of greater importance, it was found, that when looking at the hours of critically low price, the wind power had a significant share of just 45 % of the total production in the west Danish price area (see Figure 2.1 below). Additionally, as it is seen in Figure 2.1, the share of the electricity production by decentralized and central units was 14 % and 41%, respectively, which means that thermal production constitute more than half of the power generation on an average basis.

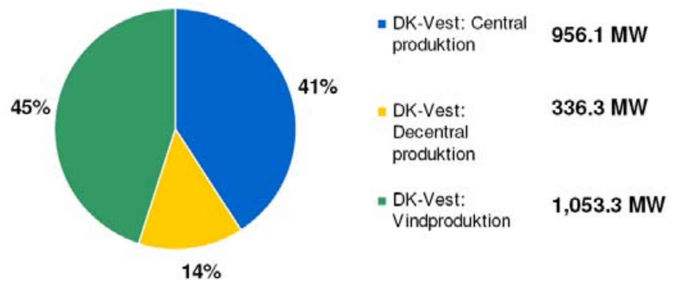


Figure 2.1, Power generation by decentralized units, central units and wind units, (data source: Energinet.dk 2007)

It was concluded in the pre-study, that the significant amount thermal power generation – observed within these hours of critically low prices – would have to be 'forced' by other factors than the electricity demand, and this led to the following thought: Why discuss the future needs for storage technologies and increased capacities on connections toward neighbor systems, when a part of the solution could be stop producing electricity when not needed?

However, the answer is not as simple as the question, and before answering, an analysis of not only the generation of electricity, but also of the generation on heat, as well as an analysis of the consequences of carrying out the plans[3] for doubling the wind power penetration of the system under these mechanisms was needed.

Since data used for the pre-study was purchased from the Danish Transmission System Operator, Energinet.dk, it only covered the electrical side, leaving out information on the heat production in particular, which just stressed the need for an analysis of how a system like the Danish, which is based on a relatively complex interplay between heat and electricity production, would react to such an increasment of wind power.

[2] Calculations were based on an assumed heat price.

[3] A visionary Danish Energy Policy (Danish Energy Authority 2007).

Chapter 3.
Characteristics of the Danish energy system

3.1. An Insight to the Danish energy system

In order to fully understand the assumptions and choices made later on when modelling the mathematical model, an insight into the Danish energy system[4] is necessary. Therefore this chapter is dedicated a review of the Danish Energy System. Focus will be on both the electrical and the district-heat part of the system, since the future increase in wind penetration will be considered a problem, not only to the power system, but to the energy system as a whole, presumably.

At first I will account for the Danish energy system with emphasis on the organization of the power transmission system, the planned changes of the system from now up until 2025 and the composition of the electricity market. Afterwards, the different power generation technologies that constitute the Danish heat and power system today will be explained, among these: extraction and condensing units, back pressure units and wind turbines, and finally I will go over some of the potential instruments for increased flexibility in the electricity production – including heat pumps, electrical cartridges, turbine bypass, boilers, capacity extension and energy storage technologies.

3.2. Energy system characteristics

3.2.1. The Danish power transmission system

As seen in Figure 3.1, the Danish power transmission system is split into a western and an eastern transmission area, with a common transmission system operator (TSO) responsible: Energinet.dk. The most significant feature of the transmission system is the way in which it is connected. The eastern part, Sealand, is synchronously connected to the Nordic power system area called Nordel, while the western part is synchronous connected to the European system through the mainland connection to the south. From the western part 1000 MW of DC sea cables are connected to Norway and 740 MW to Sweden, respectively. Conversely, the Eastern transmission system is connected to the Kontex area through Germany via of a 1700 MW DC connection. A 600 MW DC cable, con-

[4] Although the term energy system normally is used to describe the total primary energy consumption of Denmark, the term is in this connection reduced to including only the electrical part of the system plus the district heating.

necting the two non-synchronously Danish systems, is presently under construction and is expected to be commissioned in 2010. Furthermore, plans are to establish a third connection to Norway within a few years, in order to meet the increasing need for exportation (Energinet.dk 2007).

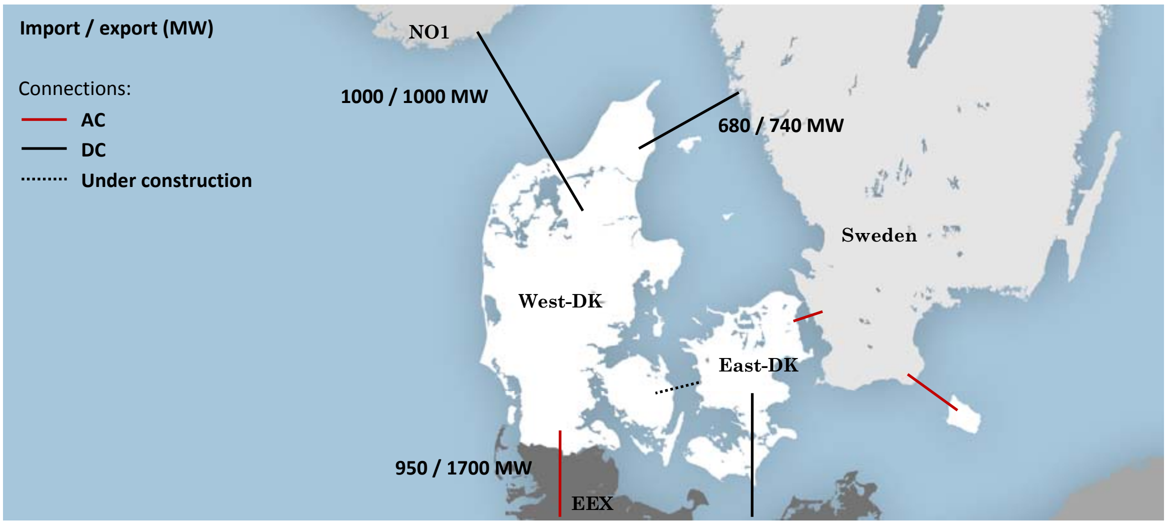


Figure 3.1. Overview of the connection capacities between the two Danish Transmission systems and the surrounding countries (data source: Energinet.dk).

In the Nordic area, the different TSO companies have assembled in a corporation called Nordel in order to achieve a uniform Nordic system operation. The first step in this process is to make the transmission between the Nordic countries more efficient. Unfortunately, the effectiveness of the collaboration with the German TSO has still not reached the Nordic level (Energinet.dk 2007). A symptom of this is seen from the different capacities on the connection between West-DK and Germany (Energinet.dk 2006). In addition, the Swedish TSO Kraftnett, has occasionally been accused of exploiting the frequent bottleneck situation between the north and the south of Sweden (Hvidsten 2006) and hence, manipulating the internal Swedish market price.

The state owned Danish TSO Company Energinet.dk has the overall responsibility for the development and maintenance of the transmission network, as well as for the momentary active and reactive power balancing. Additionally Energinet.dk is in charge of the primary and secondary frequency control, although other balance-responsible parties (BRPs) often are handling this in practice. The TSO Company's role can be described with the fallowing two keywords: system security and system adequacy (Ea Energianalyse 2007). Security covers the adjustment of rapid and unexpected changes in production and demand of active and reactive power, and adequacy covers the securing of sufficient generation capacity for the more rare cases of energy shortage. To be able to fulfill these main responsibilities the TSOs, among these Energinet.dk, have a set of fundamental tools at their disposal – one of these being *ancillary services*.

One of the ancillary services purchased by Energinet.dk for immediate balancing is the commitment of at least three central power plants for each transmission system, which controls speed and grid voltage. A service made possible through contracting with companies able to deliver this service (Ørum 2008). For balancing on a lower time scale the

TSOs also have the opportunity of activating reserves manually – reserves that also goes under the name of balancing power, which is an ancillary service that the Nordic TSO companies can purchase via an electricity stock market. In this way TSOs have been significant players on the market, purchasing ancillary services such as balancing power, since the liberation of the electricity market[5].

When it comes to the insurance of system adequacy, one of the tools at the TSOs disposal is to expand the transmission capacity of the interconnections (especially since the role of establishing power plant-capacity today belongs to the market). The foreign connections have traditionally been of great use to Energinet.dk. The great advantage is, that the Nordic water reservoirs in principle functions as energy storage when overproduction of wind power occurs in West-DK and North-Germany. The disadvantage, on the other hand, is the pressure these situations sometimes cause on the internal grid when much energy is transmitted over long distances (Energinet.dk 2007). To cope with this problem Energinet.dk has lately been focusing more and more on raising the amount of price-elastic power consumption over the recent years (Energinet.dk 2006, 2007) by, among other things, suggesting that intelligent recharging of electric cars could be a key factor in this connection (Energinet.dk 2009).

3.2.2. District heating

A significant quality of the Danish energy system is the large scale distribution of district heating covering around 60 percent of the heat demand (Energistyrelsen). The combined heat and power generating is characterized by 1) electricity being a homogeneous good[6] where both consumers and suppliers connect to the same extraction point of the entire power grid (ideally) and 2) heat distributed in a *local* network by a single, or a few, heat suppliers. In larger cities however, more heat companies are feeding the same network. In Copenhagen for example, CHP (combined heat and power) areas lie side by side (as seen on Figure 3.2), which has recently resulted in plans on establishing a market situation quite similar to the electricity market (Varmeplan hovedstaden 2008). In relation to the electricity market, small, decentralized CHP units are normally paid by the produced MWh of power through a three-step tariff-agreement (almost like in planned economy). This means that this part of the power generation often is naturally constrained by the heat demand (Ackermann 2005).

[5] All Nordic countries have liberalised their electricity markets, opening both electricity trading and electricity production to competition. Norway was the first Nordic country to launch the liberalisation process of its electricity market with the approval of the Energy Act in 1990. Norway was followed by Sweden and Finland in the middle of the 1990s and by Denmark at the beginning of 1998 when the large electricity customers were given access to the electricity network (NordREG, *The Development on the Nordic Electricity Market*).

[6] Different generation technologies each produce the heterogeneous good: electricity, which, when added to the grid, transforms into a homogeneous good. (Kogelschatz 2004). In reality, currents have the property of going ways with lowest resistance, often meaning traveling the shortest distance.

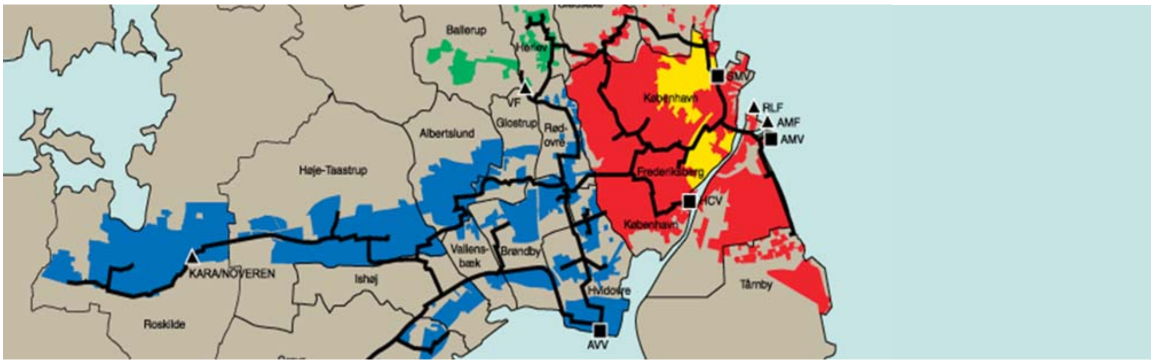


Figure 3.2, Picture of a larger branched heat-system in Copenhagen that includes a number of heat producers (Source: Varmeplan Hovedestaden)

3.2.3. System planning – now, and until 2025

As mentioned earlier Government plans are to increase the level of renewable energy in the system within 2025 to 30 %. It has been derived that an increase of the current wind penetration level from approximately 25 pct. to 50 pct. is among the necessary means for reaching the goal within the stated time frame (Energinet.dk 2007). In their system planning report from 2007 Energinet.dk suggest that the expansion of wind capacity in West-DK will take place as shown in Table 3.1. The table shows a huge relative increase in offshore capacity where land mills are expected to gain 1000 MW and offshore is expected to gain approximately 2000 MW.

Area / capacities [MW]	2008 Capacities	2025 Capacities	Increase
Land mills (on-shore)	2232	3232	+ 1000
Offshore:			
Horns Rev	160	1160	+ 1000 (5 x 200)
Jammerbugten	-	600	+ 600 (3 x 200)
Anholt	-	400	+ 400 (2 x 200)
Total capacity	2392	5392	+ 3000

Table 3.1, Suggested strategy for wind capacity increasment made by Danish TSO in order to meet political goals (data source: Energinet.dk 2007).

As the TSO being the company in charge of the planning and construction of the future transmission system, the TSO suggested means for coping with the challenges related to the doubling of the wind capacity are considered the most likely to happen, and I take these into account when modeling later on. The TSO suggested initiatives are stated below. First, the potential initiatives on the el. generation side:

1. Production regulation of Wind turbines
2. Geographical spread of turbines
3. More focus on mobilization of reserves, regulation resources and new types of facilities.

The first initiative implies a need for controlling the power output of the wind turbines. Today, this is only regulatory standard when grid-connecting larger wind farms (Ackermann 2005). The second initiative refers to the fact that it is possible to even out the stronger fluctuations by spreading out the units, since a large concentration of turbines causes larger fluctuations. And the third initiative points at the increasing need for capacity with better and faster regulatory properties, such as typical peak load units (Energinet.dk 2007). The following steps regarding the transmission are recommended:

1. Move grid connections for offshore wind farms.
2. Increase transmission capacity in the grid by means of high temperature conductors.
3. Strengthening and expansion of the existing grid.

All three steps are based on the premise that large wind farms, due to load flow considerations, often stresses the local grid. As a consequence they ought to have their connection point placed in a "stronger" part of the transmission grid to avoid overloading the often weaker connections existing close to the shore.

Finally, and this is where the greatest changes are to be found, the initiatives regarding the consumption side are:

1. Connection of electricity to the heat side, primarily through heat pumps and el. cartridges.
2. Electric cars as price flexible consumers.
3. Additional price elastic consumption.
4. Electric energy storage.

While initiatives 2, 3 and 4, when it comes to feasibility within *near* future, more likely seems to belong in a future scenario, the initiatives of step one is expected to play a much more significant role in the future system, and is therefore included as part of the framework of the project.

3.2.4. Market composition

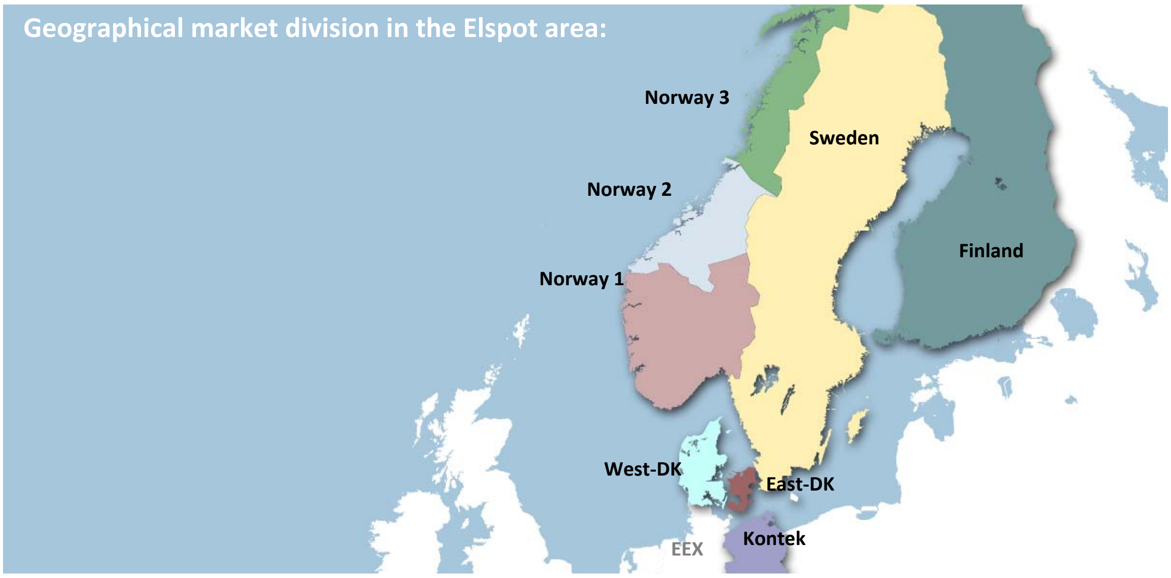


Figure 3.3. A geographical overview of the markets in the El Spot-area. Note that Sweden and Finland have not being internally divided into markets like the rest, and that the Kontek area represents the former East Germany, while the remaining German system goes under EEX. (Source: Nordpool Spot)

The Spot market

The Spot market is the place where producers and buyers trade physical power. The primary function of an organized spot market for electricity is to maximize cost efficiency by ensuring that the most economic supplier get to satisfy the demand for power (Nord Pool Spot)

Ever since the Danish power systems and its parties fully switched to market conditions, all trading activities in the Nordic area have been taking place at the physical spot market: Elspot – owned and managed by the company Nordpool Spot. Here, power is traded one day ahead on an hourly basis every day. Other goods such as CO2 certificates are traded on Nordpool as well. Entrants on Elspot are primarily producers, heavy industrial consumers buying for themselves and finally; retailers – reselling the energy to “regular” consumers such as households.

Today, Elspot prices are formed in eight different price areas allocated on five countries[7]. Although the power is traded on an hourly basis, not all energy on Elspot is traded via the hourly bid. Some quantities are offered for much longer time periods, in fact, some bids are independent of price for all hours. Also, a part of the suppliers make use of block bidding while setting a sort of 'all or nothing' condition (Elspot). In this way they ensure the plants generating the power (usually the ones with cost heavy start-ups) a fixed

[7] Countries include Denmark (2 price areas), Sweden (1), Norway (3), North-east Germany (Kontek) (1), and Finland (1). Political bodies have for some years tried to encourage Swedish TSO authorities to perform a much needed fragmentation into more price areas in order to encounter the frequent bottleneck situations.

price and volume throughout the respective hours. A block bid is accepted if the following conditions are met (Elspot):

- If the bid price of a sales block is lower than the average Elspot area price
- If the bid price of a purchase block is higher than the average Elspot area price

Producers can also choose to offer available capacities in the form of balancing-power. This takes place on the market for regulation power: Elbas, which is open as soon as up to an hour before the physical exchange (intra-day trading), opposed to the spot market where deals are closed the day before (Elspot).

Hourly formation of prices

Due to the markets continuous inability to store electricity, the price formations on the Spot market are first and foremost characterized by a number of producers supplying a constantly fluctuating and relatively inelastic demand (Kristoffersen & Stouge 2002). Figure 3.4 shows a principle sketch of the capacities of the systems cumulated according to their individual marginal supply costs – also known as the Merit Order. For each hour, the consumer's marginal utility sets the price (Ravn 2001). One of the largest factors affecting the prices on an average basis is the sea level of the Swedish and Norwegian reservoirs, which determinates the optimal price levels for the hydro owners. High sea levels, being a great incentive to supply, opposite to low levels, where the owners probably will hold back and wait for "better prices to come". Thus, wet and dry years are the overall factor when looking at average prices (Ea Energianalyse 2007).

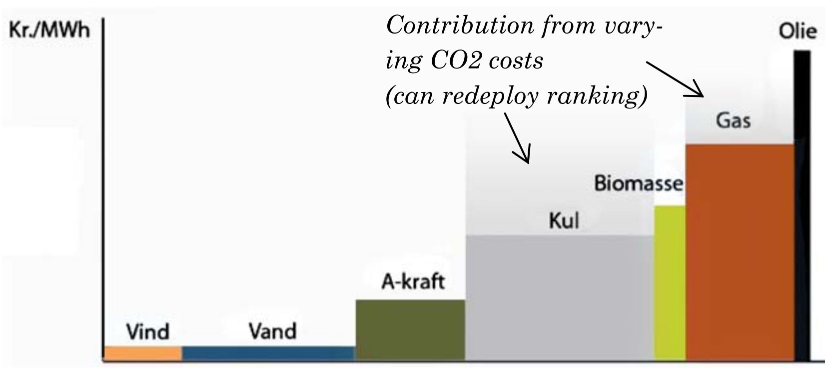


Figure 3.4, A principle sketch of the accumulation of marginal costs of available capacities. It shows how the outcome of price formations varies – typical throughout the different periods of a normal day. Grey shadow areas above coal (Kul) and gas indicate the unknown contribution from CO2 indulgence, which mainly affect the coal proce mora than gas due to higher specific carbon content (data source: Ea Energianalyse 2007).

Cross border trading

When it comes to cross border trading the Nordic electricity market turns out to be a successful example, transmitting large volumes of energy every day (Togeby, Lindboe & Pedersen 2007). The biggest issue of cross-border transmission is the degree of congestions – or bottlenecks. Since capacities often are constraining a perfect market situation[8] the transfer of power (and thereby the settlement of the supply) often results in a final price difference. Market price differences are therefore a symptom of bottlenecks. In such cases, congestions are managed by dividing the price difference equally in favor of the two system operators. The concept behind this: the more prices drop in one area, like in the extreme cases of electrical spillover in West-DK, the bigger the price difference and thus the bottleneck income and the resources for further investments in additional transmission capacity[9].

When speaking of congestions on external transmission, it is important to distinguish between the physical limitation on the sea cables and the more 'artificial' limitation from the variations in announced capacities by the different TSOs[10] – a factor that varies from country to country as shown in Table 3.2. As an example, the rated capacities going to West-DK *from* Sweden and Germany, respectively, are (as a rule) lower than the for transmissions going the opposite direction, and the same can be said about the averagely announced capacities.

Capacities to:	NO	SE	DE
Rated physical exchange cap. [MW]			
Rated physical import	1000	680	950
Rated physical export	-1000	-740	-1700
Average announced cap. [MW]			
Import capacity.	754	507	820
Export capacity.	-721	-494	-1184
Period of no allowed import [%]	0.8	5.5	0.1
Period of no allowed export [%]	0.9	5.1	0.1
Maximum registered exchange [MW]			
Import	1041	810	1634
Export	-1913	-998	-1642

Table 3.2, Average Capacities from NO, SE and DE to West-DK, respectively, showing the sometimes big differences in rated physical capacities the average announced capacities, throughout the observed five year period (2004-09), but also that there are significant differences in the rated capacities for each direction on the same connections (data source: Energinet.dk).

[8] A balanced market with no physical limitations on the supply and exchange of power

[9] One could question the incentive to invest in additional transmission capacity, whereby the bottleneck income will drop. The bottleneck income is ear marked improvements in the transmission system though.

[10] One if the typical reasons why one of the TSOs some hours announces a lower capacity on interconnections than the actual rated capacity is having to protect its transmission system against inner stress levels.

Management[11] of congestions takes place on Nordpool by the specific system operators of concern in union. The decision whether to regulate the market in connection with cross-borders trading, are taken by the TSOs managing the particular connection, and the decisions are mainly based on concerns of security of supply, environmental issues, and the inner stress level of the transmission system, (Togeby, Lindboe & Pedersen 2007). In the end, this means, the decisions often depend on the TSO being most concerned about the inner stress level. The Swedish system operator Kraftnett is statistically more interested in importing than exporting in Southern Sweden. In Table 3.3 is seen that 20 % of the time, no exchange of power takes place on the connection between West-DK and Sweden and, for some reason, 50 % of these hours no capacity is allowed.

	Trade NO	Trade SE	Trade DE
Annually trade [TWh / year] (2004-09 mean)			
Import	3.31	1.63	1.20
Export	-1.62	-0.96	-5.30
Net, Import	1.70	0.67	-4.10
Overall net import	**-1.73**		
Average transmission of:			
Planned import [MW]	633	392	494
Planned export [MW]	-550	-340	-837
Actual import [MW]	588	354	495
Actual export [MW]	-504	-249	-877
Planned trade factor [%]			
Import	59.6	47.4	27.8
Export	33.6	32.1	72.2
No transmission	6.8	**20.6***	0.0

***50,6% of the time, announced transfer capacity is zero**

Table 3.3, Key figures for cross-border trading over a five year period (data source: Energinet.dk).

One could say about theses rated as well as announced interconnection-capacities that – in practical – they could (and should) be the same each way. The subject of the current effectiveness of congestion management in the Nordel area are regularly up for discussion (Togeby, Lindboe & Pedersen 2007)

[11] Congestion management refers to the principles used to handle the physical flow of power across cuts in the transmission grid with limited capacity. (Nord Pool Spot)

Carbon

With the introduction of CO2 quotas[12] the ambition is to promote investments in less carbon based generation technologies, by adding an overall limit to the total emission, and leave it to market forces to decide the 'value' of pollution. This relation is attempted reflected through the grey areas in Figure 3.4 from earlier.

The system is still taking form, and the design of the system is therefore still up for discussion. Some observers fear that too many free CO2 options have been issued, causing a devaluation of the options and thus a low incentive for 'green' investments based on this (CAN Europe 2006). One could therefore argue for a significant cut in the amount free CO2 options. None the less, CO2 emission trading has steadily increased in recent years. (CAN Europe 2006), and will be included in the modeling of production costs of thermal units the later on.

3.3. Heat and power generation – a review of the various technologies

3.3.1. Technical and economical properties

I this section some of the basic properties of the different power generation technologies that constitute the Danish heat and power system today will be explained. Emphasis will be on the parts significant to the construction of the mathematical model – these parts being for example the most frequent or significant types of power units, primarily fuel sources etc.

Power plants and fuel sources

Many of the centralized power plants are focusing on the use of different types of CO2 neutral bio fuels such as wood and straw for fueling one of their blocks – according to their profiles (DONG Energy 2009). Despite of this, facts are that the primary source for generating power in the Danish power system, by far is coal (Dansk Energi 2007). On the heat-production side biomass constitutes around one third of the fuel consumption, as seen in figure Figure 3.5, but still coal and gas represent the main source.

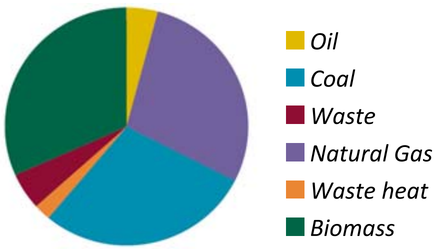


Figure 3.5, Distribution of fuel consumption for district heating (data source: Energinet.dk)

[12] In April this 2000, the European Commission approved the Act on CO2 Quotas for Electricity Production pursuant to the state subsidy regulations. The Act therefore entered into force on 15 July 2000 with effect from 2001. The quota system entails that the individual Danish power companies receive a CO2 emissions permit each year that will gradually be reduced in size (Miljøministeriet 2000).

Regarding production *capacity*, 53.4 % of the total power in West-DK is generated on the central units (all steam units) shown in Table 3.4. This corresponds to 96.9 % of the total central power generation (Table 3.4, Figure 3.6). Two units in West-DK have very little heat output by which they roughly can be characterized as generating condensed electricity, these are: *Nordjyllandsværket* block 2 (NJV2), which is quite old and used only for peak loads (Vattenfall 2009), and *Enstedsværket* (ENV) which represents about 16.4 % of the total el. generation from central units. The pie chart seen in Figure 3.6 below shows the same.

Power units:	Annual (2007) el. production [GWh]			Block name	Rated el. capacity [MW]	Rated heat cap. [MW]
	Number of GWhs	Percentage of total production [%]	Percentage of central production [%]			
Nordjyllandsværket	3191	13.7	24.7	NJV2 NJV3	**225** **410**	**420** **455**
Studstrupsværket	2413	10.3	18.7	SSV3 SSV4	**350** **350**	**455** **460**
Enstedsværket	2111	9.0	16.4	ENV3	**626**	**340**
Esbjergværket	2115	9.0	16.4	ESV3	**378**	**475**
Fynsværket	1762	7.0	13.7	FYV3 FYV7	**235** **362**	**444** **42**
Skærbækværket	897	3.8	7.0	SKV3	**392**	**85**

Table 3.4, Capacity of power units in West-DK (data source: Dansk Energi 2007).

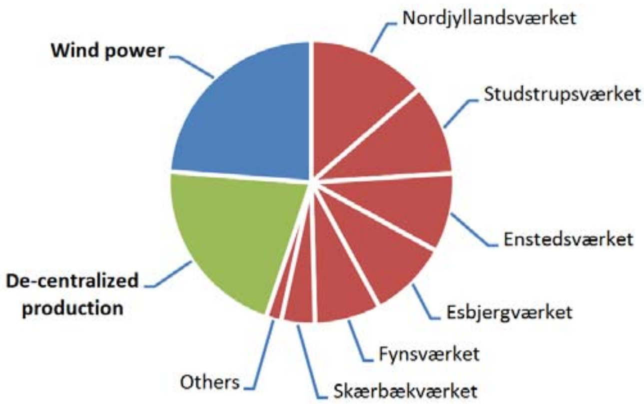


Figure 3.6, Distribution of el. production by centralized, de-centralized and wind units. Centralized production divided by the top six units in West-DK (data source: Dansk Energi 2007).

Extraction and condensing units (central production)

Extraction units as well as condensing units are two types of coal fired steam plants in the Danish Power system. They constitute the main part of the centralized el. production as they produce in the scale of hundreds of Megawatts. While extraction units are CHP plants, the condensing units produce no heat (besides energy contained in the cooling water).

In Figure 3.7 is seen a principle diagram of an extraction unit, where heat is usually extracted at the low pressure turbine and used for district-heating. What distinguishes extraction units and the more conventional condensing units apart is the steam extraction at the low pressure turbine (4, Figure 3.7) and into the fallowing heat exchanger for district heating (6 and 7, Figure 3.7). An energy-efficient technique compared to generation of condensing power. When it comes to the electricity to heat ratio, this technology has a set of degrees of freedom in terms of the ability to vary heat output, going from completely condensed el. generation to a maximum heat defined by the backpressure limit.

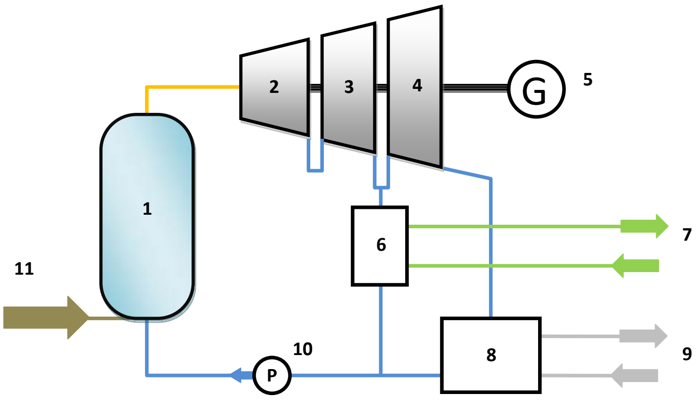


Figure 3.7, A classic example of an extraction unit as seen thermodynamically. The heat-extraction point is located as seen above heat exchanger (6), from which the thermal heat for district-heating is pulled out (source: Akraft 2009).

1. Boiler
2. High pressure turbine (back pressure)
3. Medium pressure turbine
4. Low pressure turbine
5. Power generator (AC)

6./7. Extraction for district heating

8. Low pressure turbine cooling
9. cooling water

11. Fuel (coal)

Although generating heat this way is not entirely free, the loss of electricity generation is rather insignificant. In Figure 3.8 below it can be seen that - at constant boiling power - the marginal loss of electricity from extracting one extra unit of heat is indicated by the ISO-fuel lines (Gronheit 1993). The slopes of these ISO-fuel lines are given by the c_v coefficient. In this project, the marginal loss will be given by c_v = 15 %, corresponding to modern extraction units (Danish Energy Authorities 2005). With an electrical net-efficiency of 45-50 % (condensing), we get an instant, marginal co-generated heat-efficiency of ~300 % as seen in equation (3.1):

$$\eta_h^{CHP} = \frac{\eta_{el}}{c_v} \approx 300\% \qquad (3.1)$$

In reality the ISO fuel lines are more curved as seen in Figure 3.8 to the left. However, these can with reasonable approximation be regarded linear according to Figure 3.8 to the right. The maximum heat output is constrained by the backpressure limit, given by the backpressure value c_m and the maximum capacity of the heat exchanger $P_{h,max}$. When operating in backpressure mode, the electrical efficiency drops to around 39 %, but with the heat output added, the total CHP efficiency (for new plants) can reach a level of 93 % (Danish Energy Authorities 2005). Each ISO fuel line corresponds to an extraction point at one of the low pressure turbine's buckets. The backpressure rate for extraction units is in this project around 0.75 units of electricity per one unit of heat.

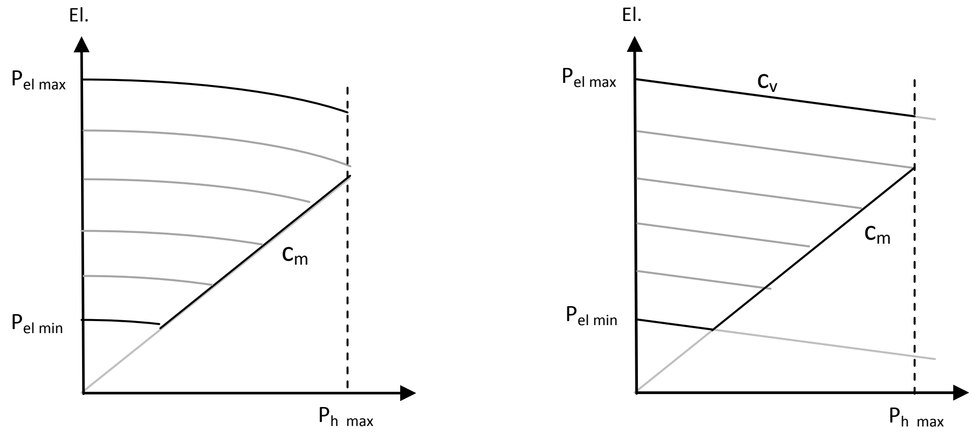


Figure 3.8, The 'curvy' ISO fuel lines (figure to the left), which express heat vs. el. during constant boiler power, can with reasonable approximation be modeled as linear (figure to the right). Maximum heat capacity is given by the heat exchanger while min and max limits on power output are set by the boiler (source: Gronheit 1993).

Unfortunately, the option of reducing the heat output when there is no need for it does not work the other way around, due to the back pressure constraint. Reducing power while producing heat would be convenient in times of low electricity demands and high heat demands, though. A critical disadvantage of these units – in relation to the current system – is that they often are designed for base and medium load, which is reflected in their large physical size, slower up- and down regulation, as well as high investment costs[13]. Hence they are rather expensive start-up (and shut-down) (Dieu & Ongsakul 2007), which can make the operating schedule more complex. In addition, the lower boundaries of the production capacity are relatively high, which can be unsuitable in cases of small load demands.

The operation economy of central units (key figures shown in Table 3.5) is characterized by low fuel- and O&M costs, plus by a very high MWh-specific content of carbon.

Marginal costs, CHP [€/MWh_{CHP}]	**Marginal costs el.** [€/MWh_{el}]	**Marginal cost heat** [€/MWh_{Heat}]	**Variable O&M** [€/MWh_{CHP}]	**CO2 costs*** [€/MWh_{CHP}]
17.97	35.20	31.20	1.80	6.75

Table 3.5. Estimated values of operation economy for extraction and condensing units are rounded. *CO2 quote prices are of course never certain but in this case set to 20 € per ton. Separate marg. costs of el. includes a valueless heat and vice versa (data sources: Danish Energy Authorties 2005, Danish Energy Authorties 2008).

[13] Large power plants such as steam units are usually designed for base and medium load in order to run for many years and thereby to pay off great investments.

Back pressure units (decentralized production)

Backpressure units are a type of, usually small, CHP plants with fixed electricity to heat ratio, as shown in Figure 3.9. The heat and electricity output is often produced on regular gas turbines operating on natural gas, but sometimes also on the more efficient combined cycle units running on a combination of Brayton (turbine combustion) and Rankin (steam) cycles. Efficiencies are in the area of 85-90 % depending on factors such as plant size and -age. The c_m value varies a great deal for backpressure CHP units, ranging from 0.25 to 0.4 for smaller plants to 0.60 to 0.80 for medium to large scale plants (Danish Energy Authorities 2005).

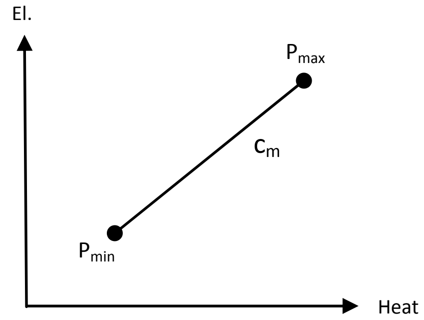


Figure 3.9, Electricity-heat ratio is fixed in relation to the backpressure value.

One of the drawbacks of these plants is the inability to regulate the electricity/heat-relation. In cases where the value of heat greatly exceeds the value of electricity for example, having constrained[14] power generation can affect the plant economy negatively. On the plus side, however, is the fact that these relatively small CHP units are faster and lesser cost heavy to construct.

The operating economy of decentralized units (key figures shown in Table 3.6), is characterized by high fuel costs, relatively low O&M costs plus a low MWh-specific content of carbon (compared to steam coal).

Marginal costs, CHP [€/MWh_{CHP}]	Marginal costs el. [€/MWh_{el}]	Marginal cost heat [€/MWh_{Heat}]	Variable O&M [€/MWh_{CHP}]	CO2 costs* [€/MWh_{CHP}]
27.80	87.00	48.00	2.63	3.97

Table 3.6. Estimated values of operation economy for extraction and condensing units are rounded. *CO2 quote prices are of course never certain but in this case set to 20 € per ton. The marginal costs separate for electricity and heat (Data sources: Danish Energy Authorities 2005 (operating costs), Ea Energianalyse 2006 (fuel price)).

[14] By forced el. generation is meant the condition of having to produce either heat or electricity in order to produce the opposite, cf. the fixed electricity to heat ratio.

Wind turbines

Wind turbines are usually distinguished between as on- and off shore types, respectively. In 2008, the total West-DK wind capacity was divided as follows; Land mill capacity 2232 MW and offshore capacity 160 MW. Roughly stated, offshore wind power output can be controlled (by down scaling), while land mills are autonomous in relation to power control. Whereas land mills are characterized by geographically being spread, offshore turbines are usually implemented as concentrated wind farms at sea, where wind conditions are more extreme. These relations are reflected in the wind profile comparison seen in Figure 3.10 and Figure 3.11, of which it can be seen that offshore wind production reaches its maximum rated power much more frequently throughout a year than onshore. It is also seen that the peak situations which usually causes electrical overload, is more likely to occur when up scaling offshore capacity.

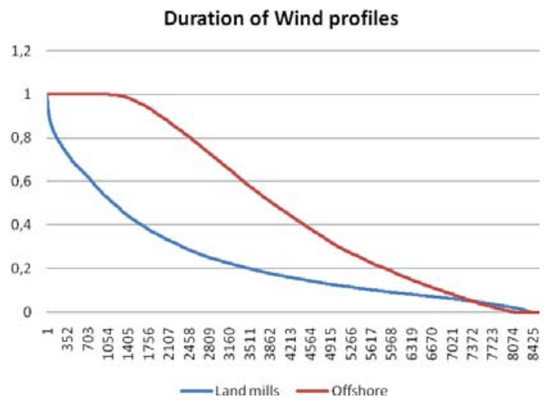


Figure 3.10, The duration of the profiles for offshore and onshore mills, respectively, compares the effects of the units being spread (land mills) to locating them within a limited area (red). Profiles are scaled according to the maximum value.

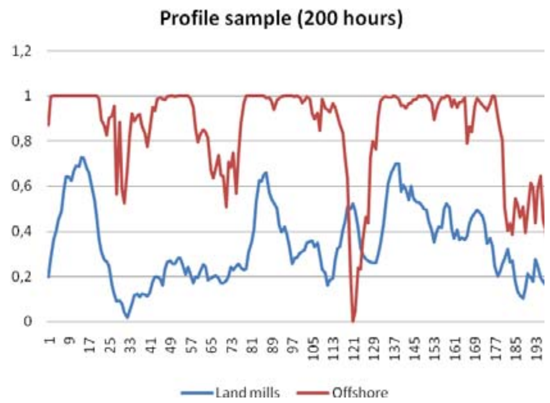


Figure 3.11, A close up of a 200 observation point sample of the same data as shown in a) shows that the total offshore production reaches the maximum level (rated power) quite often.

3.3.2. Technologies for increased flexibility in electricity production

The term flexible electricity production covers a number of instruments that can increase the range of freedom of which heat and electricity production can act within. In this section some of these emerging technologies – technologies which impact the current discussion of how to design the future power system – will be explained, cf. research question 3).

Heat pumps and electrical cartridges

Heat pumps and electrical cartridges are basically instruments for transforming electricity into heat. Heat pumps are thermal systems using electricity for extracting heat from the air or ground into the air or water systems. These systems have an efficiency of 3-400% depending on size (Energinet.dk 2009) and type (for example air-to-air). Electrical cartridges are much simpler, and can be compared to boiling water using electrical resistors with an efficiency of maximum 100 %. The technology is cheaper on short-term, though. Investment costs are estimated to around 0.7 M€ and 0.2 M€ per MW installed capacity for heat pumps and cartridges respectively. The marginal O&M costs seems a bit uncertain and changeable, but it is estimated that heat pumps cost within the range of 0.2-2 €/MWh[15] depending on size and type (Energinet.dk 2009).

Turbine bypass

Normally, when wanting to produce more heat on extraction units, the backpressure value c_m quickly limits the heat production by maximum allowing ~130 % heat for each unit of electricity generated. With the increased wind capacity of the future, it is likely that heat often will be more needed than electricity, and thus making backpressure mode a problem for the energy system. By doing a complete, or perhaps partial, bypass of the high-pressure turbine, the backpressure limit can be disregarded.

A turbine-bypass might in theory concern all steam units, but as extraction units already are connected to the local district heating-system, adjusting for this may initially be more feasible. In this project, the concept of bypass operation (BPO) means having an option to *fully* bypass the high-pressure steam turbine and thus only produce heat when electricity being less wanted. The idea is that this can last for just a couple of hours as well longer, if necessary.

BPO might increase the dynamics of the interplay between electricity production and the district heating system, which consequently may save costs for the plant owner as well as for society, no longer having to produce cheap electricity. It has been assessed that there theoretically is a potential for modifying existing extraction units, in the Danish power system, into having partial as well as full scale bypass option (Ea Energianalyse & Risø/DTU 2009). Only the full scale bypass option will be of concern in this project, since partial scale bypass will complicate the modeling unnecessarily. Figure 3.12, a modified version of Figure 3.7, explains where in the circuit the modification could take place, while the el-heat diagram in Figure 3.13 shows how bypass works on a theoretical level. When operating in bypass mode, the minimum to maximum heat range is assumed given by the minimum boiler power (multiplied by the CHP efficiency) as well as the maximum capacity of the heat exchanger.

[15] Fixed O&M costs are considered (xx tech) to be ranging from 1,000 to 10,000 €/MW/yr and variable to be zero. Value above is calculated from a full load factor of 50%.

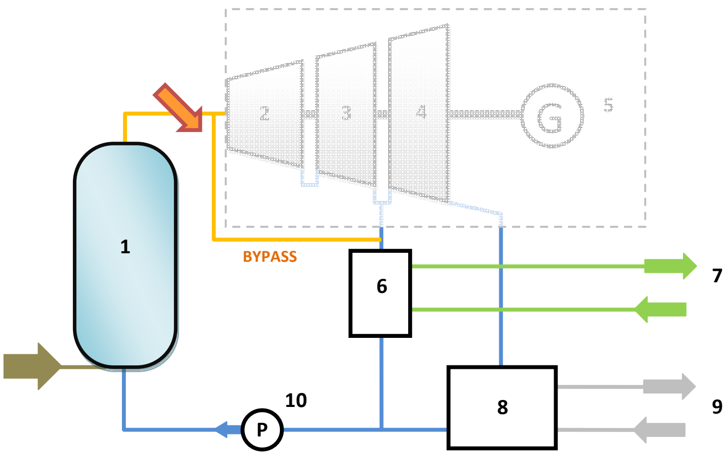


Figure 3.12, Extraction unit with bypass. The valve would likely be situated before the high-pressure turbine (2).

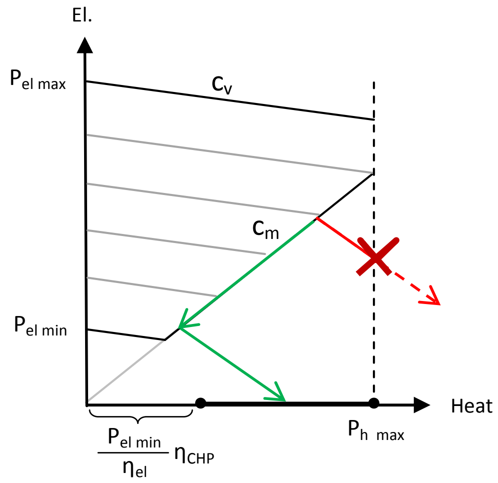


Figure 3.13, Bypass-switching in theory. Note the lowering of the production in order not to exceed the maximum heat limit.

In practical, it will not be possible to momentarily switch into bypass operation, since the existing components for heat exchange are not designed for absorbing the entire boiler power. Before performing the 'switch' the boiler power would as minimum have to be turned down to a level where the energy flow through the high pressure turbine – which at backpressure mode is given by equation (3.2) – is below the maximum heat limit.

$$P_{Boiler} = P_{el} + 0.15 \cdot P_{Heat} \approx 300\% \qquad (3.2)$$

The short term economy (or variable costs) of bypass operation is relatively unknown. That switching between normal and bypass operations is constrained by the up- and down regulation gradient of the units however, might point at a hidden loss of value – especially for the smaller bypass periods.

In this project, full scale bypass is regarded feasible for all central units, regardless of what technical obstructions each central unit of the Danish power system may have.

Boilers

The basic function of boilers is to produce heat for the district heating system. Boilers as heat producers exist already in the current heat systems – especially in combination with waste incineration and biomass-fuels. The economy of boilers is determined by the heat exchangers efficiency (which normally ranges from 85-90 %), the fuel used, and finally; the O&M costs (which can be relatively high for waste incineration and biomass units (Energinet.dk 2009). Waste as a fuel is in principle free (it is going to be burned anyway), but given that waste is not the most adequate energy source it will be excluded later on in the modeling.

Capacity extensions on interconnections

The strengthening of the flow between price systems through building new connections is a well known tool for system operators. In recent years, deciding whether the establishment of a new connection should take place or not have been determined on the basis of bottleneck revenues. Due to increased bottleneck income in the Nordel area the later years, Nordel predicts a feasible positive economy for a range of potential connections (see Figure 3.14). The decision to fallow these through has not taken place though.

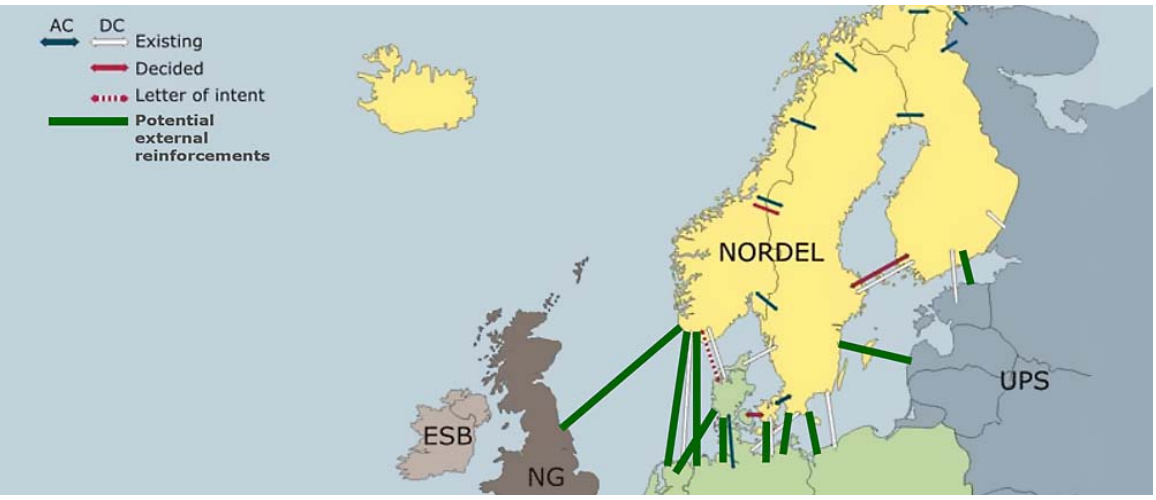


Figure 3.14, Reinforcement of external Nordic interconnections in general shows a positive cost-benefit. Potential reinforcements are not prioritized. The proposed re-enforcements are said to be not necessarily mutually exclusive (Nordel 2008)

Establishing new interconnections is very cost heavy with investments in the order of billions of Euros sometimes. At the same time, despite of the system load issues mentioned earlier in Chapter 1, it is an important tool for balancing markets – especially with the increasing wind capacities being installed in North-Europe.

Energy storage technologies

With the increasing awareness of the impacts of large wind penetration on the market systems, various technologies for storing energy have been in focus. Regarding the heat, storage is already possible (and widely used) in the form of accumulations tanks, creating a peak-load buffer or perhaps withholding heat for hours with more favorable heat or electricity prices. When it comes to the electricity however, technically and economically feasible methods for withholding electricity for sale in hours with better prices are still lacking. So far, the biggest 'battery' the system has at its disposal is still the Nordic water reservoirs.

Energy storage on either the heat side or the electrical side will not be a topic of further evaluation in this project, as the model have not been given this property. This way, electricity- as well as heat demands will be balanced momentarily.

Chapter 4.

The impacts of wind power on price formation and production patterns

4.1. The impact of wind power on the Danish energy system today

In order to put the impact of increased wind power into perspective, plus in order to model the future scenarios, knowledge on the effect of wind power today is required. The aim of this section is therefore to analyze and study the effects of wind power on today's energy system in western Denmark. The chapter is dedicated to an exhaustive survey of the parameters of the system which can be related to the occurrence of critical price formation, and through a statistical approach, the productions patterns of situations with critically low prices will be analyzed.

Data used for the study have primarily been purchased from the Danish TSO Energinet.dk. Observations range over a five year period from 2004 to 2009. Heat production data from central and decentralized units is 2001 data from a data set used to signify a 'Normal year' in the Balmorel model (Ravn 2001).

4.2. Basic characteristics

4.2.1. Demand characteristics

Figure 4.1 below shows the monthly variations in electricity and district heat consumption in West-DK (in 2001). What is characteristic about the electricity consumption is that it despite of the seasons seems constant throughout the year, whereas the heat level varies much more. This pattern can be seen as a symptom of widespread remote heating and more rare electrical heating, which, compared to Sweden and Norway where electrical resistors are the main source for household heating, is unusual.

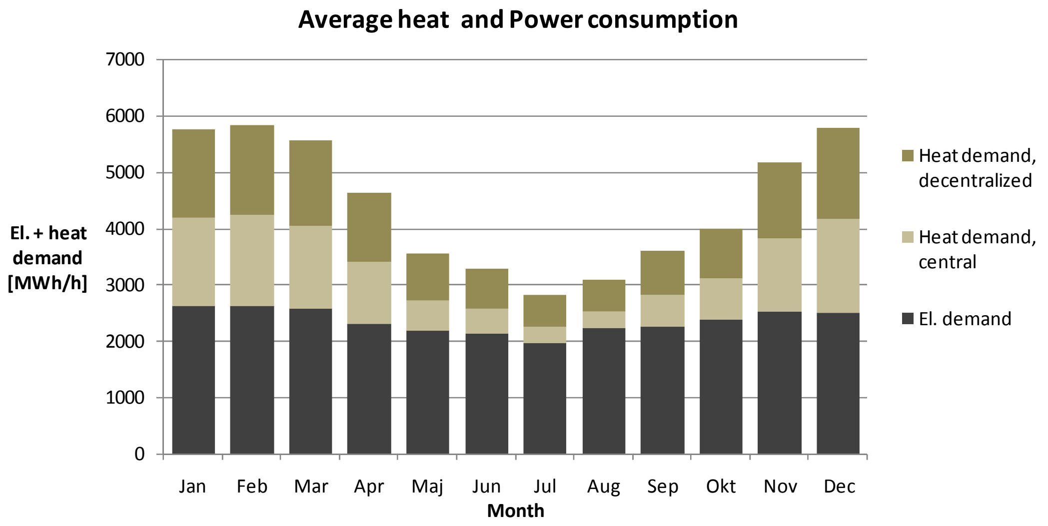


Figure 4.1, A monthly distribution from 2001 of heat and el. demand showing great variations in the produced district heat, as well as a weak influence on el. demand (Data source: Energinet.dk).

Although the CHP concept might seem great as a concept for improved energy efficiency, the insensitivity of the electricity demand towards season variations, combined with the much more variable demand for co-generated heat, might contribute negatively to the problem of high quantities of forced electricity in wintertime. This is due to the constrained electricity-heat interplay described earlier in section 3.3.1.

In Figure 4.2, showing the average consumption by hours (instead of months), a daily variation in the consumption of electricity and district heating, respectively, is seen. Although one could argue that taking the average of the entire year would give an unrealistic picture of the dynamics, it is generally the case that heat and electricity demands are more regular and predictable than for example wind patterns.

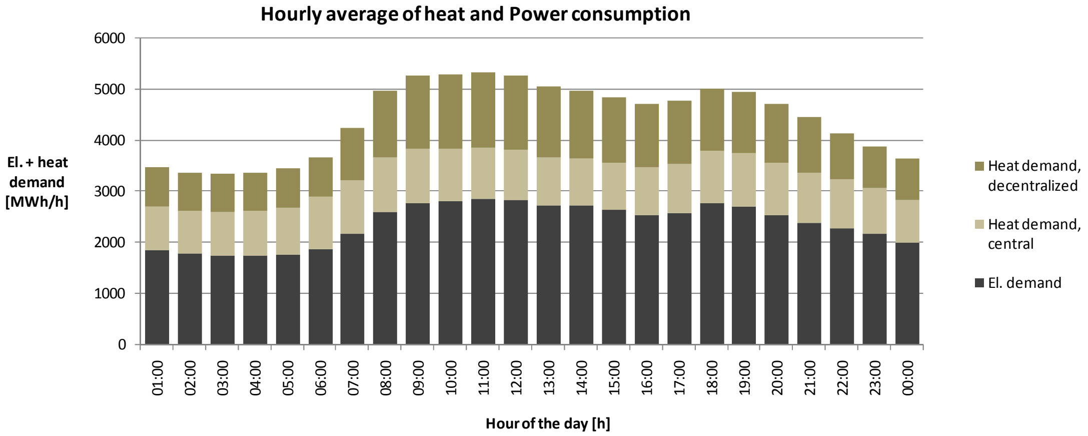


Figure 4.2, An average, hourly distribution from 2001 of heat and el. demand showing the classical 'camel-shape' for both distributions (Data source: Energinet.dk).

4.2.2. Production characteristics

The energy demands showed in the previous figures are balanced by a central, decentralized, and wind production, respectively plus import. In Figure 4.3 below the 2001 monthly average of the electrical side of this balance is seen – including a comparison of the el. demand of the same period, indicating the net import/export of the given months.

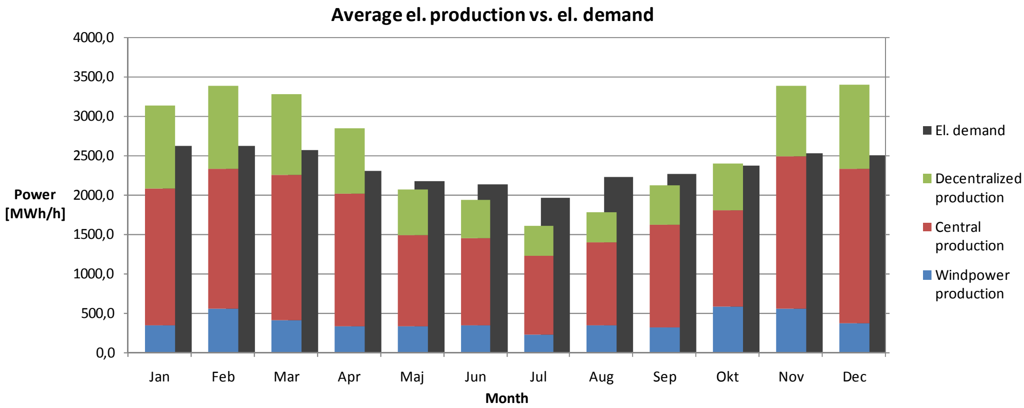


Figure 4.3, Average, monthly distribution of electricity generation by central, decentralized and wind production (from 2001), compared to demand shown in Figure 4.2 (data source: Energinet.dk).

The most striking about Figure 4.3 is the fact, that the average electricity production never quite fits the corresponding electricity demand, generating more electricity than required in the winter season and less in the summer. This way, the system goes from being a net exporting area during cold times to an import area during more hot periods. Another characteristic is the varying wind production throughout the year, with as much as a factor two averagely difference between the 'valley months' like July and the windy months November and December.

From the camel-shaped hourly distribution in Figure 4.4 it is also seen that the level of wind production, even when looking at the total average over the year, increases by a factor of around one third. Seen from a balancing aspect, it might be convenient that the wind averagely peaks in the middle of the day. Furthermore, we can see no great tendencies of varying import within the average hours.

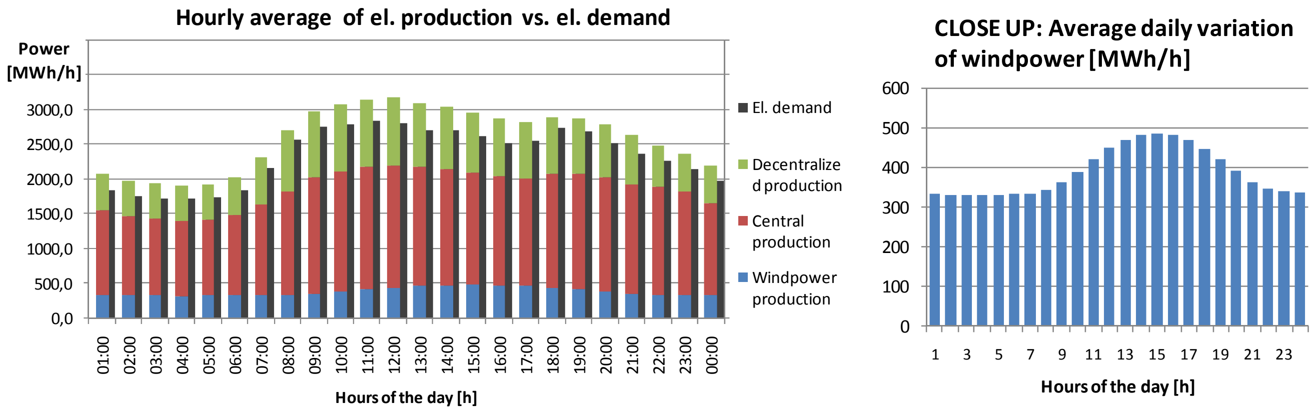


Figure 4.4, Left, is the hourly average of production and consumption showing that the differences in production and consumption, previously seen on a monthly basis, seems to be distributed to all hours. Right graph is a close-up of the wind profile, showing that also wind varies throughout an average day (Data source: Energinet.dk).

In terms of co-generation, we saw in section 3.3.1 how backpressure units have a fixed heat-electricity ratio given by the c_m value, and that extraction units have a variable power-heat ratio. In this project, the assumption is that backpressure units generally constitute the decentralized production, as extraction units constitute the central production. In order to confirm this, Figure 4.5 and Figure 4.6 show two plots of the average heat production divided by the electricity production in the particular hour – this on an hourly and monthly basis, respectively (both standardized). As expected, the power-heat ratio of the decentralized productions is locked (with an estimated c_m value of 67 %, giving 1.5 units of heat per unit electricity unit), while this relation for central el. production varies during an average day as well as throughout the year (with a factor of 0.43 units of heat in summer season[16] to 0.81 during winter, per generated unit electricity). This way, production data supports the fact that decentralized backpressure units, as mentioned earlier, are better at delivering heat than electricity, due to lower cm values – the opposite being the case for the central units. The calculated power-heat ratio seen above makes decentralized power production a good indicator for heat demand.

[16] With summer season defined as May to October.

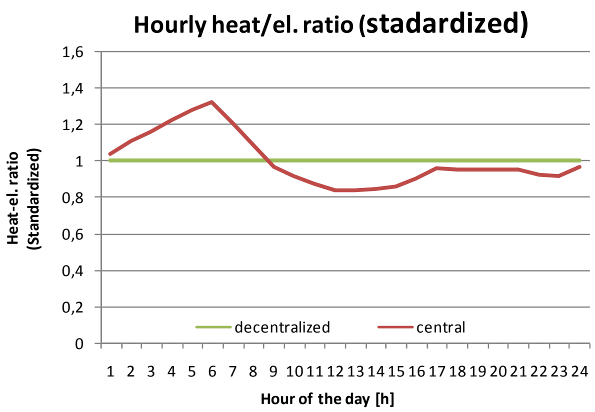


Figure 4.5, Heat divided by electricity, distributed by hourly average. The plot shows that heat/el. ratio is fixed for decentralized production (backpressure units) and varies for central production (steam units), producing most heat in the morning (data source: energinet.dk and Ea Energianalyse).

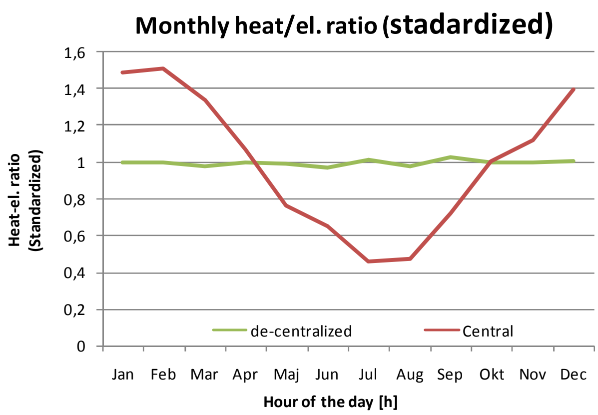
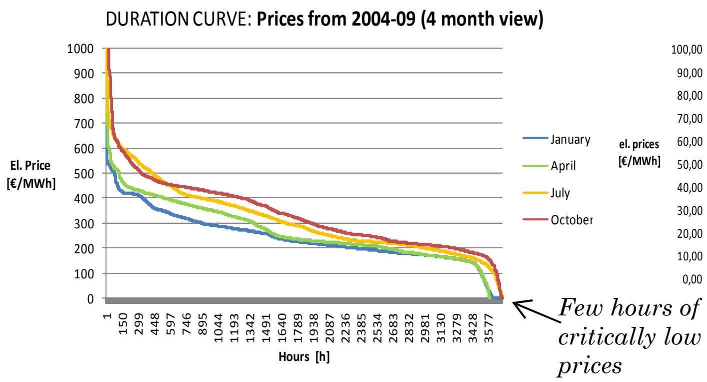


Figure 4.6, Same as in Figure 4.5, distributed by monthly average. Again here, decentralized production is fixed due to an overweight of backpressure units within, as central production varies, mostly producing heat in the winter time and more condensing el. in the summer (data source: energinet.dk and Ea Energianalyse).

4.3. Windy system behavior

In the following section a study of the production patterns, as well as the price formations, when exposed to increased wind power is presented. When observing the data in the five year dataset, it becomes clear that the amount of hours of critical low prices is not it overwhelmingly (from a statistical point of view). This trend is also seen in Figure 4.7.



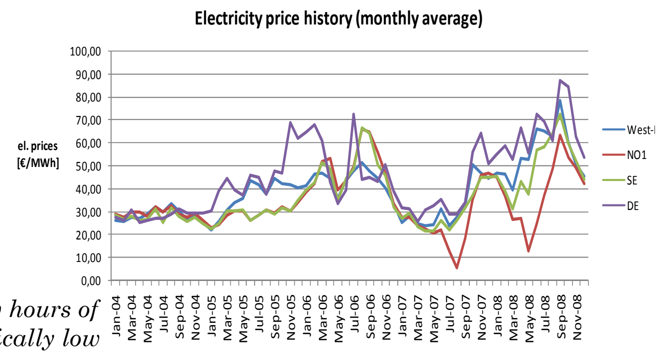


Figure 4.7, Comparison of a monthly sample of price durations from West-DK over the observed years showing statistically higher el. prices in October and July and lower prices in January (data source: Energinet.dk).

Figure 4.8, Comparison of monthly average of prices in the three price areas connected to West-DK. Interrelated variations are normally due to transmission capacity limitations (internal as well as external) (data source: Energinet.dk).

Within a normal year, critical low-price hours have an expected share of around 2 %. However (as seen in Table 4.1 below) this share varies from year to year. The main reason why the occurrence of critical low price hours is still relatively rare in today's system is that a combination of more extreme parameters often is required. Parameters like high wind penetration, cold nights, the Nordic rainfall or reduced interconnection capacity, makes it harder to balance the generated electricity perfectly. The numbers in Table 4.1 substantiate this relation.

YEAR	Critical low-price hours [h]	Share [%]	Wind capacity [MWh/h]	Decentral el. ~ heat demand [MWh/h]	El. spot prices [€/MWh] NO1	SE	DE (EEX)
2004	207	2.4	555	715	219	209	212
2005	82	0.9	573	683	217	222	343
2006	156	1.8	527	624	367	359	379
2007	**295**	3.4	**635**	**561**	**192**	225	283
2008	107	1.2	591	561	292	381	490
Mean	169	1.9	576	628	257	279	341

Table 4.1, A comparison of annually key figures in relation to low prices (data source: Energinet.dk).

From Table 4.1 can be interpreted that 2007 was the 1) windiest, 2) warmest and 3) wettest year out of the five, plus 4) the year with the highest number of critical low price hours – an interpretation based on the following conditions:

1) In 2007 the wind capacity was averagely 635 MWh/h compared to the remaining years with a wind capacity ranging from 527 MWh/h in 2006 to 591 MWh/h in 2008.
2) Assuming that the electricity generation from decentralized production can be interpreted as the heat demand, cf. section 4.2.2, 2007 can be interpreted as the warmest year, being the year with lowest decentralized electricity production.
3) In 2007 the electricity price in Norway was the lowest out of the five years indicating the greatest rain fall.
4) The number of critical low price hours was 295 in 2007 which is more than tripling of the number in 2005, and almost twice as high as the number in 2006.

Opposite 2007, 2006 was dry (cf. the high Nordic spot prices), much less windy and not very cold, and thus not parameters causing critical low price hours. Nonetheless the number of critical low price hours was twice as high as in the year before, 2005, which – when comparing – was colder, windier and wetter, and it should be the other way around. A reason for this could be that the congestion management in the critical price hours worked better in 2005 than in 2006. For backing this, the annual average TSO managed export capacities from West-DK *in hours with low prices* is shown in Table 4.2

where, as seen, the possibility of export was better in 2005 than 2006, indicating a more effective congestion management (Table 4.2). Still, this might not explain much of the variations.

	NO1	SE	DE	Total
Max. export	-1000	-740	-1700	-3400
2004	-902	-305	-1179	-2385
2005	-883	-335	-1088	-2306
2006	-477	-277	-1019	-1773
2007	-737	-262	-1162	-2161
2008	-624	-403	-1221	-2248

Table 4.2, Annual average of TSO managed export capacities from West-DK in hours with low prices, showing 2006 as a year with the most reduced capacities (data source: energinet.dk).

The two parameters normally being regarded as main contributors to electrical overflow, causing prices to drop to around zero, are high wind production and heat-constrained power generation. Figure 4.9 and Figure 4.10 both show the relation between price distribution (along the x-axis) and the total production from wind-, central- and decentralized power units (on the y-axis). Whereas the graph to the left shows the total production in absolute values, the graph to the right shows the production scaled according to demand within the given price range. What becomes clear when observing the two figures is that the factors at play, when the prices drop, are: increased wind capacity, waning el. demand and a constant power generation from central and decentralized units. Prices in the area from 0 to around 20 €/MWh could be safely regarded as heat constrained power generation, meaning that the variable costs no longer represents the marginal utility in the electricity market (will be explained later in section 5.2.3). The graph to the right indicates that when prices drop within the range of 0-10 €/MWh, the production/load ratio are expected to be between 1.2 to 1.4.

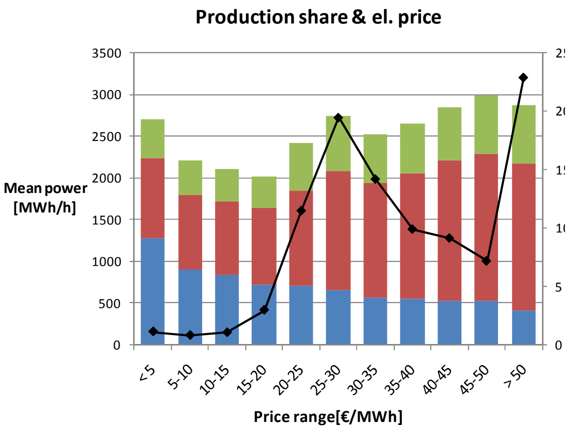


Figure 4.9, Production shares by price. Data source: Energinet.dk

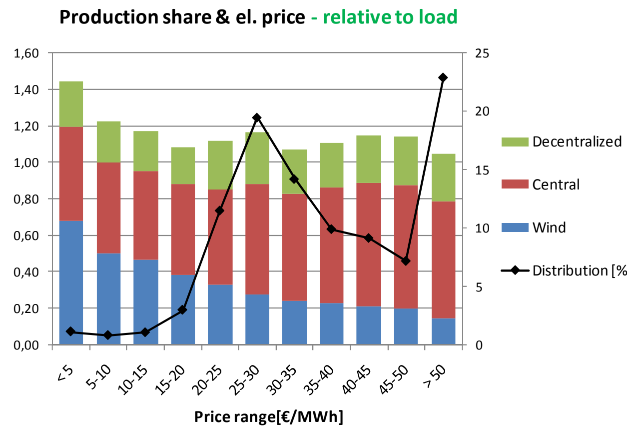


Figure 4.10, Production-load ratio by price. Data source: Energinet.dk

The combination of increasing wind production and decreasing electricity demand, within the lower prices (as mentioned earlier), is seen in Figure 4.11 below.

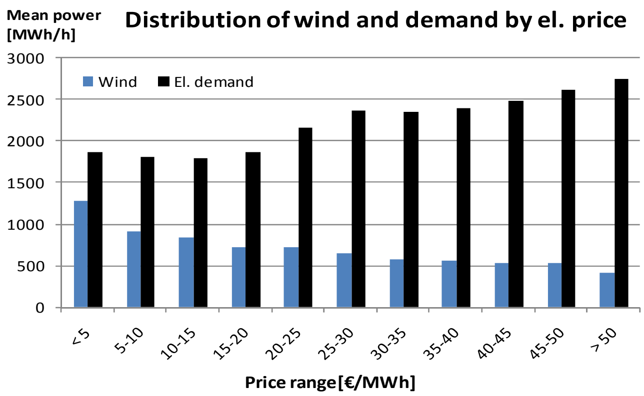


Figure 4.11, The distribution of wind and demand by el. price ranges, shows an expected increase in wind production as well fall in el. demand in line with falling prices. Data source: Energinet.dk.

4.4. The characteristics of critically low prices

4.4.1. The daily distribution of low prices

The decreasing electricity demand may just indirectly serve as explanatory parameter for low prices. The reason for this is presented in Figure 4.12 (below to the left), which shows the distribution of hours with critical low prices of an average day. A great accumulation of these hours are seen between mid-night and morning with a peak around 4 am. Also, as the graph is layered according to the monthly average, there seems to be a significant higher level of low prices in winter season, especially in January. This could be connected to a greater amount of heat-constrained power generation, although a month like May has low prices too. The low prices in May could be due to the great amounts of melting water in the Nordic reservoirs in that period though. These presumptions seem to be supported by

Table 4.3, which shows the frequency of different import/export situations between West-DK, and Norway and Germany, respectively. It is the general interpretation that the accumulation of low prices around 4 a.m. and 5 a.m. (besides from lower el. demand) is caused by the power-up of the central units, which need to start up a couple of hours before the morning consumption peak (probably for heating the accumulation tanks), in order to meet the first load. The same trend is seen around 4 p.m. and 5 p.m., although in much smaller scale, which is just before the second peak load of “the camel”, cf. section 4.2.1.

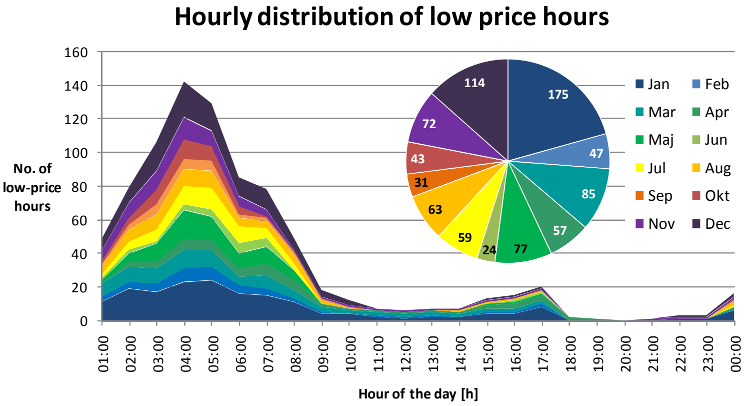


Figure 4.12, Distribution of low prices by daily average as well as monthly (data source: Energinet.dk).

IMPORT FROM / EXPORT TO:

5 year average of:	NO **ex** DE **ex**	NO **ex** DE **im**	NO **im** DE **ex**	NO **im** DE **im**
May	0,0	37,7	31,2	9,1
Dec + Jan	55,7	43,9	0,0	0,0

Table 4.3, Low prices: Characteristics of import from, and export to, Norway and Germany, respectively (**im** = import from - , **ex** = export to -). The reason that numbers as a total does not equal 100 is that sometimes transmission is zero (data source: Energinet.dk).

Not all low prices in West-DK are created internally. From

Table 4.3 was seen that, in January and December, 99.6 % of the times with low price occurrence, the West-DK area is *exporting to Norway* (while simultaneously importing from Germany in 43.9 % of the cases). This indicates that low prices in these winter months are likely to be caused by a combination of wind and CHP in West-DK. May however, is a month where some of the low prices seem to be created in the Norwegian production system as 31.2 % of the time, Norway are exporting, indicating a possible overflow in the reservoirs in the fall season.

In Figure 4.13, Weekly distribution of critically low prices (data source: Energinet.dk). is seen the distribution of critically low prices during a week. Not surprisingly, Sunday is a day with greater probability of experiences these hours due to lower consumption. What is interesting is that Monday has the second highest amount.

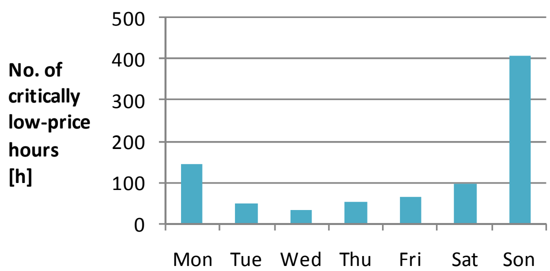


Figure 4.13, Weekly distribution of critically low prices (data source: Energinet.dk).

4.4.2. Durations

Figure 4.14 below shows a two-day sample taken from the end of 2007 in which a couple of periods with low prices of various lengths occur.

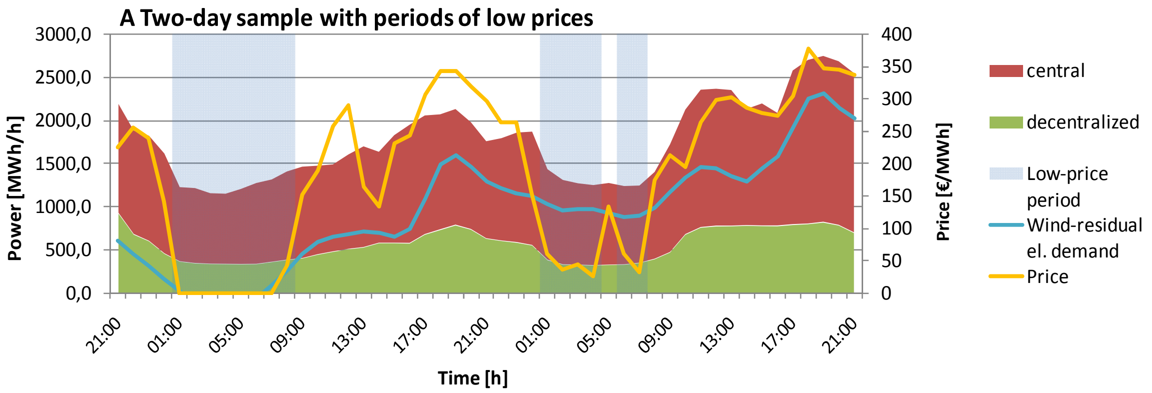


Figure 4.14, The graph displaying thermal production, the spot price as well as the wind-residual el. demand shows that it is hard to see, if the thermal production responds to the falling prices at all. (data source: Energinet.dk).

In the sample shown above it looks as if the thermal production does not really react to the critical prices – nor when the wind-residual demand is less than zero – in the way they ideally should; by reducing el. generation. The occurring reduction might as well be an effect from fallowing the normal profile of demand for co-generated district heating. Or to put in another way: the el. generation is most likely constraint by something else than the electricity price. However, the exact amount of latent el. generation remains more or less hidden within the numbers.

Because central power units – opposed to smaller gas fueled decentralized units – are not capable of responding quickly to load fluctuations, the duration of low price periods becomes important when discussing the lack of down regulation. In this connection, a duration curve showing all durations of low-price hours registered from the five year observation period is to be found in Figure 4.15 (below, left). Figure 4.16 shows the same hours distributed by month. It also shows the amount of periods lasting longer than three hours – in this way ignoring the shorter low-price periods. The short low-price periods make up 64 % of the total 249 *periods*, and the remaining 89 periods last more than three hours. However, these 89 periods correspond to 67 % of the total *amount* of low-price hours – a statistical information that can be useful in terms of a possible down-regulation of the electricity generation on central units, when being concerned about their thermal dynamic properties.

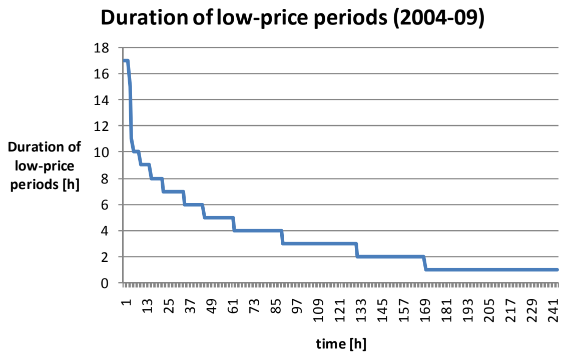


Figure 4.15, Plot of how low-price periods are distributed according to their duration (data source: Energinet.dk).

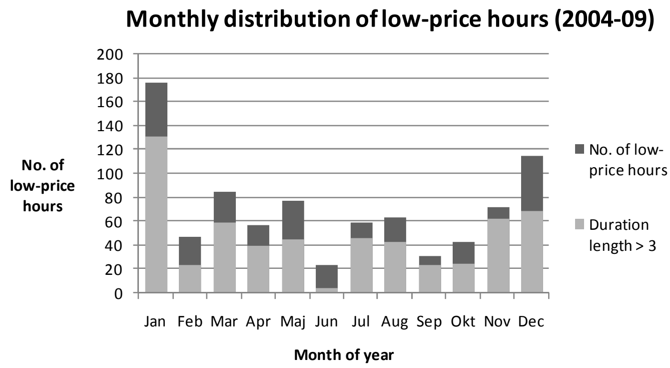


Figure 4.16, Annual distribution of low prices, indicating the share belonging to periods being at least 4 hour long (data source: Energinet.dk)

When discussing the lack of response to the el. prices from the thermal units, one of the presumptions are, that it is more likely that the motive for the "keep on going" through these critical operation hours has to do with the practical issues regarding the up- and down regulation rather than economical issues (Ea Energianalyse 2007). The same reason which probably underlies the motivation behind introducing block-offer bid-type on Elspot (cf. section 3.2.4). Therefore, an attempt has been made to analyze the correlation between the duration of the low-price periods and down regulation of the el- production (the respond tendencies), in order to make out if the lacks of down regulations are due to inconvenient short periods or other restrictions. Figure 4.17 shows a plot of the average production in the low price period divided by the average production in the four previous hours as a function of low-price periods. A linear relationship is estimated (see Figure 4.17) which shows, that for every hour longer the low-price period last, the relative change in el. production fall by a factor 0.0162. This means, that there might be a slight tendency to down regulate as the duration increases. However, many important explanatory factors for down regulation are left out of the equation, since the systematical part of the equation (the duration of low prices) only explains 8.31 % of the variation in the data (the R^2 value on 0.0831). The tendency to down regulate could also be a reflection of the morning 'valley' in consumption of heat and electricity, which as previously shown, is the most frequent period of the day in regards to low prices.

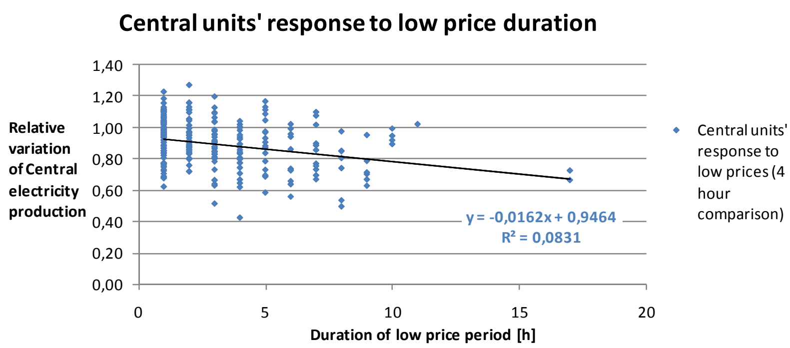


Figure 4.17, Plot of relative comparison of el. generation from central units in low-price periods and in the four previous hours, which shows that the length of the criti-

cally price-periods has no significant influence on whether central units would down-regulate. The relative variation is calculated by division of the four previous hours (data source: Energinet.dk).

4.5. The relation between critically low prices and wind production, decentralized production, central production, demand, capacity and hour of the day

So far it has been shown, that there is a relation between the occurrence of critically low prices and the wind production, the decentralized production (cold nights), the time of the year (more or less equivalent to cold nights/decentralized production) and the hour of the day. In the fallowing, however, an estimation of the exact relation, when taking more explanatory variables into account at the same time, will be presented. Focus will be on the effect of wind capacity, although the other factors are of relevance too.

The primary objective is the causing of critically low prices (either critically low, or not), and not the effect on the electricity price 'in general'. The relation is therefore estimated using logistic regression, where the *probability* of an event is modeled, and the dependent variable is binary (price being critically low: yes/no (contrary to linear regression where the dependent variable is continuous)).

The probability of critically low price (CLP) is then given by:

$$P(Y = CLP) = \frac{\exp(\alpha + \beta_1 wind + \beta_2 demand + \beta_3 decentralized + \beta_4 central + \beta_5 hour + \beta_6 capacity)}{1 + \exp(\alpha + \beta_1 wind + \beta_2 demand + \beta_3 decentralized + \beta_4 central + \beta_5 hour + \beta_6 capacity)}$$

- and is a function of the wind production *wind*, the demand *demand,* the decentralized production *decentralized,* the time of the day *hour,* the central production *central* and the total allowed external transmission capacity *capacity* (the central production as well as the allowed external capacity is included as predictors in the model in order to control for the possible effects). All independent variables are continues and stated in step sizes of 0.1 GWh, except for '*hour* of the day' which is divided into the fallowing four categories: 9 pm to 2 am, 3 am to 8 am, 9 am to 2 pm and 3pm to 8 pm (simplified: night, early morning, morning and afternoon).

The values for the constant α and the β weights are calculated through maximum likelihood estimation (SPSS helps us doing this, for further elaboration see Meyers, Gamst & Guarino 2006). For tests and thoughts on the validity of the model see appendix 11.1.

As the result of the model estimation shows (Table 4.4 below), all the variables have a significant effect on the probability of critically low prices except *hour (3 pm to 8 pm)* whose effect is not statistically different from *hour (9 pm to 2 pm)* (the reference category). The effect of *hour (3 am to 8 am)* on the other hand is highly significant with odds 2.309 which indicates, that in the period from 3 am to 8 am, critically low prices are 2.308 times more likely to occur than in the period from 9 pm to 2 pm when controlled for wind production, demand, decentralized production, central production and allowed external capacity (held constant). This means that the hour, or period, of the day *alone* affects the probability of critically low prices, which could indicate that the probability of heat-constrained electricity could be much higher in that period (being independent from low el. demand). To put this into perspective, it was mentioned that some CHP units usually prepare for the first daily peak in heat demand by accumulating heat in the hours up to this event. The significant result proves that something in those hours – besides low consumption and the additional factors – are creating the perfect conditions for low prices, and that this could possibly be the "morning preparation" causing heat-constrained power to "block" cheap capacity (like wind) from the el. supply. Remembering that a part of the heat producers are paid for the electricity through the tariff agreement, it is likely these producers will not have to pay attention to this problem, thus increasing the probability of critically low prices.

It is also apparent from the table that for each extra 0.1GWh produced in wind production, critically low prices are 1.256 times as likely as before this unit was produced (for example when going from 5.0 GWh to 5.1 GWh). For decentralized production, the odds are 1.247.

Explanatory variables	**Log-odds**		**SE**	**Odds**
Wind production	0.228	***	(0.007)	1.256
Demand	-0.494	***	(0.021)	0.610
Decentralized production	0.221	***	(0.019)	1.247
Central production	-0.065	***	(0.014)	0.937
Hour (9 pm to 2 am)				
Hour (3 am to 8 am)	0.836	***	(0.089)	2.308
Hour (9 am to 2 pm)	0.381	*	(0.159)	1.463
Hour (3 pm to 8 pm)	0.215		(0.164)	1.240
Capacity	-0.089	***	(0.008)	0.915
Constant	5.837	***	(0.0358)	342.723

Note: * $p < 0.05$ ** $p < 0.01$ *** $p < 0.001$

Table 4.4, Results of logistic regression: log-odds (and odds) estimates with standard errors in parenthesis (N=43,848)

In Figure 4.18 below, the predicted probability of critically low prices as function of wind production is shown, when holding demand, decentralized production, central production, external transmission capacity and hour of the day, constant (giving four different combinations). First of all, it is worth mentioning that the probability of critically low prices increases as the wind production increases, approaching 100 percent at large production (maximum wind production in the data is 2230.3 MWh). Taking the black line – the effect of wind production when holding demand, decentralized production, central production and capacity at their means and the period of the day at 9 pm to 2 am – as reference, it is shown that the probability of critically low price increases *when the decentralized production increases*, or, to put it another way: when it is cold (blue line, decentralized production held at maximum). Likewise, the probability increases when the external transmission capacity and the demand decreases (red and green line, capacity and demand at minimum values, respectively), and when the demand is held at its minimum, the decentralized production at its maximum, the central production at its mean and the external transmission capacity at its minimum, the probability of critically low prices varies from 0.84 to 0.99 as function of the wind production.

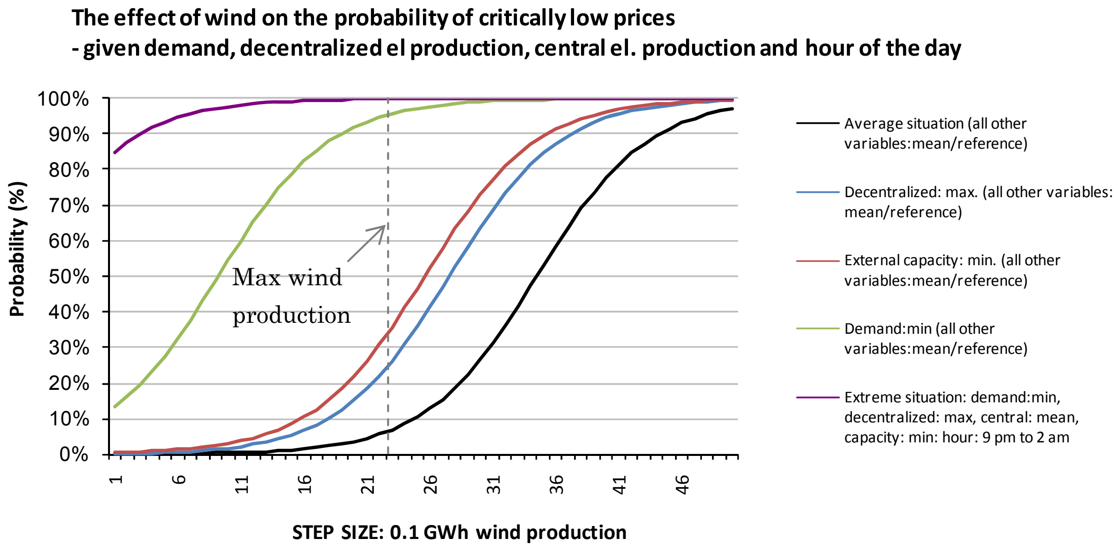


Figure 4.18, The predicted probability of critically low price as function of wind production for four different profiles. It has been checked that no min or max values are so-called outliers. The lines can be interpreted this way: black = average situation, blue = cold day, red = low external capacity, green = low demand and purple = extreme scenario (all components for low prices together).

4.6. Wind power and the management of transmission capacities across borders

As previously shown, wind power is often the main contributor for causing situations with low prices in West-DK. One of the most important tools for managing large amounts of wind based overproduction is to export the electricity. Interconnection capacities are not always fully exploited. Therefore, a statistical view on the management of interconnection capacities in the hours of critically low prices is of interest, in order to gain an insight into whether there are circumstances that could be suspected of contributing to these market situations. Figure 4.19 gives a overview of the different import and export situations in hours with low prices, showing that on average, the two most expected market situations are 1) where West-DK exports to Norway while importing from Germany and 2) Where West-DK exports to all connected areas (both with a probability of 35.5 % to happen). This indicate that the most common scenario in terms of really low prices is one, where the spot price is either an internally created problem, or one partially caused by the North German power system of the EEX area - which is also reflected in the much higher system prices in NO1 and SE, respectively. With 5.4 % and 4.5 %, respectively, the third and fourth most expected power flow, in relation to low prices, is 4) where low prices occurs in NO1, resulting in a power flow going from NO1 and thus through West-DK for further export towards Germany and Sweden, and finally 3) where low prices in both Sweden, Germany and West-DK result in a power flow towards Norway.

Of the more interesting details in the figures below, is the difference in the utilization of the capacities when prices drop. From export situation (1) and (2) is seen that, in cases where wind (and likely cold too) causes the electrical spillover, making the export-option even much needed, the capacity *to* Sweden is averagely 47 % and 34 % of rated capacity (normally being averagely 67 %). This means, that the congestion management on capacities to Sweden (averagely) is an accomplice factor. Additionally, export-capacities to Norway (70 %) and Germany (70 %) are averagely lower when West-DK has a large export-need, than when the very same countries whishes to export (96 and 87 %, respectively). It is uncertain whether the reduced capacities during these periods of great export-need in West-DK, are to be blamed for on the Danish TSO or the TSOs of the neighboring systems.

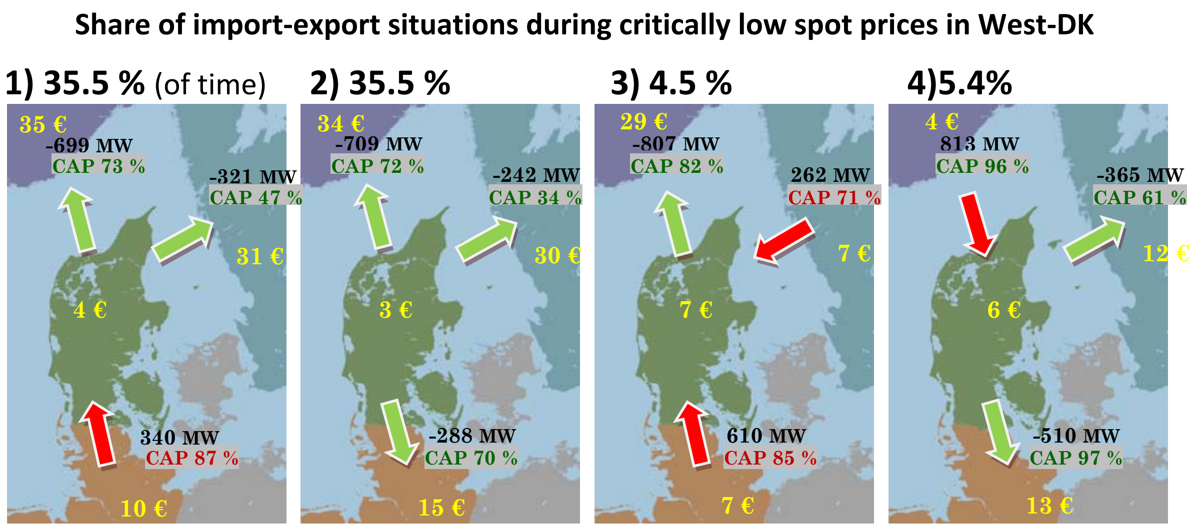


Figure 4.19, The four most common export situations when prices are critically low, showing that, in the observed 5-year period, most of the time, low prices are caused by the internal systems of West-DK or/and Northern Germany because of high wind penetration (see 1 and 2). But it also shows that sometimes, these prices are formed north of West-DK (melting water in the fall) (data source: Energinet.dk).

4.7. Summary

In this chapter the impact of wind power on the West-DK power system have been analyzed. It has been shown that although the electricity consumption is more or less constant throughout the year, the district heat-consumption falls during summer and rises during winter, and both the electricity and the heat consumption varies within the 24 hours of the day – like a camel with one hump in the morning and one around 'dinner time'. It has also been shown, that the productions of the electricity does not always fit the fluctuations of the demand, which is one of the reasons for critical low price hours. Other reasons for electrical overflow and critical low price hours are increased wind penetration, waning electricity demand, cold nights, rain, reduced interconnection capacity and constant central electricity production. We have seen, that most of the periods of low price hours are caused by internal factors such as increased wind, to which the central units does not seem to respond. The reason for this might be found in the difficulties with start-up and shut-down as well as the high cost of these procedures, whereas the duration of the low price periods are of relevance – the exact factors however remain unsure. Finally it has been shown, that there might be an unexploited possibility in cross-country export in this relation. A further analysis of this possibility would be of great interest, but lies outside the aim of this project, which in the fallowing chapters will focus on the model-based analysis of the consequences of the increasing wind penetration in the Danish energy system, which already causes critical low price hours in the Danish energy system of today.

Chapter 5.
Building the Mathematical Model

5.1. Overview

In order to get an insight to the consequences of increasing wind penetration on the Danish energy system, modelling the effect of a large increase in wind power capacity in a combined heat and power system similar to the Danish, is required. A unit commitment model is used to do this. Therefore, this chapter is dedicated the assumptions, considerations, theory and decisions which underlie the model, as well as the actual mathematical formulation of the model. In the fallowing section the two parts of modeling of the unit commitment problem will be presented.

5.2. Applied Theory and methods

In this project, solving the unit commitment problem can be divided into two parts: 1) the formulation of the unit commitment problem, 2) the optimization. The purpose of the first part is to a) present the basics of the mathematical projection and simplification of economic power systems, as well as b), to present the objective function and the constraints subjected to it for economic optimization. While the first part sometimes is referred to as the “easy” and fun part, the second part have traditionally been the one causing the troubles, often being highly complex, and thus requiring the finding and programming of suitable algorithms such as relaxations and heuristic search methods.

Luckily, there are different modeling tools and solvers available today (Ravn 2001), which to some extend can undertake the heavy part of the modeling task (more specifically: the programming part) by applying the necessary algorithmic tools. By having this today, some of the focus on the optimization modeling can be shifted towards the approximation and feasibility of the study, thereby keeping the focus of the outcome and not exclusively on the applied method.

As a result, the present project will avoid going into the more theoretical details of the applied method of the solving part, thus giving room for a more intuitive explanation as well as keeping focus on the overall aim of the project – the outcome.

5.2.1. The Unit Commitment Problem – an economic optimization problem

The problem of Unit Commitment is often connected to the economic optimization of large power systems that consist of a series of production units. It can basically be stated as the fallowing two key problems: 1) deciding which units to commit and subsequently 2) deciding how much quantity should be generated at each committed plant, in order to satisfy a number of demands with sufficient generation capacity (Petrov & Nicolaisen 1999). In a sense, the problem of 1) is a logical derivation from 2) which is often phrased as the Economic Dispatch Problem (ref a simple). Whereas the Dispatch Problem provides a solution to the current state of the network – how much available capacity there is at hand right now – the unit commitment problem provides a solution to the actual state of the system by scheduling the capacities available. Figure 5.1 represents these in a simplified way.

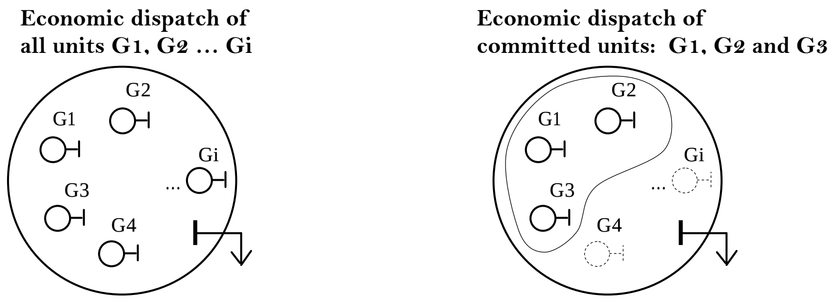


Figure 5.1, Theoretical sketch of the Economic Dispatch-problem (left), which is usually more simple to solve, and the same problem (right) with the units alternately committing and de-committing (Petrov & Nicolaisen 1999).

The choice, whether to do economic dispatch modeling, which is simple, or to use the more complex unit commitment model, involving a set of 0-1 restrictions (integers), becomes relevant the moment one considers to include boundaries and restrictions that are connected to the commitment of single units. Such being e.g. start-up costs, minimum capacity limits, ramp rates, spinning reserve etc. (Petrov & Nicoalisen 1999). By including these, the number of committed units suddenly may constrain the optimal solution of the system's economy, and another type solving is required.

One of the main reasons for choosing unit commitment modeling for the current project is the existence of such restrictions, and the expectation that restrictions are causing an undesirable quantity of constrained power generation in the real network. A condition which goes under the scope of the problems stated in this project.

Basically, the unit commitment problem is mathematically characterized by being constrained by a set of binary integer variables, which makes the optimization problem non-convex. The problem therefore must be solved through Mixed Integer Programming (MIP). The methods of MIP can be described as finding the best solution – linear or non-linear – of each possible 0–1 combination (being committed or de-committed). The applied solver algorithm performs a heuristic search for an optimal solution, and as long as the optimal solution is constrained by an integer variable (Solver 2009) new sub-problems of linear optimization are formed – often in a very large number. The generation of multiple sub problems is called branching (visualized as a tree consisting of nodes), and while searching for the optimal 0-1 combination throughout the modeled period, a cut of the solutions, that can be safely disregarded, is performed by the *branch and cut* algorithm. One of the biggest problems with MIP is that as the number of possible 0-1 combinations increases – so does the computational time and physical memory required for the task – exponentially (GAMS 2007). A further, and much more exhaustive, elaboration of the theoretical background of the solving of the unit commitment problem is found in Appendix 11.3.

5.2.2. GAMS/Cplex

The mathematical tools used in this project for this type of solving is a combination of the modeling language GAMS and the MIP solver Cplex, respectively. The programming software GAMS, which stands for General Algebraic Modeling System, is a tool specifically designed for optimization modeling (GAMS 2008). GAMS is known for letting the user having to concentrate solely on formulating the optimization problem, and not having to think much about the more 'technical' programming part, which normally comes along with complex mathematical routines as the unit commitment problem. This has been a great (and not least time saving) advantage, which have enabled a stronger focus on the output. The solver selected for this project is Cplex, due to its efficient MIP optimizing. For further descriptions on the advantages and functionalities of modeling in GAMS see Appendix 11.3.

5.2.3. Applied Economic theory and -model assumptions

In this section, the applied economic theory will be review in relation to the mathematical model. Furthermore, the necessary assumptions for the justification of the model as valid comparison for the real West-DK-market are presented.

Price formations

Price formations are in this context to be understood as the formations of prices on heat and electricity. In the model, as well as in the real system, price formations are an equilibrium between supply and demand (Nord Pool Spot), with the final price reflecting the production costs of heat and electricity of the cheapest marginal utility among the available producer types. As described earlier in Chapter 3 the market players on the production side in the Western Danish power- and heat system can roughly be split into the following four producer types:

1. Combined el. and heat producers with variable heat output (extraction units)
2. Combined el. and heat producers with fixed heat output (backpressure units)
3. Pure electricity producers, consisting of:
    a. Condensing units[17]
    b. Wind turbines
4. Heat producers, consisting of:
    a. Boilers

[17] Also counts as extraction units operating in condensing mode

b. Turbines by-passed extraction units

c. Heat pumps

What separates the characteristics of the Danish energy system, and thus the applied unit commitment model, from other power systems, is that a great part of the production comes from CHP units of (producer type 1 and 2). Now, as both 1 and 2 are CHP units, designed for satisfying both electricity and heat demands simultaneously (and in an economically optimized way) it is often the case, that CHP units only serves as marginal utility on either the heat- or electricity side, which can lead to a constraining of the corresponding ‘product’. In Figure 5.2 below is seen a theoretical description of the supply and demand relations of the economic electricity and heat systems, respectively. Since most of the production is produced by combined heat- and electricity generation, the price formation of the prices on heat and electricity, individually, are connected.

Cheap units play first. In a CHP-based system, prices on both the electricity and heat side (as shown in Figure 5.2) are formed by the variable costs of the cheapest available capacity satisfying the consumer’s marginal utility (Ravn 2001). Units of the supply curve with cheaper productions cost than the *marginal producer*, will automatically profit – a profit given marginal profit as seen in equation (5.1) below. Seen from a producer’s point of view, the optimal situation would always be to have the marginal revenue equal the marginal costs in order to maximize profit (Business Dictionary 2009) while a marginal profit different from zero reflects insufficient production capacity. The marginal producer on the other hand, will have balanced costs and thereby no marginal profit.

$$\textit{Marginal profit} \quad = \quad \textit{marginal revenue} \quad - \quad \textit{marginal production costs} \qquad (5.1)$$

Normally, producers will only choose to supply if the marginal costs are covered. For CHP units this is an ideal scenario, in the sense, that the only way CHP units can achieve such balanced marginal heat- and el. production costs, is when the production unit represents the cheapest marginal degree of freedom in both the electricity- and heat market at the same time, which is unlikely to happen – at least for more than one unit. As seen in the graphs of Figure 5.2 below, the parallel market situation sometimes is, that prices are determined by one type of CHP producer on the electricity market, and yet by another CHP unit in the heat market. It is then often the case, as too seen in Figure 5.2, that the marginal utility on the electricity market has lower electricity generation costs than the marginal unit in the. In the case where power is generated by the marginal CHP unit *on the heat market*, the generated power is considered constrained by the heat demand.

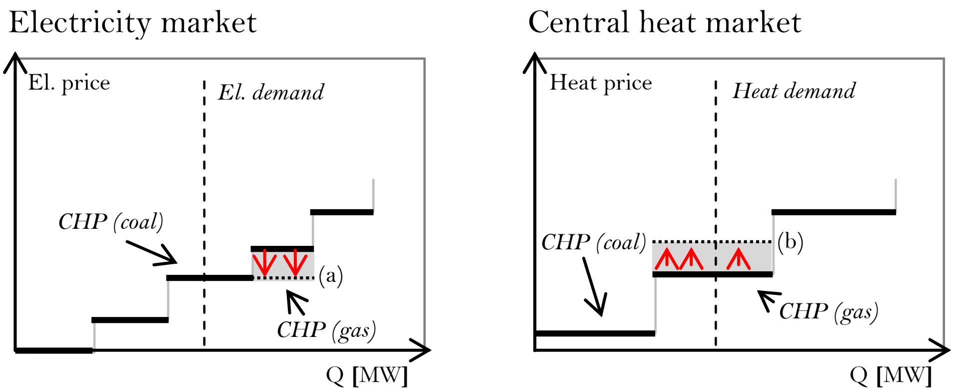


Figure 5.2, As seen through the model, electricity and heat prices are formed by each satisfying separately inelastic demands. Problem is, when the price-setting marginal CHP plant is cheaper on the electricity side (left) than the case for the local heat market (right), lost incomes on forced electricity (a) will be balanced by raising the marginal heat generation costs (b).

The results of CHP plants producing forced electricity, is that these constrained units no longer will influence the marginal quantities (Bregnbæk), as they no longer plays the part of cheapest marginal capacity. Moreover, the constrained power now contributes to a further suppressing of the CHP plants. Consequently, heat prices reflect how much extra fuel it will take for the heat system to produce one extra unit of heat. Under these conditions, the corresponding electricity can be considered as a waste- or bi-product of heat - and not the other way around as originally intended[18]. Whether this relation is a problem for the system economy as a whole is interesting to look further into, but fact is, that whenever cheaper marginal producers suppress locally heat-constrained CHP units from the Merit order (on the electricity-side), marginal heat-generation costs increases (in order to cover the "loss" on the el. market), ultimately resulting in high heat prices.

As shown in section 4.2.2, electricity and heat demand tend to follow the same patterns throughout a normal day which should decrease the problem caused by forced electricity production to some extent. But since wind penetration has increased dramatically over the previous decade, forced electricity has increased too. Central CHP plants have the option of varying the relative heat production – but only to the backpressure limit is reached, giving maximum 130 % heat for one unit electricity. Backpressure CHP plants give a fixed quantity of around 180 % per unit electricity which is a small advantage when heat is the scarce resource. Therefore, an improved ability to vary the production, and thus making the heat and electricity-interplay more flexible, may very well limit the price increasment due to the loss of income on the "over-supplied" product – whether this is electricity or heat.

[18] The original concept of distributing co-generated heat was to exploit the heat waste generated at thermal power plants, and use as a substitute for regular house heating and by this – increase the total efficiency.

Shadow prices

As mentioned earlier, the overall objective of optimization modeling is to minimize a system's total costs. However, the optimal value of the function in itself may contain very little information, while *changes* in this optimum can be given important interpretations.

To evaluate the costs of these changes, GAMS/Cplex automatically calculates what is known as the shadow prices. Shadow prices can in this connection be interpreted as the change in the objective value resulting from a one-unit increase in the constant of the specific constraint function. Most important is properly the shadow price of the electricity and heat demand satisfaction constraints, respectively. They indicate the specific change in the total-cost function $C(e^t_i, h^t_i)$ (known as the objective function) when raising the consumption levels by just one MWh, which can be interpreted as a heat- and electricity price, respectively. Shadow prices on constraints such as interconnectivity capacities, and upper and lower boundaries of productions units, indicates the value of changing these restrictions, and are therefore often used in this project for evaluating potential investments. Figure 5.3 shows a principle sketch of a two-dimensional situation where tree equilibrium points, one that is free (*a*) and two that are restricted (*b* and *c*), are generating shadow prices. The shadow price is zero at *a* and non-zero at *b* and *c*.

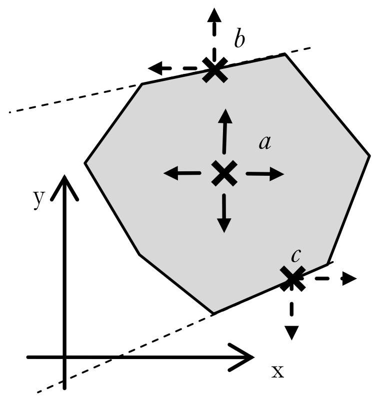


Figure 5.3, Three types of optimal solutions (equilibrium) found within a convex region "shaped" by linear constraints, can assume a shadow price that is either zero (a), positive or negative.

When the shadow price is positive *(b)*, it is an indication of extra costs connected with raising the upper bound constraint by one unit – and the opposite, if the restriction is a lower bound constraint (*c*). In the case of equilibrium *a*, it would make no (economic) sense to modify the constants of the constraining functions, as the shadow price at each linear constraint is calculated to zero.

As the optimal solution found is the equilibrium of a number of linear constraints, the shadow price represents the marginal *loss* or *gain*, of deviating one unit from this point. In the case of CHP units, every optimal operation point is a state of equilibrium between heat and el. production, respectively. In the case of extraction units, the operation points are often found positioned along one of the limits, representing either the upper or lower bound of electricity generation or the lower back pressure limit, forcing maximum heat out at a given electricity generation. The shadow price can therefore be used for indicating constrained heat- and electricity production.

In the case of electricity generation being constrained by the district heating demand, electricity prices are often lower that the price it would take to cover the marginal power generation costs. Therefore, the contribution for covering the loss from generating constrained power (at a lower price) will additionally come from an increasment of the marginal heat cost.

As the electricity prices are expected to drop due to an increased wind capacity of in the future, the heat production costs of the marginal utility will often be influenced by the unpleasant amount of "waste electricity". Figure 5.4 describes the two markets are connected, by showing heat price as a function of el. price for a system with an extraction unit (being the marginal heat producer)

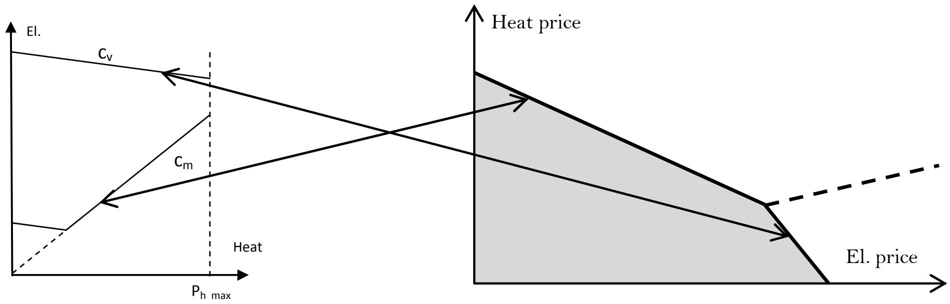


Figure 5.4, In a system with extraction unit as marginal producer, the relation between heat and el. price is given by an isoquant-like function, formed by the upper boiler limit as well as lower backpressure limit, respectively (Source: Balmorel brunch).

Economic system equivalence

In many ways, the characteristics of the unit commitment model differ from the real power and market system. First of all, performing an economic optimization of the whole economic system like in the model would in the real system correspond to the existence of just one producer with a complete monopoly[19]. At the real market, producers each decide which price is attractive producing under (Nord pool spot) and they add bidding conditions such as block offers. Nonetheless, the mathematical model in this project can be assumed equivalent to a system where, first of all, the market players at all times seek to maximize their profit, and second of all, that the market players are price-takers[20].

Unfortunately, a consequence of this is that the model, in its basic form, cannot include market power, and thus, that the total costs of the system will be underestimated to some extent (Bregnbæk 2008)

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[19] In the monopoly days, technical considerations of the different power plants were often taking into account with higher when scheduling operation hours.

[20] By price-takers are meant, that they can alter their rate of production and sales without significantly affecting the market price of their product, which would be the case when all players are infinitely small (Investopedia 2009).

The time factor is another main difference between the model and the real system. Where market players in the real system mostly plan operations one day ahead, the model plans and optimizes operations for the entire modeling period, which, as later shown, varies from a week to a month. Only a perfect foresight of future events would be the equivalent to this (Ravn 2001). For example, having knowledge of the exact wind production as far into the future as the modeled periods is a good example of a deviation between the model and the real system. Nevertheless, the model results can still be regarded as a reasonable approximation to the impacts of the 50 % wind power scenario. As long as the system characteristics are realistic, the deviations in price formations just described, will not be crucial for the approximation of these consequences.

5.2.4. Summary, applied theory and methods

So far, we have seen that the problem to be solved best can be solved by the unit commitment model since there are boundary restrictions connected to the commitment of single power plants, like minimum generation capacity and start-up considerations. The fundamental problem of unit commitment is figuring out an optimal combination of committed capacities; however, when optimizing this kind of problem, the feasible solution area of the root problem is no longer convex, which calls for Mixed Integer Programming (MIP). MIP is considered among the more complex problems to optimize, given the binary constraints. Luckily, today there are a number of available solvers to undertake this rather heavy part, which means, that this project can focus more solely on the modeling as an application study rather than a method study. The principles behind the unit commitment problem have been shown, and the arguments for choosing the GAMS language and the Cplex solver have been stated.

Furthermore it has been shown, that the formation of the heat- and electricity prices, is a result of the marginal costs of the different types of plants. In the case of CHP plants, the marginal costs of heat and electricity are mutually dependent by the formation formations in each market. Since a great part of the production comes from power units producing both heat and electricity, the heat price will usually increase as the electricity price decreases, and vice versa.

It has also been shown that the prices are calculated from what can be interpreted as shadow prices, and finally it has been argued, that the model is equivalent to a market system consisting of price-takers, which means that all player are seeking to maximize their profit at all times, by which market power is neglected, and that – despite the different deviations – the model can approximate the impacts of increasing wind capacity in a market area like West-DK.

5.3. Model formulation

This section reviews the formulation of the mathematical model, from defining its "geographical" areas and boundaries to modeling the characteristics of the different production units. The basis of this is the proposals regarding the extensions of the wind capacities in West-DK stated by Energinet.dk (outlined in Chapter 3).

It is in this connection relevant to remind that the scope was to build a model with some of the same characteristics as the Danish energy system, which can be used to help clarify how increased wind penetration will affect the system, as well as how different tools for increased production flexibility might reduce some of the documented problems – not to create a perfect approximation of the West Danish heat- and power system. However, a great part of the system characteristics, when it comes to dimensioning the production capacities as well as the profiles for wind production and the heat- and electricity demands, are either heavily inspired by, or have directly been taken from, data of the Western energy system.

5.3.1. Power system simplifications

One of the key problems of building an optimization model is to find the right balance between, on the one side, creating a simple and efficient model that still meets the objective of the model and, on the other side, building a compute-heavy, high detailed model with great similarities to a real system. Finding the right balance often takes an experienced model programmer, but can also be achieved by starting out with a simple constellation and then, step by step, adding more elements until the final result – although this can be a rather time-consuming process. Figure 5.5 shows the final geographical system.

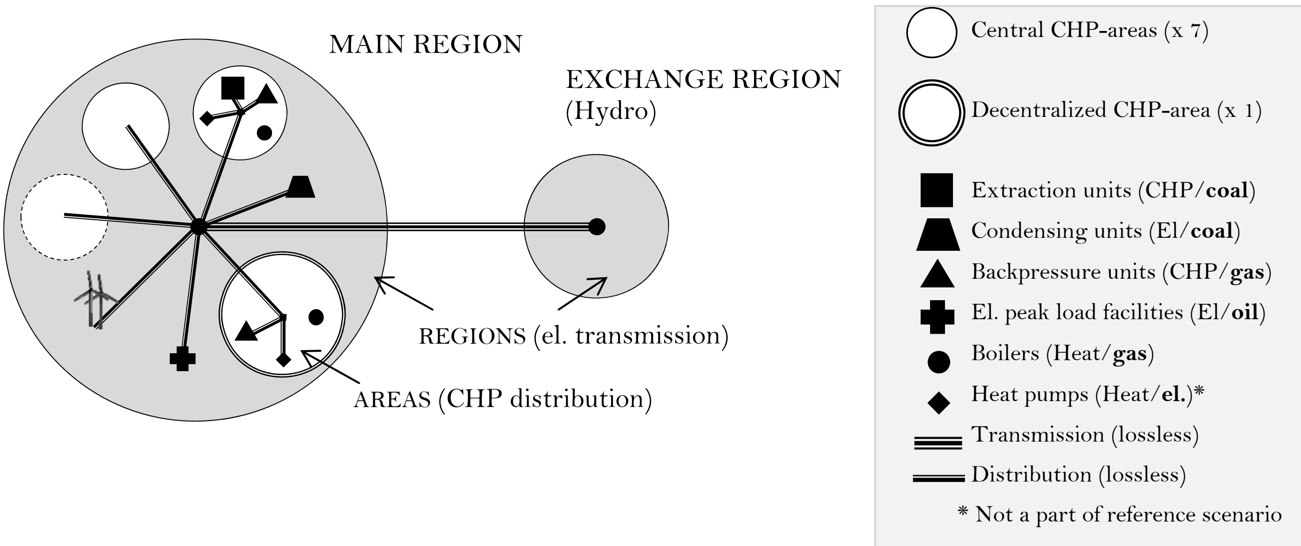


Figure 5.5, An illustrative, graphical overview of the fictional heat and power system used for approximation of the impacts from increasing wind power as well as inclusion of heat pumps and bypass.

Transmission regions and distribution areas

As seen above the geographical system has been limited to consist of just two regions with the exchange region approximated as mainly the Norwegian hydro system. By doing this, intention is to imitate the storage mechanism of today's wind-hydro interplay in the Nordic area. An exchange area, similar to the North German transmission system, has not been included in the model. The reason for this is: Because the North German system, like West-DK, is characterized by a combination of thermal production and a great amount of wind capacity, the expectation is that a interconnection under these conditions not will play a “buying role” in the same scale as the countries to the north will, since frequently having to deal with an additional electrical oversupply from wind power (as shown in Chapter 3).

The main region, shown to the left (Figure 5.5), is the approximation of a heat- and el. system which is basically similar to West-DK. This part has been designed with a number of simplifications too. On the electrical side, one of the greatest simplifications is the complete disregard of inner capacity constraints (lossless transmission), in which the whole region has been “electrically merged” – assuming infinitely strong grid to allow an unconstrained load flow. The greatest disadvantage of this, compared to the real transmission systems, is that productions, which in the real system would be restrained by inner capacity limits, can be perfectly managed in the model. The result is probably, that more electricity will be transmitted in the model than in the real systems. On the other hand this lack of restrictions can be approached by setting a lower exchange capacity. The heat supply has been divided into eight distribution areas where seven of them are represented by a large extraction unit each. Together the seven areas represent the central-heat consumption, and the eighth distribution area represents all the small de-centralized CHP areas merged together as a large producer and consumer. The reason why the model consists of a combination of several central areas and just one single de-centralized area, is that the lower-bounds of large extraction units alone, may be likely to affect the optimal operating schedule, whereas smaller backpressure units alone are too small to have an influence. This goes for the economics as well, where for example the start-up of a single central unit is far more costly than the start-up of a small plant, thereby making the start-up of the smaller plant seem irrelevant in relation to the unit-commitment problem.

As seen in the figure, all central distribution areas consists of one extraction unit, boilers, and backpressure units as well as heat-pumps and bypass-possibilities (in the scenarios concerning those). The de-centralized distribution area includes same producer types except, of course, central extraction units. Outside of the distribution areas are seen units generating only electricity, represented by wind turbines and condensing units, respectively.

5.3.2. System scenarios

C.f. the stated objectives of this project, a number of different scenarios will be applied to the model, given by a few modifications. The different system scenarios are:

1) **Reference scenario:** System is modeled according to Figure 5.5 but without heat pumps and optional by-pass operation (BPO) of high pressure turbines. The main purpose of this set-up is first of all to examine the influence of varying wind penetration through different seasons, without implementing instruments for increased production flexibility.

2) **Bypass scenario:** System is "physically" modeled as in 1) but this time, all extraction units have optional BPO. The idea behind this scenario is to measure the impacts of optional switching from co-generated heat to pure heat - under the influence of varying wind and consumption data.

3) **Heat-pump scenario:** System is modeled as shown in Figure 5.5 with electrical heat pumps and no BPO. The idea of modeling the third scenario is basically the same as in 2).

Despite of the futures aspect of modeling of the 50 % wind scenario, all other physical and economic parameters are held constant in order to examine the applied effects isolated. In the fallowing section the mathematical formulation of the modeled scenarios is reviewed.

5.3.3. Formulation of the Unit Commitment problem

As mentioned earlier (section 5.2), the aim of the stated unit commitment problem is to minimize the objective function C of total costs:

In the objective function (5.2):

$$C(i,t) = \sum_{t=1}^{T}\sum_{i=1}^{N}\left(mc_i \cdot P_i^t + mc_{cbp} \cdot P_{cbp,i}^t + mc_{cb} \cdot P_{cb,i}^t + sc_i \cdot st_i^t\right) + \sum_{t=1}^{T}\left(mc_x \cdot P_x^{\,t} + mc_{dcb} \cdot P_{dcb}^t\right) \tag{5.2}$$

P^t_i is the fuel input of a total 11 units indicated by index i. These 11 units are then allocated on seven extraction units (1-7), two condensing units (8-9), all the peak-load utilities (10) and finally, all the de-centralized backpressure units (11). Additionally, mc_i is the corresponding marginal costs of unit i. Furthermore, $P^t_{cb,i}$ and P^t_{dcb} correspond to the boiler capacities of the central- and de-centralized areas, respectively, as $P^t_{cbp,i}$ represents the backpressure CHP units in each central area. The variable st^t_i is an integer and start-up indicator, assuming the values (0;1) and thus multiplied with start-up costs sc^t_i of the concrete unit.

As seen, the costs functions $C_i(e,h)$ is exactly proportional to the fuel combustion and hence equivalent to the linear expression:

$$C_i(e,h) = mc_i \cdot P_i(e,h) \qquad .(5.2)$$

Applied constraints

The objective function is subjected to the following constraints:

Demand constraints:

$$\sum_{i=1}^{N}\left(P_{el,i}^{t}+P_{el\_bp,i}^{t}\right)+P_{W}^{t}-P_{12}^{t}=P_{D,el}^{t} \qquad (5.3)$$

The hourly satisfaction of the electricity demand is given by equation $\sum_{i=1}^{N}\left(P_{el,i}^{t}+P_{el\_bp,i}^{t}\right)+P_{W}^{t}-P_{12}^{t}=P_{D,el}^{t}$ (5.3(5.4) above. $P^t_{el,i}$ is the power generation at the 11 units just described and additionally $P^t_{el\_bp,i}$ are the power generation from back pressure units in the seven central areas. P^t_W is the production from wind and P^t_{12} the exchanged power, where $P^t_{12} > 0$ means net-export in the particular hour. On the heat side it basically works the same way, except that the satisfaction of the heat demand is done separately on a distribution-area level, as shown in equation (5.5) and (5.6).

Central CHP areas (i = 1-7): $P_{h,i}^{t}+P_{cb,i}^{t}+P_{h\_bp,i}^{t}\geq P_{D,h,i}^{t}$ (5.4)

Decentralized CHP area (i = 11): $P_{h,i}^{t}+P_{dcb,i}^{t}\geq P_{D,h,i}^{t}$ (5.5)

As seen, the heat demands are stated as inequalities so that heat production will not have any upper restrictions in case of scarcity of electricity, and hence have optional releasing heat as waste.

Constraint (5.7) below ensures that consumption in the exchange area is satisfied by only one type generation P^t_x plus the net-import ($P^t_{12} > 0$). In addition, equation (5.8) and (5.9) ensures that the exchange capacity is not exceeded in both ways.

$$P_{x}^{t}+P_{12}^{t}\geq P_{D,x}^{t} \qquad (5.6)$$

$$P_{12}^{t}\leq P_{12,\max} \qquad (5.7)$$

$$P_{12}^{t}\geq -P_{12,\max} \qquad (5.8)$$

Binary constraints:

$$x_{i}^{t}=[0;1] \qquad (5.9)$$

$$st_{i}^{t}\geq x_{i}^{t}-x_{i}^{t-1} \quad , \; st_{i}^{t}=\begin{cases}1 & if \quad 0\ 1\\ 0 & if\ else\end{cases} \qquad (5.10)$$

In (5.10) the binary variable x^t_i is defined as an integer that can only assume the values (0;1) and thus, it is the variable that defines the optimization problem as unit commitment. Equation (5.11) is not so much a constraint as a calculation of the start-up indicator st^t_i of unit i. The calculated value st^t_i is in GAMS defined as a positive integer which results in the two outcomes shown above, where 0 1 respectively symbolizes previous and current state of x^t_i.

Extraction units:

$$P_i^t = \frac{P_{el,i}^t}{\eta_{el,i}} + \frac{c_{v,i}}{\eta_{el,i}} \cdot P_{h,i}^t \qquad (5.12)$$

The fuel constraint $P_i^t = \frac{P_{el,i}^t}{\eta_{el,i}} + \frac{c_{v,i}}{\eta_{el,i}} \cdot P_{h,i}^t$ ((5.12) calculates the fuel consumption (converted to chemical energy) as a function of electricity and heat generation. Recalling Figure 3.8, the relation between electricity and heat is expressed by the iso-fuel lines with the flat slope value c_v, which represents the marginal loss of electricity per extracted unit heat from the turbine. $\eta_{el,i}$ is the electrical net efficiency of unit *i*.

Following down along the iso-fuel lines, eventually they stop at the backpressure limit expressed by the c_m-constraint $P_{el,i}^t \geq c_{m,i} \cdot P_{h,i}^t$ (5.11(5.13):

$$P_{el,i}^t \geq c_{m,i} \cdot P_{h,i}^t \qquad (5.11)$$

The maximum and minimum electrical output is expressed by constraints (5.14) and (5.15) below.

$$P_{el,i}^t \geq -c_{v,i} \cdot P_{h,i}^t + P_{\min,i} \cdot x_i^t \quad , x_i^t \in [0;1] \qquad (5.12)$$

$$P_{el,i}^t \leq -c_{v,i} \cdot P_{h,i}^t + P_{\max,i} \cdot x_i^t \quad , x_i^t \in [0;1] \qquad (5.13)$$

The maximum heat output, as restricted by the capacity of the heat exchanger, is given by equation (5.16):

$$P_{h,i}^t \leq P_{h,\max,i} \qquad (5.14)$$

The extraction units are not only constrained by upper and lower bounds of boiler and heat exchanger, but also by the time-differential aspect of the operation, referring to the hourly gradient of the boiler output. This restriction is often known as the ramp-rate condition, here given by equation $P_i^t - P_i^{t-1} \leq UR_i \cdot x_i^{t-1} + P_{st,i} \cdot st_i^t$ (5.15(5.17) below.

$$P_i^t - P_i^{t-1} \leq UR_i \cdot x_i^{t-1} + P_{st,i} \cdot st_i^t \qquad (5.15)$$

UC combination:	x^{t-1}_i	st^t_i	*Resulting up-ramp con.:*
If 1 1	1	0	$P^t_i - P^t_i \leq UR_i$
If 0 1	0	1	$P^t_i - 0 \leq P_{st,i}$
If 1 0	1	0	$0 - P^t_i \leq UR_i$
If 0 0	0	0	$0 \leq 0$

Table 5.1, Different up-ramp conditions in relation to the specific operation mode. Reason is, that the ramp conditions must always be satisfied during each of the four combinations of 'before-now' commitment.

In this constraint the difference between the current and previous fuel consumption is systematically measured for compliance with the two ramp-rate restrictions. The challenge in this connection however, is to consider the all four before-now states of each unit i individually, more specifically being: in operation (1-1), starting up (0-1), shutting down (1-0), and de-committed (0-0). The solution was to use both binary variables $x^{t-1}{}_i$ and $st^i{}_i$. Table 5.1 shows the different equation-outcomes of the four combinations. Here, UR_i and $P_{st,i}$ are the up-ramp limits during constant operation (1-1) and maximum start-up power (0-1), respectively. The ramp-rate constraints concern the up-ramp situation and include condensing units as well. Other units however, such as backpressure-, peak-load- and boiler utilities are chosen not to be restricted by these because they consist of a larger number of smaller units merged as one.

Extraction units with by-pass operation options:

Modeling units with optional BPO-mode requires a relaxation of the lower bound constraints (5.13) and (5.14), respectively, in order to stop generating power while still operating along the heat axis as an either/or restriction. The constraints that will be affected by this adjustment are rewritten in the following.

First thing to do is to introduce a new binary variable $b^t{}_i$ (5.18) that decides whether to switch BPO on or off.

$$b_i^t = [0;1] \qquad \text{, where } b_i^t = \begin{cases} 1 & if\ BPO = on \\ 0 & if\ BPO = off \end{cases} \tag{5.16}$$

Since the fuel constraint only works with el. generation turned on, eq.(5.19) relaxes this condition by subtracting a very large number M in case of BPO switched on. This is followed by a new fuel constraint (5.20) that, in reverse, is relaxed with BPO turned off.

$$P_i^t \geq \frac{P_{el,i}^t}{\eta_{el,i}} + \frac{c_v}{\eta_{el,i}} \cdot P_{h,i}^t - M \cdot b_i^t \tag{5.17}$$

$$P_i^t \geq \frac{P_{h,i}^t}{\eta_{bp}} - M \cdot (1 - b_i^t) \tag{5.18}$$

Next thing is to rewrite the minimum el. output constraint (5.14) for relaxation in case of BPO, as done in (5.21)

$$P_{el,i}^t \geq -c_{v,i} \cdot P_{h,i}^t + P_{\min,i} \cdot x_i^t - M \cdot b_i^t \tag{5.19}$$

And additionally, the backpressure constraint (5.13) is disregarded through the fallowing equation (5.22):

$$P_{el,i}^t \geq c_{m,i} \cdot P_{h,i}^t - M \cdot b_i^t \tag{5.20}$$

Now, ensuring that the el. generation is zero, constraint (5.23) is added:

$$P_{el,i}^t \leq M \cdot (1 - b_i^t) \tag{5.21}$$

Under normal operation, the minimum el. generation constraint indirectly secures that the boiler minimum is not deceeded. With the extraction units only producing heat when switched to BPO, the minimum limit then have to be expressed as a function of only heat, as seen in equation (5.24). Dividing $P_{min,i}$ by the electrical net-efficiency and multiplying with the efficiency of the heat exchanger, converts the lower bound (of the boiler) from electricity to heat.

$$P_{h,i}^{t} \geq P_{\min,i} \frac{\eta_{CHP,i}}{\eta_{el,i}} \cdot x_i^t - M \cdot (1 - b_i^t) \qquad (5.22)$$

Backpressure units:

For backpressure units, fuel consumption as a function of electricity and heat is given by equation (5.25), by which the relation between el. and heat is fixed through the backpressure value $c_{m,i}$ as seen in equation (5.26).

$$P_i^t = \left(P_{el,i}^t + P_{h,i}^t\right) \cdot \frac{1}{\eta_{i,cph}} \qquad (5.23)$$

$$P_{el,i}^t = c_{m,i} \cdot P_{h,i}^t \qquad (5.24)$$

Wind power:

In order to secure the system balance against critical electrical spillover in hours with extremely large wind penetration, wind production will be given a degree of freedom in the form of optional down-regulation, as seen in Figure 5.6. The wind profile then will serve as the maximum capacity rather than actual output, which is also expressed by the inequality symbol of the constraint seen in equation (5.27).

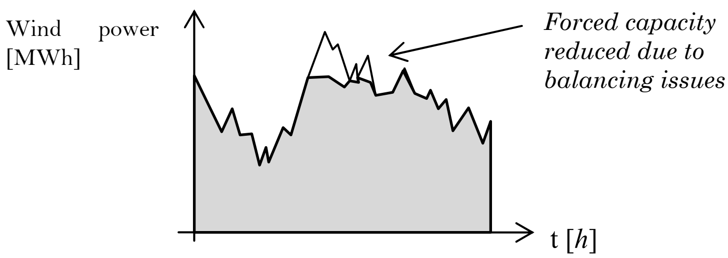


Figure 5.6, The model have optional down regulation of the wind power.

$$P_w^t \leq P_{w,\max}^t \qquad (5.25)$$

Spinning reserve:

As the TSO requires minimum three central units committed at all time (for rapid frequency control), the constraint in equation (5.28) ensures this.

$$\sum_{i=1}^{9} x_i^t \geq 3 \tag{5.26}$$

The heat-pump scenario:

Adjusting to the heat-pump scenario only requires changes of the demand satisfaction constraints. Since electricity works as “fuel” when producing heat on heat-pump, $P^t_{el,hp}$ and $P^t_{el,hp,i}$ is inserted on the consumption side of equation (5.5) and (5.6) as seen in equation (5.29). The electricity consumption is thus applied to the central and de-centralized heat-demand constraints (5.30) and (5.31), multiplied with the COP factor η_{hp} of the electricity-to-heat conversion.

$$\sum_{i=1}^{N}\left(P^t_{el,i} + P^t_{el\_bp,i}\right) + P^t_W - P^t_{12} = P^t_{D,el} + \sum_{i=1}^{N} P^t_{el,hp,i} + P^t_{el,hp} \tag{5.27}$$

$$P^t_{h,i} + P^t_{cb,i} + P^t_{h\_bp,i} + \eta_{hp} \cdot P^t_{el,hp,i} \geq P^t_{D,h,i} \tag{5.28}$$

$$P^t_{h,i} + P^t_{dcb} + \eta_{hp} \cdot P^t_{el,hp} \geq P^t_{D,h,dc} \tag{5.29}$$

5.4. Generation of input data

One of the challenges of optimizing the UC problem is to feed the model with proper data. In this project, all data has one way or the other been taken from the West Danish power system, whether it is for power units or consumption profiles.

5.4.1. Data for power units

This section presents the background of the data applied to the thermal units of the UC model. The characteristics of the central power plants modeled in this project, are more or less taken from the nine largest central power plants (production wise) operating in today’s West-DK system. In Table 5.2 is seen, how the real data have been converted into the data applied to the model. It is seen that the heat-production capacity of the two last units: NJV2 and ENV3, are virtually non-existent. They have therefore been assumed zero and will be regarded as purely condensing units.

		Ratet capacities		commissioned	Primary fuel	Source		Capacities for UC model	
Name	**Block**	**El. [MW]**	**Heat [MW]**	**year**	**Heat [MW]**	**name**	**unit G(*i*)**	**El. [MW]**	**Heat [MW]**
Nordjyllandsværket	NJV 3	410	420	1997	*Coal*	*Vattenfall*	G1	400	450
Studstrupsværket	SSV 3	350	455	1985	*Coal*	*DONG Energy*	G2	350	450
Studstrupsværket	SSV 4	350	455	1985	*Coal*	*DONG Energy*	G3	350	450
Esbjergværket	ESV3	378	460	1992	*Coal*	*DONG Energy*	G4	400	500
Fynsværket	FYV3	235	340	1974	*Coal*	*Vattenfall*	G5	250	350
Fynsværket	FYV7	362	475	1991	*Coal*	*Vattenfall*	G6	400	475
Skærbækværket	SKV3	392	444	1997	*Coal*	*DONG Energy*	G7	400	450
Nordjyllandsværket	NJV 2	225	42	1977	*Coal*	*Vattenfall*	G8	250	~ 0
Enstedsværket	ENV3	626	85	1979	*Coal*	*DONG Energy*	G9	650	~ 0
	Total	**3328**	**3176**	-	-	-	-	**3450**	**3125**

Table 5.2, Using real data from central utilities in West-DK for use in model. The capacities are rounded (data source: DONG energy 2009, Vattenfall 2009).

Calculation of marginal production costs

The source data behind the calculation of the marginal prices are listed in Table 5.3. The currency is stated in Dkk because this was the currency used when the results were processed. Final results will be presented in Euros[21].

Source data:

Energy prices		Callorific values	CO2 costs			currency:	O&M per MWh,fuel	
Coal price	**Gas price**	**Coal**	**CO2 price**	**Coal**	**Gas**	**Dkk / €**	**Central**	**Decentralized**
450 [Dkk/ton]	**45** [Dkk/GJ]	**24,40** [GJ/ton]	**150** [Dkk/ton]	**0,34** [t CO2/MWh]	**0,2** [t CO2/MWh]	**7,56** [Dkk/€]	**13,6** [Dkk/MWh]	**19** [Dkk/MWh]

Table 5.3, Key numbers for calculating marginal gen. costs. (Data sources: Danish Energy Authorities 2005) * Final value assumed

The marginal costs of thermal power facilities have traditionally been highly sensitive to changes in fuel prices, and since the introduction of CO2 quotes, sensitive to them as well. The graph to the left of Figure 5.7a shows how prices on coal (which is the main energy source for el. generation in the Danish power system), have increased dramatically the resent years, peaking in July 2008, and then dropping to a much lower level by the end of the same year. It could seem as if a more stable coal price have recently emerged from the fog of various economic speculations and capacity issues that have characterized recent year's overheated economic system. From this economic point of view, a coal price of 60 € is selected as the constant price in this project. In Figure 5.7b to the right is seen how the marginal generation costs of backpressure units are sensitive towards changes in the Natural Gas price, and central units being sensitive to the CO2 price (due to a high emission factor).

Coal price development

[21] 100 DKK = 765 Euro

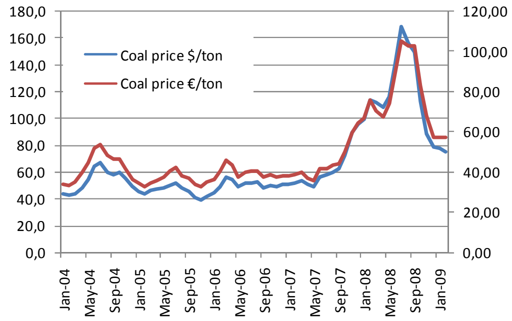


Figure 5.7a, Development in coal prices over a five year period (Data source: Energistyrelsen).

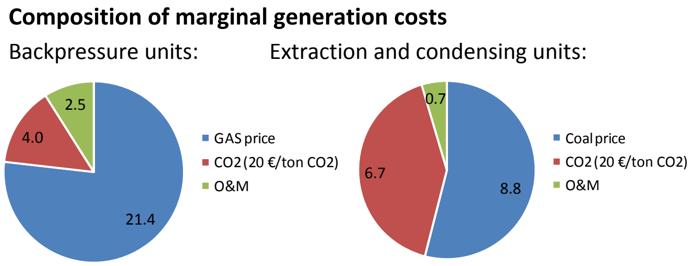


Figure 5.7b, comparison of the marginal generation costs of decentralized (left) and central (right) units.

The same is the case when it comes to the Natural gas-prices. An example of this is the fact that from August 2008 to January 2009 prices dropped a factor of two from an historic peak level of 0.57 €/m^3 down to 0.28 €/m^3. Prices on fuels and raw materials are in general hard to count on when analyzing over a large timeframe.

Marginal costs of central units:

$$MC = fuel\ costs + CO_2\ costs + O\&M =$$

$$\frac{450 \cdot 3.6}{24.4} + 150 \cdot 0.34 + 13.6 \cdot \eta_{el} \approx 125 \quad [Dkk\ /\ MWh\ ] \approx 16.5 \quad [€\ /\ MWh\ ] \tag{5.30}$$

The O&M costs are corrected for fuel consumption via the el. net efficiency. Marginal costs are also applied to condensing units.

Marginal costs of de-centralized units:

$$45 \cdot 3.6 + 150 \cdot 0.20 + 37 \cdot \eta_{el} \approx 210 \quad [Dkk / MWh] \approx 28 \quad [€ / MWh] \tag{5.31}$$

Table 5.4 shows some additional marginal costs per unit fuel used in the model. From a model point of view, it made sense to link the marginal generation costs of peak load utilities (oil) to the costs of backpressure units (gas)[22], as well as to appoint the same marginal costs to boilers, since a high detail-level on the prices on more expensive units is of less interest to the current objective. The marginal costs of wind power is actually around 9 €/MWh (Danish Energy Authorities 2005), which mainly is due to inner wear on machine components. But as wind power generally receives a public contribution of 33 € per produced MWh wind the energy is practically offered at zero-price, thereby ensuring that the total wind capacity is supplied to the market.

[22] Gas prices are traditionally linked to oil prices (Winje 2007/2008a,b,c).

Peak load	Boilers	Heat pumps	Heat pumps
210 [Dkk/MWh]	**210** [Dkk/MWh]	**37.8** [Dkk/MWh]	**0** (68) [Dkk/MWh]
(~28 €)	(~28 €)	(~5 €)	(~9 €)

Table 5.4, costs per-unit consumed fuel applied to different utilities in the model (data source: Energistyrelsen).

Thermal utility properties

Table 5.5 below presents the final technical and economic data of thermal units used in the model. The technical data is taken from the technology catalogue (Danish Energy Authorities 2005) and thus reflects the power unit's properties as if they were constructed tomorrow. Therefore they might be more efficient than those in the West-DK system.

		Heat output limits			Up-ramp limits		Efficencies				COSTS	
unit (i)	type	Pel,min [MW]	Pel,max [MW]	Max heat [MW]	Pst [MW]	RR [MW]	ηel	η_CHP	cv [-e/h]	cm [e/h]	marginal [€/MWh]	start-up [€]
G1	*Extraction (Coal)*	80	400	450	700	500	0,47	0,92	0,15	0,75	16,53	1323
G2	*Extraction (Coal)*	70	350	450	700	500	0,47	0,92	0,15	0,75	16,53	1323
G3	*Extraction (Coal)*	70	350	450	700	500	0,47	0,92	0,15	0,75	16,53	1323
G4	*Extraction (Coal)*	80	400	500	700	500	0,47	0,92	0,15	0,75	16,53	1323
G5	*Extraction (Coal)*	50	250	350	550	500	0,47	0,92	0,15	0,75	16,53	1323
G6	*Extraction (Coal)*	80	400	475	700	500	0,47	0,92	0,15	0,75	16,53	1323
G7	*Extraction (Coal)*	80	400	450	700	500	0,47	0,92	0,15	0,75	16,53	1323
G8	*Condensing (Coal)*	50	250	-	1000	500	0,5	-	-	-	16,53	1323
G9	*Condensing (Coal)*	130	650	-	1000	500	0,5	-	-	-	16,53	1323
G10	*Peak-load (Oil)*	0	1000	-	*no limit*	*no limit*	0,42	-	-	-	27,78	0
G11	*Backpressure (Gas)*	0	*no limit*	*no limit*	*no limit*	*no limit*	-	0,9	-	0,55	27,78	0
Others												
Boiler dc	*Heat (Gas)*	-	-	*no limit*	*no limit*	*no limit*	-	0,9	-	-	27,78	-
Boiler c (*i*)	*Heat (Gas)*	-	-	*no limit*	*no limit*	*no limit*	-	0,9	-	-	27,78	-
CHP c (*i*)	*Backpressure (Gas)*	-	*no limit*	*no limit*	4000	*no limit*	0,9	0,9	-	0,55	27,78	-

Table 5.5, Technical and economic properties of the thermal utility types applied to the model. In terms of boilers, the ηCHP value works as pure heat efficiencies (Data source: Danish Energy Authorities 2005, DONG Energy 2009, Vattenfall 2009).

As seen, the minimum bound for electricity production $P_{el,min}$ is assumed 20 % of the maximum rated capacity $P_{el,max}$ because of missing information on this. Reason for this might be, that the minimum boiler capacity often is an unspecified range, that traditionally never have being given much attention from power-plant producers and -operators – probably because they never imagined the plants operating at such a low level[23] for very long. The assumed 20 % is a reasonable approximation (Boldt), and the lower efficiencies, which will probably be around this low output level, is not being corrected for in the model. All non-central units have basically been assigned no upper- and lower capacity limits, which on a model basis is practical in relation to avoiding infeasibilities when solving.

[23] This is also the case in various technology sheets from el. power facilities which often just describe operation within the load range 50 - 100 %

The start-up costs is another rather unknown factor (this goes for generation costs in general) mainly connected long power-up periods – especially in case of cold-starts. It is thus assumed 1323 €/startup (10,000 Dkk) for central units in order for them to have marginal influence on the commitment problem, and zero costs for the remaining units. For simplifications, no economic distinguishes have been made between cold and hot start-ups.

Until now, the generation costs of the specific utilities have been calculated in relation to fuel consumption and not for el. and heat individually. In this connection, Table 5.6 shows the marginal productions of el. and heat when assuming that the bi-product is valueless. The third column is marginal CHP-generation costs in a balanced market.

	el (condensing)	Heat (el.price = 0)	co-generation (balanced price)
unit (*i*)	[€/MWh]	[€/MWh]	[€/MWh]
G1	35,17	31,19	17,97
G2	35,17	31,19	17,97
G3	35,17	31,19	17,97
G4	35,17	31,19	17,97
G5	35,17	31,19	17,97
G6	35,17	31,19	17,97
G7	35,17	31,19	17,97
G8	33,06	-	-
G9	33,06	-	-
G10	66,14	-	-
G11	86,81	47,90	30,87
Others			
Boiler dc	-	30,87	-
Boiler c (*i*)	-	30,87	-
CHP c (*i*)	86,81	47,90	30,87

Table 5.6, Generation costs of el., heat and CHP production individually. In the case of backpressure units (G11), which have fixed heat-el. ratio, condensing refers to el. production with zero heat price (data source: Energistyrelsen).

From Table 5.6 is seen, that the central extraction units by far are the most economic efficient when it comes to CHP production. It is also seen that boilers are more competitive at heat production when el. prices is zero, and vice versa, and that condensing units are best at electricity production when heat price is zero. Although all three production scenarios rarely occur, the table however gives a good illustration of the economy of thermal units in the modeled system.

Heat pumps

The selected capacities for central and decentralized production areas are accessed on basis of the results of a model sequence with infinite heat pumps capacity. As illustrated in Figure 5.8 , a duration curve on the production has been processed and then, the suitable capacities found where the curves break and start to flatten. The result of this method is the installation of a total heat pump capacity of 350 MW in the central heat areas, while 550 MW in decentralized areas, which indicates a larger (economic) heat pump-potential in decentralized area.

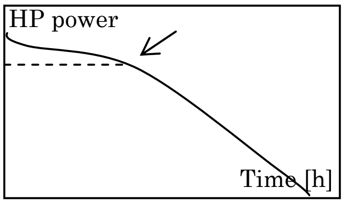


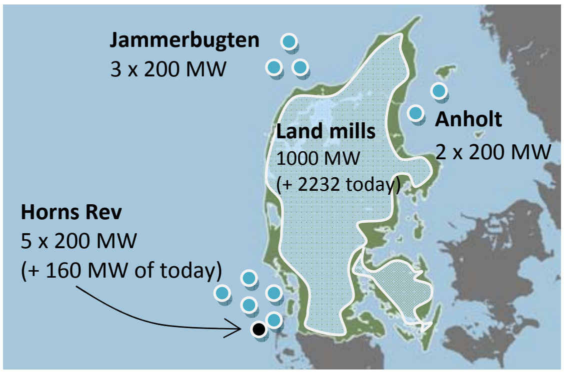
Figure 5.8, The principle behind estimating the potential amount of heat pump capacity, is by ob-serving the duration curve of the production from a system with infinite heat pump capacity.

5.4.2. Creating wind profiles

In connection with modeling a system with increased wind penetration c.f. the goal of achieving 50 % wind production by 2025, one of the greater challenges has been to figure out a proper way to generate a realistic wind profile. It has previously been shown that the intention of the Danish TSO, according to their system-plan report of 2007[24], was to place the extra wind capacity as follows:

	2008	2025
Land mills	2232	3232
Offshore:	160	2160
Horns Rev	160	1160
Jammerbugten	0	600
Anholt	0	400
total	**2392**	**5392**

Table 5.7, An overview of the intended location of wind-capacity expansion that forms the framework of modeled scenarios (data source: Energinet.dk 2007).



The current wind capacity of today's West-DK system can be divided into two types of productions: one coming from offshore wind farms and one from land mills, respectively. While land mill production is characterized by the turbines being geographically spread over the region, the production from offshore wind farms is more extreme – on terms of fluctuations - because of the turbines being concentrated on smaller areas. The difference between their production profiles is seen in Figure 5.9 below:

[24] Energinet.dk have afterwards produced a more detailed plan of where to place the capacity, which includes spreading the wind farms further out than in the suggestion used as framework in this project.

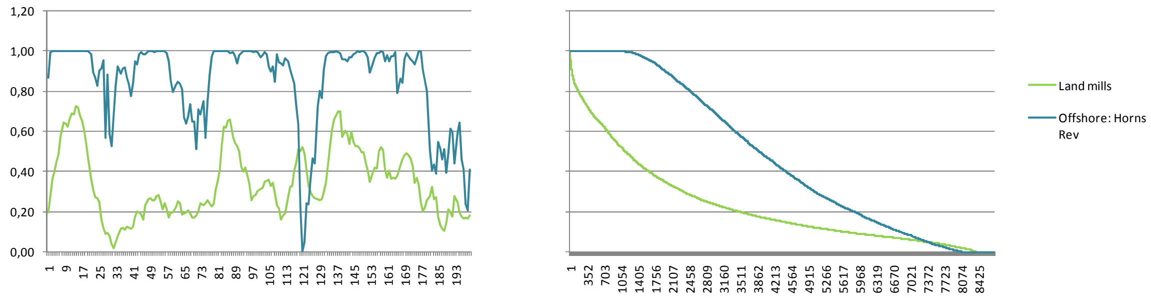


Figure 5.9, Left: a January-sample of production profiles from Offshore (160 MW at Horns Rev) and land mills (2232 MW onshore), respectively. Right: comparison of the two production type's individual duration over a whole year (data source: Ea Energianalyse).

The two comparisons in Figure 5.10 show how the production from the offshore turbines has more extreme fluctuations than the production from the turbines spread all over the region. They also show that offshore production reaches maximum rated production (or at least a controlled maximum level) quite often compared to land mill production which is quite unlikely to ever do so. Although the offshore profile represents just 160 MW compared to the 2232 MW on land, it is likely that an increase in offshore capacity will enhance the amount of hours with extreme variations.

More precisely, the challenge of generating the 2025 profile (and the steps in-between) is how to upscale the offshore profile while including the effects from the distribution to the three described locations.

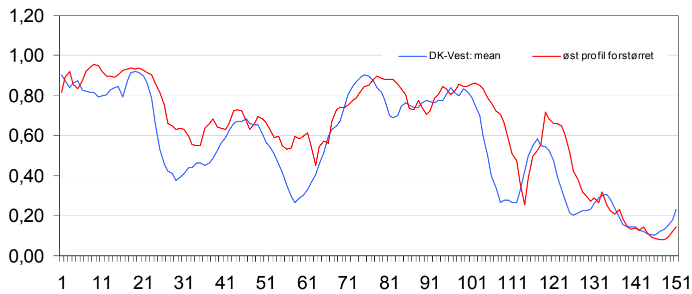


Figure 5.10, Comparison of wind profiles in East- and West-Denmark, respectively indicates a delay between them. The same concept will be added to the generation of an 2025 offshore production profile (data source: Energinet.dk).

The graph above shows, that the two profiles follow the same path, to some extent, but with a couple of hours of delay. The delay could mean that in the particular profile shown, the wind is coming from the West-direction. A similar delay could theoretically characterize the wind production in the different offshore sights. With this in mind, the solution chosen in order to create a realistic offshore profile, is to split the profile into three, upscale each on the basis of the capacities of the three locations, and finally to ad a 3-hour delay. The result of this method can be seen in Figure 5.11 below.

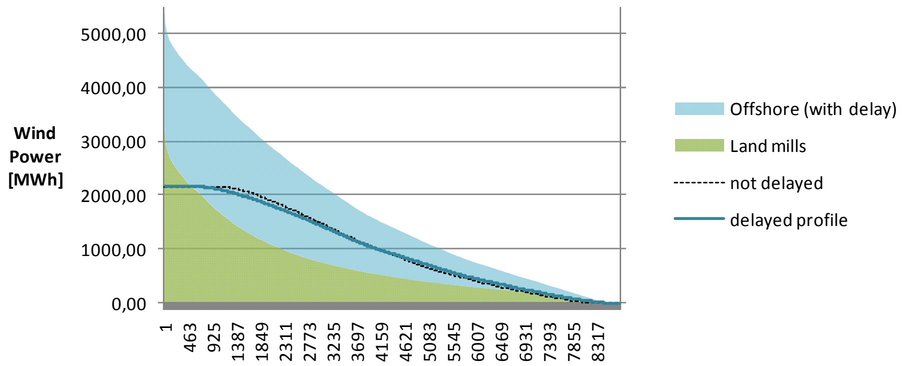


Figure 5.11, Wind profile anno 2025. By applying the delay-method to the offshore profile, the result is a more smoothed out curve with fewer hours of maximum production than else – but, as seen, the number of these hours is still quite high. Looking at the resulting profile of total wind production (appearing in the background) it is seen how the system of 2025 probably will be influenced by wind production with more extreme variations (data source: Ea Energianalyse).

5.4.3. Concluding remark

Although the model is not build to be an exact copy of the West-DK energy system, and that several simplifications (compared to the real system) have been necessary, the model is build on basis of the western Danish energy system, the input is generated on basis of West-DK data – hence the similarities overshadow the differences.

Chapter 6.
Model results

6.1. Overview of the modeled results

In this chapter, the results of the model calculations will be reviewed and analyzed. The results will be addressed one by one according to subject, which means, that for each subject, the results of the three different system scenarios (reference, bypass and heat pump) subjected to the different wind profiles (2008, 2017 and 2025), will be reviewed and analyzed. This means overall that the results have been modeled according to a "three-times-three" sequence as illustrated by Table 6.1 below.

The subjects of the analyses being: energy prices and production patterns from thermal units. Result on the economy and the environmental effects will be reviewed in the following chapter. In this way, the full picture of the consequences of increased wind penetration on all the different subjects will emerge through the two chapters.

Throughout the chapter the terms 'reference scenarios', 'bypass scenarios' and 'heat pump scenarios' will be used with reference to the reference scenario, the bypass scenario and the heat pump scenario, all three being subjected to the three wind profiles, respectively.

	Wind capacity "2008"	Wind capacity "2017"	Wind capacity "2025"
Reference scenario			
Bypass scenario			
Heat pump scenario			

Table 6.1, Illustration of the three system scenarios being subjected to the three different wind capacities, resulting in nine different result output.

The time factor of the modeling and the related problems

The modeled scenarios have been optimized over periods of one month, in general, which as a whole covers one year (meaning that 12 periods have been optimized in this case). However, an unfortunate aspect of solving the mixed integer problem (that the Unit commitment problem is) is that the branch and cut process sometimes continues for a very long time, still searching for the optimal solution (GAMS 2007). As a result, it is sometimes necessary to put a limit to the process by setting the gap size of the solution (see appendix 11.3) at a higher level than necessarily desired. Because the scenario with optional by-pass operation (BPO) includes an extra integer constraint $b(i,t)$, the computation time increased intensively, and so did the error margin. The bypass scenario has therefore been modeled in two different ways: as a full-scale BPO where *all* extraction units have optional BPO, and as a full-scale BPO where just *one* extraction unit have optional BPO.

Mainly the full-scale BPO scenario was optimized with solution gabs, as seen in Table 6.2 below. Correspondingly, some of the optimized month-profiles too resulted in exhaustive[25] tree searches which needed to be terminated within reasonable time (GAMS 2007), but still with much better optimization than in the full-scale BPO scenario, as it appears in appendix 11.4.

GAB sizes, BPO scenario (full-scale)

	windy	non-windy
January	7.9 %	9.6 %
April	10.7 %	9.0 %
July	8.8 %	6.5 %
November	11.0 %	7.5 %

Table 6.2, Relatively high solution GAPs on the optimal solutions found, adding an inaccuracy to the final result of up to 11 % as seen.

Due to these increased computation time and gas sizes, the length of the full-scale BPO-scenario has been limited to periods of only one week, subjected to four different seasons, and each of those subjected to a high and a low wind production, respectively. The modeled sequences are illustrated in **Fejl! Henvisningskilde ikke fundet.**.

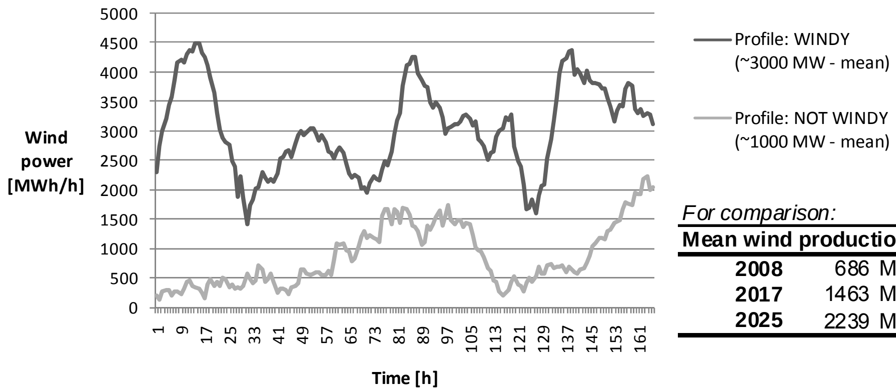
	Windy profile	Non-windy profile
Full scale bypass scenario		
Reference scenario		
Heat pump scenario		

Table 6.3. Illustration of the modeled sequences for the full scale bypass system, windy and non-windy, resulting in two different result output. In addition, the reference and heat pump systems have been subjected to the same profiles for comparison.

The two wind profiles which the scenarios are subjected to can be seen in Figure 6.1. Both the “windy” and the non-windy profiles are taken from the 2025 scenario. Whereas the windy profile represents a relatively high electricity production (~3000 MW, averagely), the not so windy (~1000 MW, averagely) could easily represent the current 2008-

[25] Depending on the “location” of the equilibrium point in relation the different constraints the branched tree size sometimes becomes very large, resulting in a never ending search (if not terminated eventually).

system, and is therefore interesting in a more present perspective. For comparison, the mean wind-production is presented too. Finally, as the full-scale BPO scenario is intended to give an impression of how the BPO option affects the total system, the second model scenario makes it possible to optimize BPO over the entire year.



For comparison:

Mean wind production		
2008	686	MW
2017	1463	MW
2025	2239	MW

Figure 6.1, Two wind profiles used for testing the different system-scenarios up against two wind situations. One which is likely to occur in the future system and one that could take place today (source: Energinet.dk).

6.2. Energy prices

As explained in section 5.2.3, shadow prices of the constraints satisfying the electricity- and heat demands (eq. 5.4, 5.5 and 5.6), can be interpreted as *market prices* on these goods. In the fallowing section the electricity price will be reviewed on the basis of the calculated shadow prices. Focus will be on the amount of critically low prices as these are a direct consequence of electrical overflow[26].

6.2.1. Electricity prices

In Figure 6.2 and Figure 6.3 below, a comparison of the three reference-scenario's price formations in July and January respectively, is seen, showing two months with quite different profiles. Statistically, July is a month of relatively few critically prices hours, whereas January is a month with higher probability of low-price hours, as it also appears from the figures.

[26] The model does not consider the relatively few low-price hours which in the real system are caused by electrical overflow in the Nordic hydro area due to the fixed price.

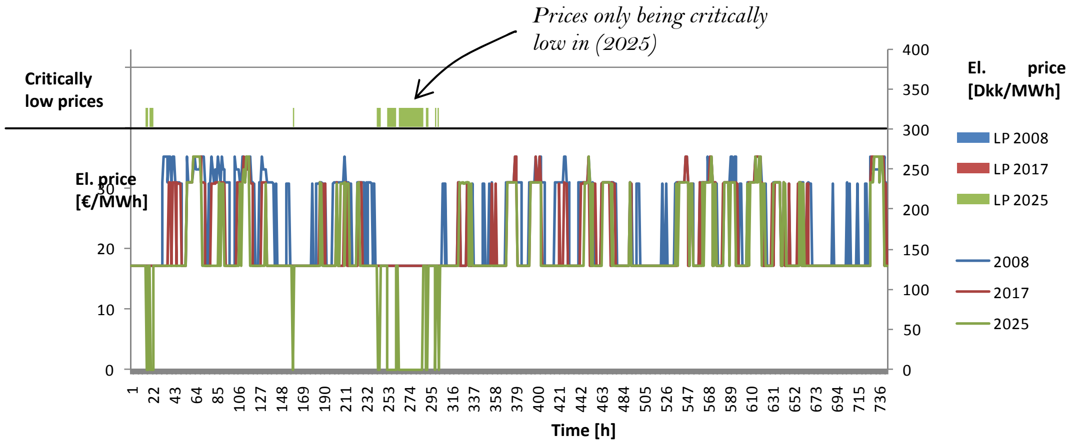


Figure 6.2, Comparison of price fluctuations in the three reference scenarios in July. What seems to look like barcodes above the curves, indicates when prices are critically low (price ~ 0 €). The three scenarios are based on the wind-penetration level in 1) the current system, 2) the system of the objective: 50 % wind (2025), and 3) the “half way” scenario (2017).

As it appears from the two plots, the prices are divided into price steps, e.g. price is either zero in case of wind being marginal utility, 17 € in case of sufficient Hydro power, and thus thermal units forming the next steps. The main reason for this is that the model calculates with a fixed price of ~17 € (300 Dkk) on the hydro production of the exchange area. What is interesting is that the number of hours with critically low prices is much greater in the 2025 scenario than in the 2017 and the 2008 scenarios, for both July and January.

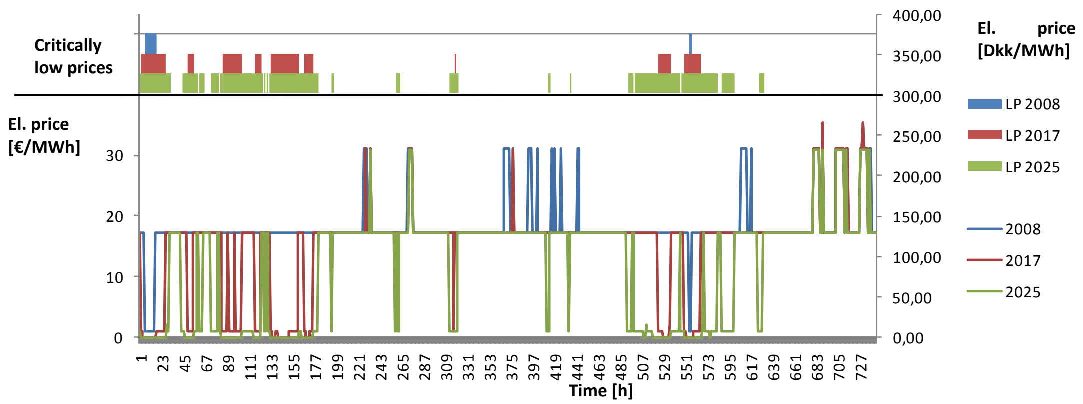


Figure 6.3, The same as in Figure 6.2 with January, showing that critically low prices also occur in the 2008-model though with lesser probability.

In Figure 6.4 below, the price duration as well as the total amount of low-price hours over a total year is shown for the reference scenario subjected to the three wind profiles. The amount of low prices increases significantly as the total wind penetration gradually increases when going from a total capacity of 2400 MW in 2008 to 4000 MW in 2017 and finally to 5400 MW in 2025. In the step from the 2008-scenario to the “halfway scenario”

(2017), which is given by a wind-capacity expansion of 62 %, the amount of low-price hours goes from a quite in-significant number of 146 hours to 1152 hours – an increase of ~ 790 %. The number of low-price hours increases an additional 1358 hours to 2510 hours in 2025, which is in increase of ~1720 % in proportion to the 2008-number. This means, that although the current system of 2008 has a low probability of experiencing electrical oversupply, this phenomenon will appear much more frequently as the wind capacity will be further expanded (if no other changes will be made than the ones already taken into account).

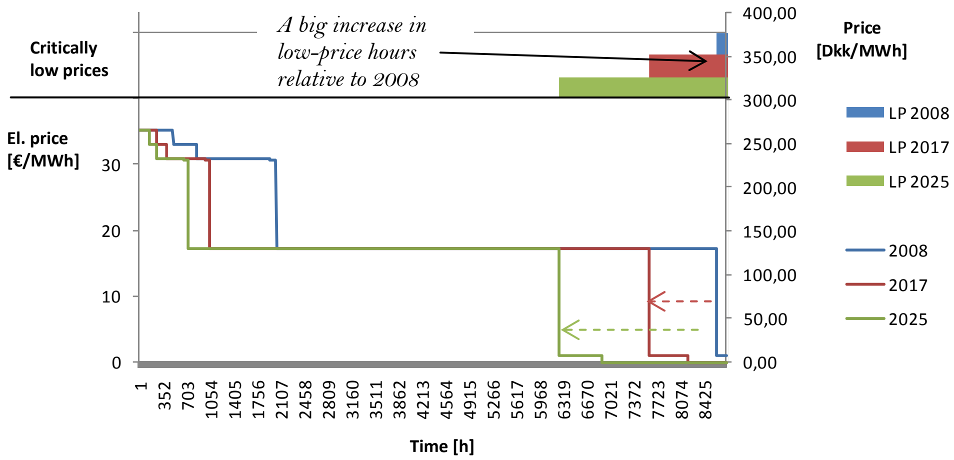


Figure 6.4, Comparison of the annual price-durations of the three scenarios shows how low-price hours increase (with system maintained) when moving towards the scenario of 50 % wind capacity.

Table 6.4 shows some characteristic figures of the electricity price in the three scenarios. As the amount of low prices increase from the 146 hours to the 1152 hours and then further on to 2510 hours, as moving towards the 50 % wind power scenario, the average duration of these periods increase too – going from an average of 5 hours in 2008 to 12 and 15 hours in 2017 and 2025, respectively. *This means that not only will the hours of low prices occur more often; the periods with critically low prices will last much longer as well.*

Periods of low price hours lasting 2-3 times longer than the ones we experience today, might change the basis for decision for the plants, when deciding whether to adapt to these prices - by shutting electricity generation down for example - or to just "run through" (cf. the discussion in chapter 8).

ELECTRICITY PRICE CHARACTERISTICS

Electricity price	**2008**	**2017**	**2025**
Average [€/MWh]	20.45	16.81	13.58
Average, exchange [€/MWh]	18.82	17.00	15.39
Critically low prices:			
Total amount [h/yr]	146	1152	2510
Total share [%]	2	13	29
Average duration of period [h]	5	12	15

Maximum low-price period [h]	17	49	120

Table 6.4, Key figures from modeled electricity prices.

6.2.2. Heat prices

As with electricity, the calculated shadow prices of the heat-demand constraint will be interpreted as the heat price. However, when modeling the co-production of heat and electricity, it is often the case that heat is more needed than power. The co-generated heat and electricity on extraction- and backpressure facilities to some extend are mutually dependent, by which one of the goods may be produced at a lower price than its basic marginal production cost, thereby no longer directly forming the price. As explained in section 5.2.3, the marginal income-loss of one good can be regarded as waste connected with producing the other, and is therefore reflected by an increased price on this. Figure 6.5, which is a sample of electricity prices and de-centralized heat prices, plotted together, shows an example of how electricity-price variations affect the heat price and the other way around.

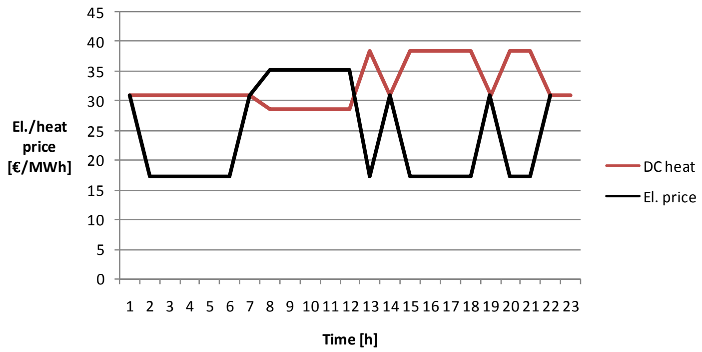


Figure 6.5, Plot of electricity- and heat price. It shows that (when CHP are the marginal utility in the heat market) prices are mutually connected by which a decreasing value of the one causes an increase in the value of the other.

The heat price of the three reference scenarios in the central distribution areas can be seen in Figure 6.6 and Figure 6.7 plotted for January and July, respectively. Although the average heat prices of the two month are close to identical, the variations in the heat prices are characterized by much greater fluctuations in July than in January. Additionally, the heat prices in July have much deeper “price valleys” than in January. When comparing the 2008- , 2017- and 2025 scenarios, the general picture is that the heat prices increase as time goes by, as a result of additional lower prices on the electricity side.

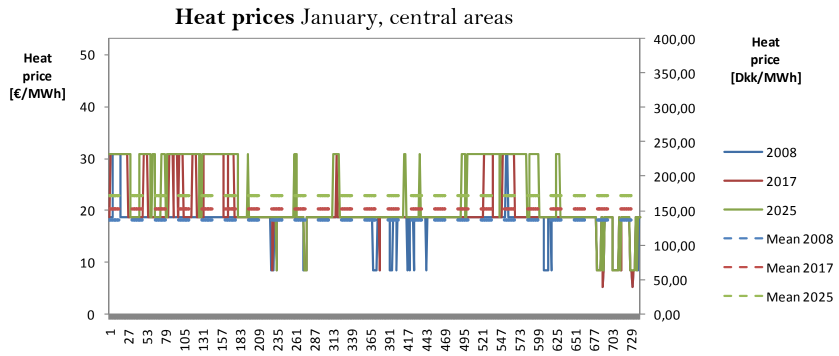


Figure 6.6, Plot of central area heat prices in the reference system subjected to the three wind scenarios in January.

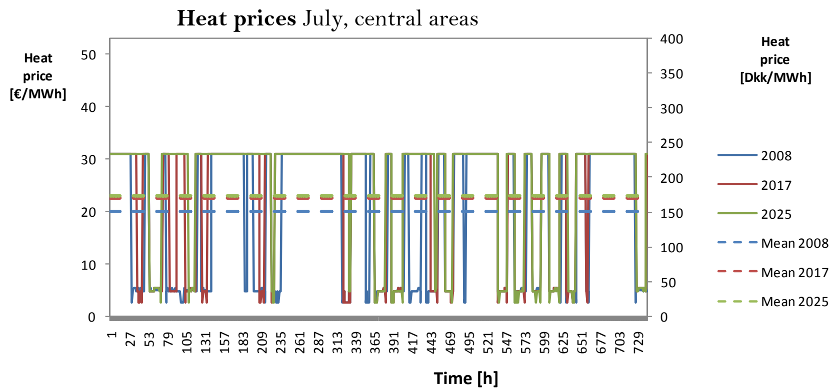


Figure 6.7, Plot of central area heat prices in the reference system subjected to the three wind scenarios in July.

Figure 6.8 compares the duration of heat prices of the entire year in the central and decentralized areas. What is most striking here is that heat is much more expensive in the decentralized heat-distribution areas than in the central ones. Or, put in another way: heat is generally more expensive in the country side than in the urban areas. Table 6.5 below shows this difference in a number of key figures from 2008, 2017 and 2025.

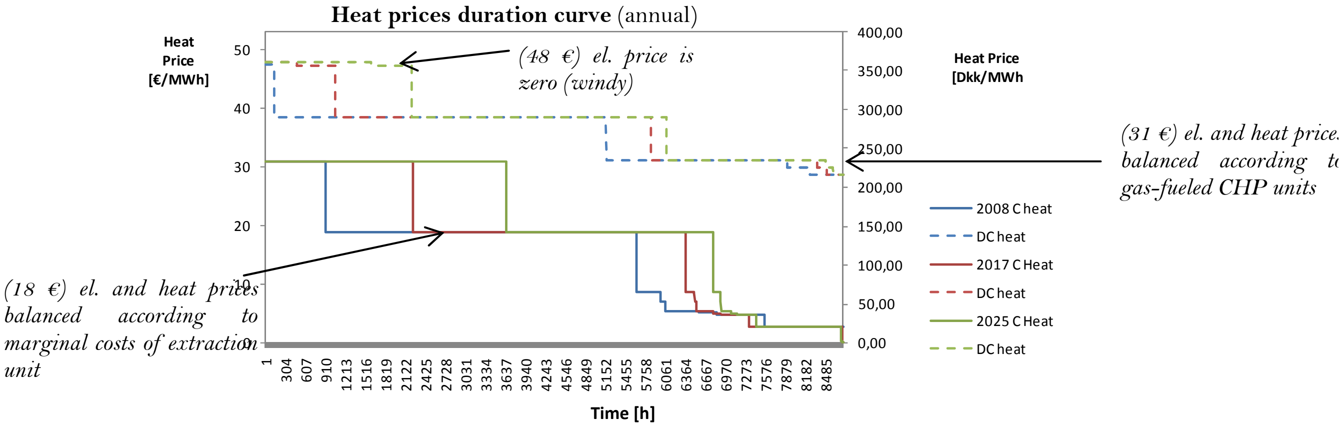


Figure 6.8, Comparison of the annual price-duration curves of the three wind scenarios.

HEAT PRICE CHARACTERISTICS			
Average heat price [€/MWh]	**2008**	**2017**	**2025**
Central heat areas	14.92	17.76	20.38
Decentralized heat area	35.26	36.90	38.39
Maximum heat price [€/MWh]			
Central heat areas	30.86	30.86	30.86
Decentralized heat area	47.25	48.00	48.00

Table 6.5, Annual mean and maximum values of the heat price.

The price difference between the decentralized and the central heat distribution areas is mainly due to two reasons: One is, that the fuel used in the decentralized areas is gas, which, as shown earlier, is more expensive than the coal used in the central areas. The other reason is that around two thirds of the time (as shown in Figure 6.8), the costs of producing electricity on the decentralized facilities are higher than the actual market price. As a result of this, the economic loss is added to the marginal heat-generation costs as “waste electricity”. As shown in Figure 6.8, 31 € is the level where decentralized units are the producers with cheapest marginal capacity available on *both* the el. and heat side. This means that prices above this balanced level can be understood as consisting of an extra-price added to the 31 € - as costs for producing cheap electricity. When comparing the decentralized heat price of the three scenarios, it is seen that the amount of hours with expensive heat prices will increases towards 2025 – especially the amount of the most expensive hours. This is due to the increasing number of hours of electrical oversupply making electricity valueless. The heat price in the central areas shows more or less the same tendency when comparing the three scenarios.

The problem of low electricity prices causing higher heat prices is only of concerns to the part of the decentralized heat production that cannot switch from CHP to pure heat production. Since the decentralized distribution areas (which in the real systems consist of many small areas), has been modeled as one large area, this has not been possible to allow for the fact that some decentralized areas in West-DK might have full boiling capacities and some do not. The single, decentralized area has been modeled with boiler capacity (as an option for hours where switching to full heat production is more profitable), but the installed capacity of 500 MW it not enough for full coverage at all time. I will go into further details on this later on in section 6.3 on the production patterns.

In chapter 4 it was statistically proven that in West-DK, central power plants continue to generate electricity despite of low prices, and it was assumed that this production is forced by the additional heat demand. One could wonder, whether not reacting to the el. market is due to lack of boiling capacity (the amount of decentralized boiling capacity of the current system is presently unknown), perhaps plain conservatism among local CHP operators, or due to some third reason. Nevertheless, it could be interesting to discuss the sense in keep letting local heat consumer co-finance low electricity prices for the benefit of all consumers (including the ones in external power systems). In practice, decentralized producers are often in a position of natural monopoly when it comes to the supply of district heating. Heat-consumers are therefore obligated to pay whatever price might be.

6.2.3. Price formations in the by-pass scenario

In the current project, running in bypass mode means bypassing the high-pressure turbine and, by doing so, giving central CHP plants an opportunity to run entirely as a boiler in times where heat is more valuable than electricity.

As mentioned in the beginning of this chapter, the modeling of the bypass scenario has been divided into two system scenarios. The first is a full-scale scenario, where the system has optional turbine-bypass on all seven extraction units. This scenario is very compute heavy, and has therefore been limited to one-week operation samples as mentioned above. The samples have been modeled on the basis of profiles of the first week of January, April and November, in order to cover different times of the year. July was optimized too, but did not result in any bypass operation and does therefore not differ from the reference scenario. In addition, the samples have been subjected to the 'windy' and non-windy' profiles presented in the beginning of the chapter. In the second scenario, the system is modeled with optional bypass for just one unit and has therefore been modeled for the entire year.

Turbine bypass in the full-scale scenario

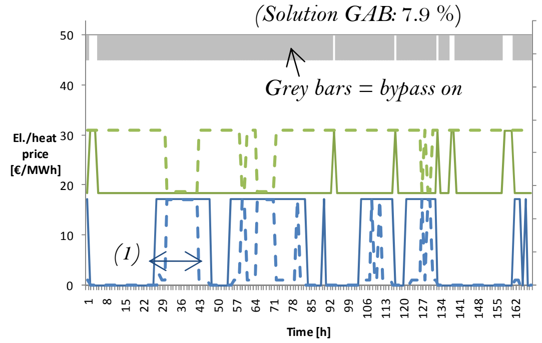
When focusing on the electricity and heat price alone, the main objective of the full-scale model is to see how optional BPO potentially affects the total system, and thus the formation of *electricity* prices, whereas the objective of the single-unit BPO system is to study the *heat*-price formations in the particular distribution area being affected by it.

The six plots presented in Figure 6.9 below shows the results of the full-scale-bypass scenario with all seven units with optional turbine-bypass. However in the figures, the heat price is only plotted for one of the seven distribution systems (all price formations turned out the same because of their individual sizes being scaled according to the CHP capacities). The grey bar above the price curve indicates if the extraction unit of the particular system is operating in BPO-mode. The numbers at the upper left corners of the graphs indicates the solution gabs (the margin of which the optimal solutions are to be found within). Unfortunately, as seen in the full-scaled model, these values were within the range of 6.5 % - 11 %, due to the complexity of the bypass constraints. Although the optimal unit commitment-solution is to be found within a rather big solution area, it is assessed that the results below can be interpreted as reasonable approaches to the affects of full-scale bypass on the electricity price formation.

When observing the unit commitment solutions of the full-scale BPO model below, one of the most interesting things is that no bypass-operation has been "selected" within the estimated optimal solutions in the *non-windy* scenarios (right-side plots). However, this is by far the case in the windy scenarios (left side plots) where bypass is "switched on" most of the time in January, April and November (January being the month with most bypass hours and November the one with the least). The general tendency of the windy scenarios is that the heat price as well as the amount of electrical spill-over, is lower when the BPO is on (see the massive lines) than under normal conditions (see the dotted lines). The electricity price however increases a bit, on an average basis – more specifically, the BPO does not necessary cause a higher *level* in the electricity price; instead, as seen in (1), it reduces the duration of electrical spill-over. This can also be seen in the key figures in Table 6.6 further down.

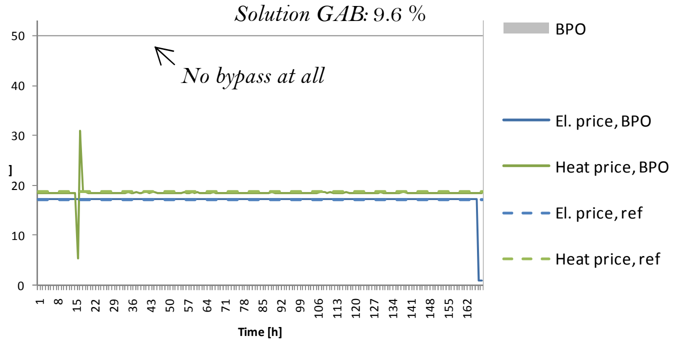
PERIOD: January, 1st week – *windy*

(Solution GAB: 7.9 %)



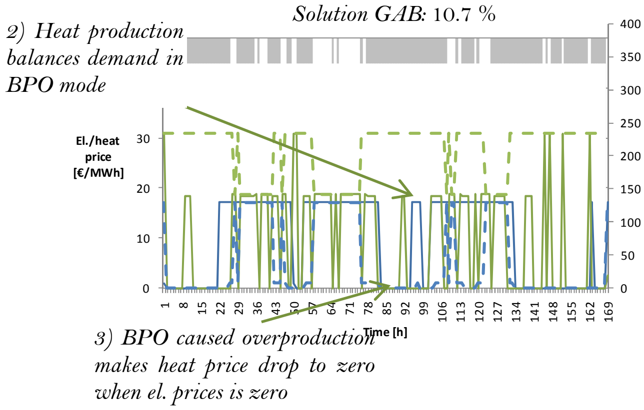
PERIOD: January, 1st week – *not windy*

Solution GAB: 9.6 %



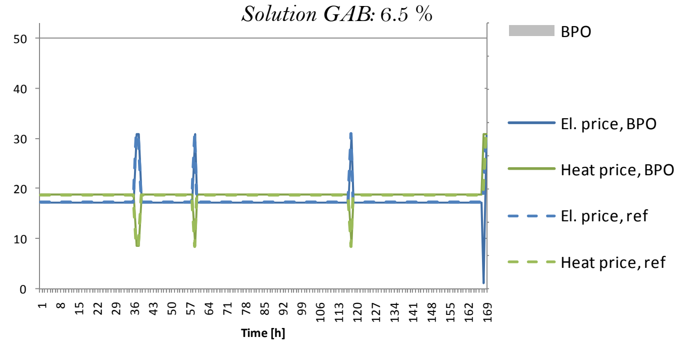
PERIOD: April, 1st week – *windy*

Solution GAB: 10.7 %



PERIOD: April, 1st week – *not windy*

Solution GAB: 6.5 %



PERIOD: November, 1st week – *windy*

PERIOD: November, 1st week – *not windy*

Solution GAB: 7.5 %

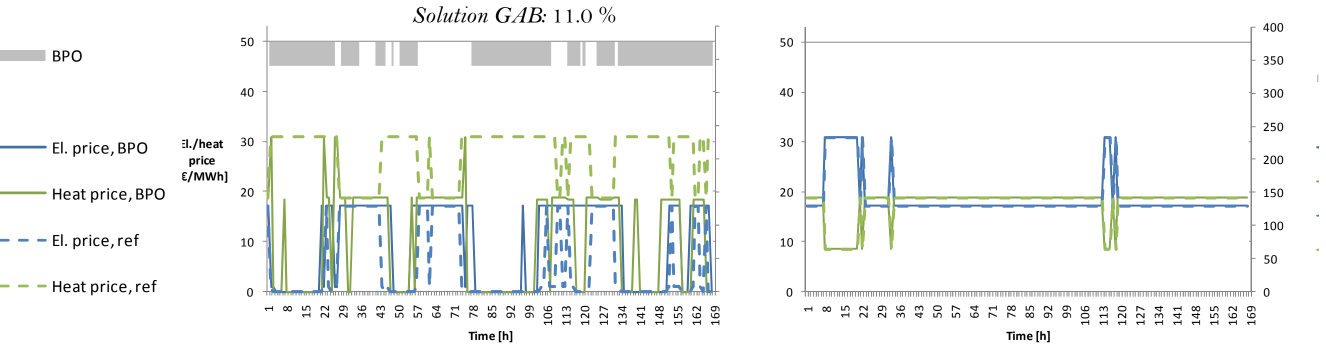


Figure 6.9, Comparison of prices in the bypass and reference scenario, subjected to the windy and non-windy profiles, in weekly samples from Jan., Apr. and Nov..

A “market failure” is seen in the windy scenario for April and November, respectively (see note 3 Figure 6.9), in that the heat price and the electricity price quite often drops to zero simultaneously when the PBO is “turned on”. This seems illogical since the heat- and electricity price normally are inversely correlated. However, the reason that both the electricity and the heat price turn zero during bypass-operation is simply that the lowest heat production possible (due to the minimum boiler capacity) exceeds the heat demand, thus creating an amount of waste-heat. Although it seems crazy to “burn of” heat, the model’s choice is still a cheaper alternative than running under normal co-generation. The problem of this waste-heat is that the heat price, reflecting the extra costs of producing another MWh of heat, drops completely to zero as the satisfaction of the heat demand already is exceeded, and the marginal heat unit becomes free. As the ‘choice’ of the optimization model to oversupply the heat demand, resulting in a zero heat price, would not be the case in practice, and is thus entirely related to the logic of the model.

Figure 6.10 and Table 6.6 below shows the electricity prices in a system with optional bypass operation, compared to the price formations in the reference system, both exposed to the windy profile. It is seen, that the full-scale BPO has a positive impact on the amount of hours with low electricity prices – particularly in January, where the heat demand is high – resulting in an average electricity price almost three times as high in the BPO scenario as in the reference scenario. Although these solutions are found with an accuracy of around 10 %, based on Table 6.2, it seems as if the full-scale BPO to some extend balances the heat price up against the electricity price throughout windy periods.

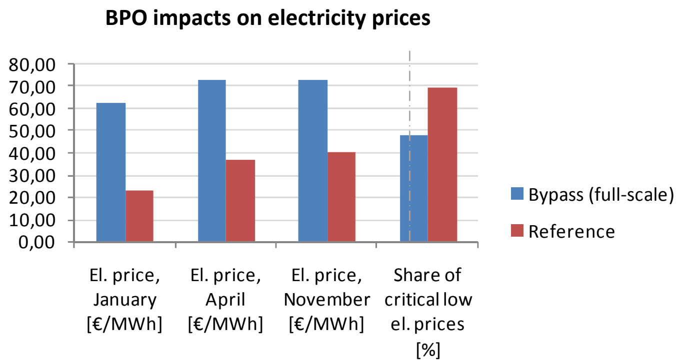


Figure 6.10, A comparison of the average electricity prices in two systems exposed to the windy profile – one, with full-scale BPO, and one being the reference system, showing that the BPO scenario results in higher electricity prices, as well as a lower probability of electrical overflow.

		SCENARIOS			
Prices [€/MWh]	month:	Windy		Not windy	
		BPO	ref	BPO	ref
EL	Jan	8.29	3.05	17.00	17.20
	Apr	9.63	4.90	17.43	17.52
	Nov	9.61	5.25	18.75	18.75
	mean	**9.18**	**4.40**	**17.73**	**17.82**
HEAT	Jan	19.26	29.14	18.42	18.76
	Apr	9.13	27.62	18.59	18.52
	Nov	9.96	27.46	17.60	17.60
	mean	**12.78**	**28.07**	**18.20**	**18.29**

Table 6.6, Shows in numbers the same as in the figure to the left, plus the drop of the heat price – particularly being the case for April and November. A price drop that is further enhanced by the BPO-caused overproduction of heat, as just described.

Turbine bypass applied to a single extraction unit

When it comes to the modeling of the bypass on a single extraction unit, it has been possible to model the entire year without compromising the level of feasibility too much. In this scenario, however, only the heat price will be of interest since one unit alone with optional BPO will not have significant influence on the electricity price.

In Figure 6.11 is a plot of the heat-price duration in one distribution area with optional BPO for the particular extraction unit, exposed to the wind profiles of the 2008, 2017 and 2025 scenarios, respectively. As above, the dotted lines indicates the heat price of the reference scenario and the massive ones the BPO-scenario. When comparing the heat prices in the two scenarios, it seems as if the heat prices in the system with applied bypass is relatively untouched by the rather extreme wind profiles of 2017 and 2025, whereas the heat prices in the reference scenario increases when going towards the 2017 and 2025 wind scenario – especially when it comes to the higher prices. One of the main reasons why the price does not increase considerably during the steps of increased wind power, is exactly the PBO option. Normally, as seen in the three reference scenarios, the amount of forced electricity increases as the wind power increases, and thereby shortens the upper "price block" to the right (see Figure 6.11), or to put in another way: extends the amount of low price hours. With the BPO option applied, the amount of forced electricity is reduced and thus, *the average price is held constant despite increased wind penetration.*

As in the full-scale bypass scenario the single unit bypass scenario generates zero-heat prices which, as mentioned above, are caused by the model choosing to overproduce heat in bypass-mode rather than co-generating (in backpressure mode). Because of the spill of heat, the model registers the marginal MWh of heat as free and returns a zero shadow price, thus neglecting the interest of the facility owner.

1) Heat price-level at 31 € means el. price is zero

2) Increased wind penetration extends this price level further

3) 18 € - el. and heat price is balanced

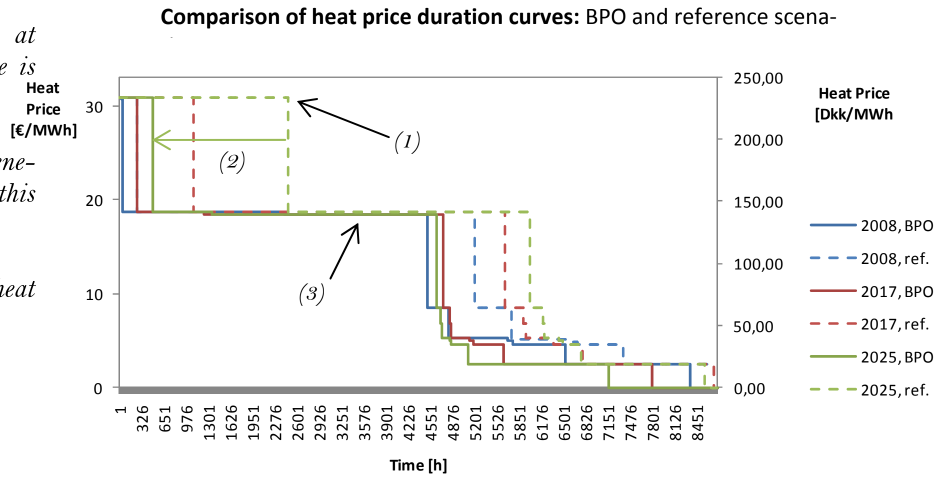


Figure 6.11, Comparison of heat-price durations in the scenario with bypass is applied to one unit and the reference scenario (dashed lines), showing that BPO controls the heat price level.

The numbers in Table 6.7 show likewise how the annual heat price in the bypass scenario is constant around 11 € throughout the three steps of wind capacity extension, whereas the price in the reference scenario goes from an average of 13.4 € in 2008 to 15.0 € and 17.4 € in 2017 to 2025, respectively. In practice, the prices are maintained at the same level because of the optimization algorithm often choosing the bypass mode, as soon as the electricity price becomes critically low.

Heat price [€/MWh]	**2008**	**2017**	**2025**
With turbine bypass	11.45	11.55	11.38
Reference scenario	13.41	14.98	17.36

Table 6.7, Comparison of average heat prices, showing that the value of heat is maintained towards the 2025 scenario in the BPO scenario, as apposite to the reference scenario, which increases.

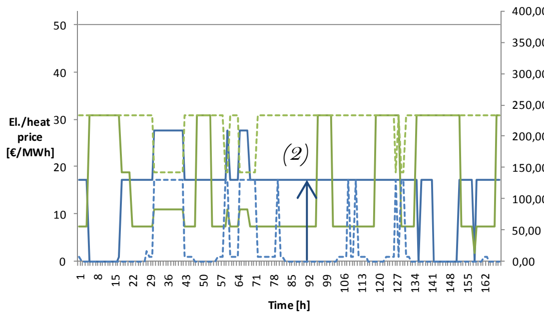
6.2.4. Price formations in the Heat pump scenario

The third and final modeled scenario is the system with heat pumps included in the central and decentralized distribution systems, thereby converting electrical- into thermal energy (while additionally extracting earth heat). In order to compare the impact of heat pumps on the entire system with the impact of full-scale bypass (presented in the previous section), the heat pump system is optimized as one-week samples of a windy and non-windy profile from January, April, July and November, respectively, to begin with. In this way, the variations of the impact of the heat pumps at different times of the year become clear. Afterwards, an optimization over the entire year will be presented.

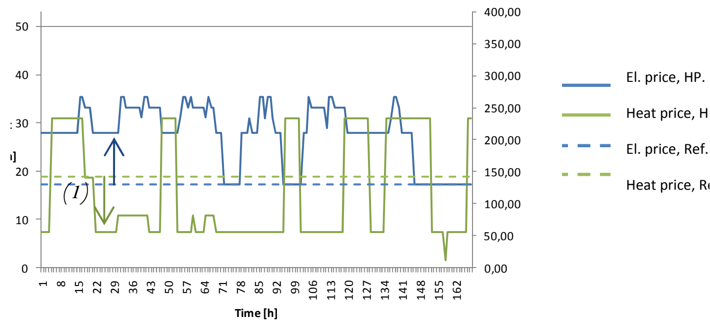
For comparison with the observed impacts from BPO seen earlier, Figure 6.12 below presents the plots of the corresponding heat pump-scenario in the first week of January, April, July and November, respectively. As in the previous scenarios, the dotted lines indicates the heat price of the reference scenario and the massive ones the heat pump scenario. What is striking, is how the heat pumps more or less turn around the heat and electricity price formations, causing an increased electricity price- and a fall in the heat price level. An example of this is the non-windy week of January (1.b) where the price on electricity as well as the price on heat, in the reference scenario, are stable and close to similar, opposite the heat pump scenario, where the electricity price on average increases and the heat price on average decreases (compared to the reference scenario) (1.b note 1). Another characteristic of the modeled solution is that the heat-pumps seem to prevent electrical spill-over, by reducing the amount of zero-prices (1.a note 2) connected to the increased wind power.

Another consequence of including heat pumps, when observing the absolute values on an hourly basis, is the generation of faster fluctuating electricity- and heat prices (compared to the reference system), especially significant in the April-sample. Furthermore, the price steps are more detailed in this model. The reason for this might be the inclusion of electricity as a "fuel" in the heat pump model, whose costs (opposite to conventional fuel) varies by the hour. The result is a price coupling of the heat and electricity systems that works opposite to the CHP price coupling.

1.a) PERIOD: January, 1st week – *windy*

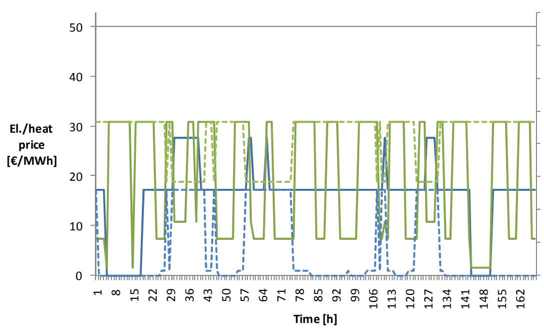


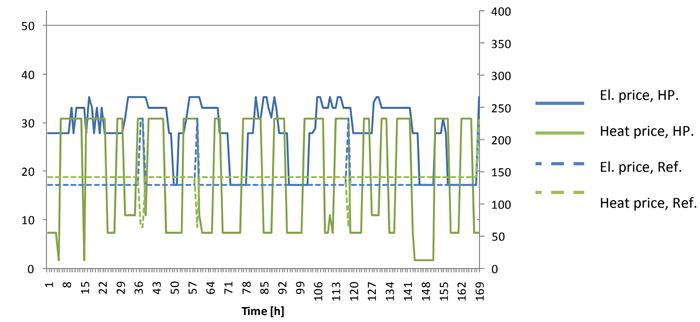
1.b) PERIOD: January, 1st week – *not windy*



2.a) PERIOD: April, 1st week – *windy*

2.b) PERIOD: April, 1st week – *not windy*





4.a) PERIOD: November, 1st week – *windy*

4.b) PERIOD: November, 1st week – *not windy*

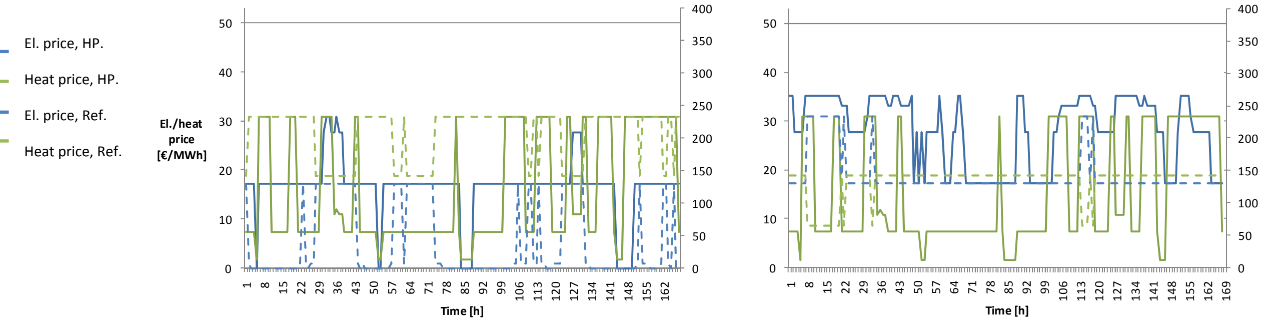


Figure 6.12, Comparison of prices in the Heat pump and reference scenario, respectively, subjected to the windy and non-windy profiles, in weekly samples from Jan, Apr, July and Nov..

In order to get a more detailed result, the heat pump scenario has also been optimized for the entire year. In Figure 6.13 the calculated electricity prices when including 900 MW total pump capacity (subjected to the three wind profiles) are plotted, together with the electricity prices of the reference scenarios for comparison. As shown in the figure, the electricity price is much higher in the heat pump system than in the reference system, especially in the 2008 scenario (1). The reason for this price-increase when including heat pumps is that, despite a relatively high price on heat-pump "fuel" (electricity price = 30 €), the marginal costs of the heat pumps are able to compete with the exiting heat producers, thus raising the price on electricity further.

Electricity price duration: heat pump vs. reference scenario

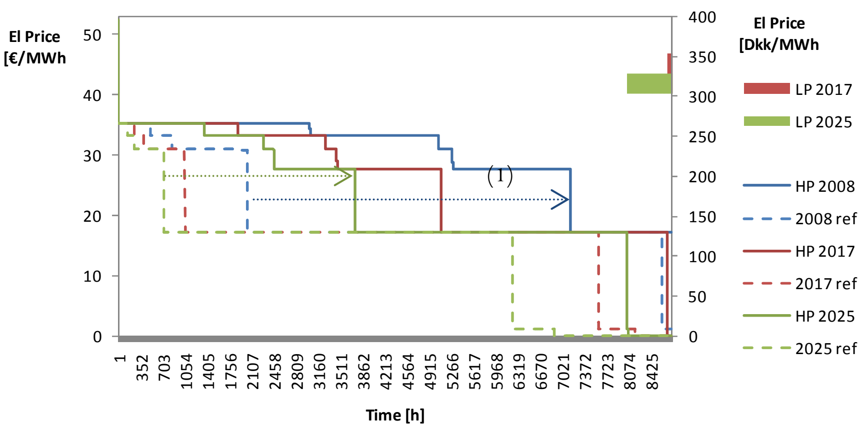


Figure 6.13, Comparison of el. prices in heat-pump and reference scenarios by their duration curves. Note how the price duration curves in all three heat pump scenarios (massive lines) are "pushed" to the right, resulting in a higher el. price on average basis, compared to the el. prices of the reference scenarios (dashed lines).

The impact on heat prices from including heat-pumps in the modeled system is shown in Figure 6.14 and Figure 6.15 , showing price duration for central distribution areas and decentralized distribution area, respectively. In the central areas (Figure 6.14), heat pumps almost completely manages to prevent changes in the prices despite of the increased wind capacity (as seen in the reference scenario). This is first of all done by replacing the more expensive marginal heat producers, and secondly, by balancing the electricity price so the marginal costs of heat no longer need to cover the spill of generating free electricity. However, the “price” of maintaining a constant shape of the heat-price duration curve below, seems to be reflected in the increased electricity prices, as shown above.

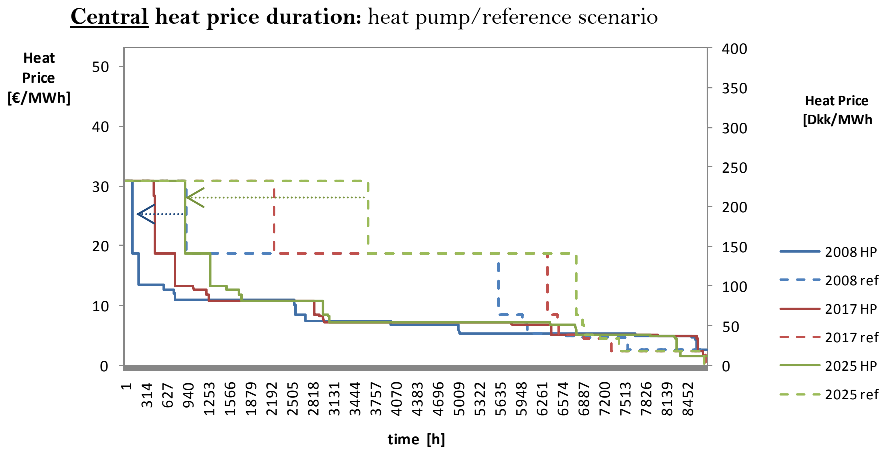


Figure 6.14, Comparison of duration curves, showing heat pumps impact on the central heat-price. Note here, that the heat prices between the wind scenarios are almost equal in the heat-pump scenario.

One of the most interesting impacts of heat pumps on the heat price-formation is seen in the decentralized system shown below in Figure 6.15. Compared to the central area, the heat price in the reference system is very high in the decentralized area, but this difference seems to be leveled out when introducing the heat pumps. Or put in another way: the heat price in decentralized areas ends up at a level corresponding to the central area when introducing heat pumps, at the given pump capacity. An interesting potential.

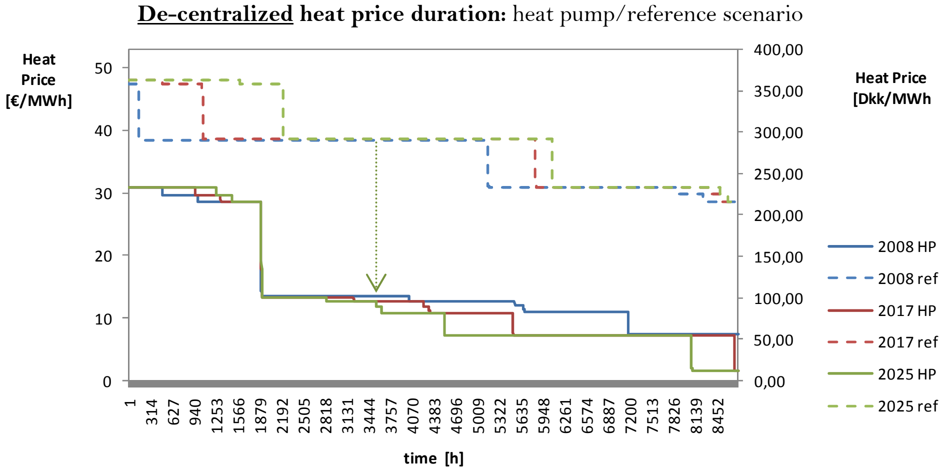


Figure 6.15, Duration of heat prices in the decentralized distribution area showing significantly lower prices in the heat-pump scenario.

6.2.5. Comparison of price characteristics of the heat pump, the BPO and the reference scenario

Finally, Table 6.8 below contains details on the electricity- and heat price characteristics of the heat pump scenario, the full-scale BPO scenario and the reference scenario. The table is based on the on the optimized one-week samples of a windy and non-windy profile from January, April, July and November in order to compare the three scenarios.

When comparing the price characteristics of the three scenario, it is evident that the heat-pumps manages to equalize the heat and the electricity price in the windy scenario with a price of14.7€/MWh and 14.1 €/MWh, respectively. By doing so, the system with heat-pumps generates the highest average electricity price in both the windy and non-windy scenario compared to the two other scenarios. Whereas the heat-pump scenario includes the ability to convert electricity to heat, the BPO scenario can choose to stop producing electricity while continually producing heat, working like a boiler, thus having a price-balancing effect in the windy scenario too. This is seen in the table below, where the average electricity price in the PBO scenario is 9.18 €/MWh and an average heat price is 12.78 €/MWh (compared to the average electricity and heat prices of 5.44 €/MWh and 28.75 €/MWh in the reference scenario).

Prices [€/MWh]	month:	SCENARIOS: Windy (~3000 MW) HP	ref	BPO	Not windy (~1000 MW) HP	ref	BPO
EL	Jan	15.70	3.05	8.29	27.39	17.20	17.00
	Apr	16.07	4.90	9.63	28.25	17.52	17.43
	Jul	10.57	8.55	-	27.44	22.43	-
	Nov	16.46	5.25	9.61	27.98	18.75	18.75
	mean	**14.70**	**5.44**	**9.18**	**27.77**	**18.97**	**17.73**
HEAT	Jan	15.67	29.14	19.26	15.67	18.76	18.42
	Apr	19.74	27.62	9.13	19.74	18.52	18.59
	Jul	5.19	30.79	-	5.19	21.89	-
	Nov	15.76	27.46	9.96	15.76	17.60	17.60
	mean	**14.09**	**28.75**	**12.78**	**14.09**	**19.19**	**18.20**

Table 6.8, Comparison of price characteristics of the Heat-pump, the BPO- and the reference scenarios under the impacts of the two wind-profiles. Note here that the solutions found in the full-scale BPO scenarios have a rather large error margin (the *mean* values represent the average calculated from a time basis).

When comparing the price formations, the BPO-scenario seems to generate the lowest heat prices, as well as the second cheapest on the electricity side – especially in windy periods. However, reality might be that the values are set too low due to the impact from BPO generated zero-price. Despite of this, it can be concluded from these results that heat pumps as well as BPO have balancing impacts on the heat and electricity prices, compared to the reference system.

In Table 6.9 below, a comparison of the relative amount of critically low prices in the three systems is shown. The numbers thereby indicates how effective the system scenarios with heat-pumps and turbine bypass, compared to the reference system, can reduce the amount of hours with critically low electricity prices, due to electrical spillover in the windy period. As seen in the table, the heat pump system is by far the most effective, keeping the amount of low-price hours at ~20 %. For comparison, the reference system generates ~70 % of low-price hours within the same, strong wind penetration. In addition, the BPO system also has a limiting effect on the amount of low prices, reducing this amount to 48.2 %.

SCENARIOS:	HP	Reference	BPO
Amount	19.4 %	69.3 %	48.2 %
Mean duration	8.0 h	12.9 h	11.2 h

Table 6.9, Comparison of the share of critically low electricity prices in the 3 systems, subjected the windy profile. Note the relatively smaller difference in the mean duration of critical hours.

6.2.6. Summary on energy prices

In section 6.2.5, the characteristics of electricity and heat price-formations in the different modeled scenarios have been studied. The modeled scenarios have been divided into a reference, a bypass and a heat-pump scenario and each of these been subjected to the profiles of the 2008, 2017 and 2025 wind production scenarios for an entire year. The full-scale bypass scenario however, has only been optimized for samples of one week in each of the four seasons, subjected to a windy and non-windy profile, respectively. This is due to the unfortunate high level of complexity causing gaps on 6-11 % on the optimal solutions. For better comparison, the reference and heat-pump scenarios have therefore been modeled this way too.

Since the focus of this section has been price formations alone, one of the main topics of interest have been the amount of critically low prices. In this connection it was found that under normal conditions (reference scenario) this amount increases strongly as the wind penetration changes, from a relative insignificant 146 low-price hours in the 2008 system, to 1152 in 2017, and finally 2510 hours in the 2025 scenario. And as the amount of electrical spillover hereof grows – so does the expected duration of the low-price periods, from an average duration of 5 hours in 2008, to 12 and 15 hours in 2017 and 2025, respectively. An outcome that possible changes the framework of the discussion of what it should take for large power plants to adjust to the low prices, in relation to the economical and technical issues connected to the starting-up/shutting-down, and rapid power regulations, respectively.

When observing the heat price-formations it was obtained that, a consequence of the growing wind production, the heat price (as the electricity price drops) increases from the forced contribution for producing cheep (and sometimes free) electricity.

From the optimization of the bypass scenarios it was seen that the optional BPO-mode, in the full-scale scenario, prevents some of the cases of electrical spillover, and thus (when subjected to the windy profile) increases the mean electricity price from ~4 €/MWh to ~9 €/MWh, while it simultaneously lowers the additional heat price from an average of 28 to 13 €/MWh. It can generally be said that the BPO helps balancing the falling electricity prices and the increasing heat prices. However, the observed low heat price is unfortunately affected by a model-related market failure, which sometimes generates *zero-heat prices* simultaneously with zero-electricity prices, as a result of the heat-oversupply of heat during BPO.

Regarding the heat pump system, one of the main findings was the impact of the applied heat pump capacity on the prices, as the system leveled out the price difference of heat and electricity. The average electricity prices however, increased dramatically (by up to a factor of five) when going from the reference- to the heat-pump scenario. Nonetheless, the most significant impact from heat pumps, is the almost complete balancing of, on one side, the rather high heat prices in the decentralized area, and on the other side, the lower prices in the central areas, creating an indirect 'cash flow' from the urban areas to the local areas.

6.3. Production patterns

In the previous section the price characteristics of heat and electricity of the different modeled scenarios have been shown. Following in this section is the results of the optimized production patterns. As in the previous section the characteristics of the optimized electricity production will be analyzed at first, followed by the analysis of the heat production. Focus will be on the variations in the production, compared by analysis of the different scenarios. The productions will be categorized after: wind power, extraction units (as a whole), condensing unit, decentralized units, boilers, and heat-pumps as well as import from the hydro units in the exchange area. The production patterns will furthermore be analyzed in relation to the balancing of consumption of heat and electricity, and the resulting export and import. As the modeled systems are exposed to increasing wind capacity, their ability to fully exploit the wind power, and thus to avoid electrical overflow, is expected to be put under increasing pressure. The amount of utilized wind power in the different system scenarios will therefore be analyzed, and in the light of this, the factor of import and export will be illuminated. In the case of production patterns of central units, the annual length of commitment as well as the amount of full load hours of each plant will be highlighted. This is important in connection with a further discussion of the value of the various capacities and of the power plant's individual economy, which will take place in the succeeding section on economy (section 7.2).

6.3.1. Balancing electricity demand

In this section the production patterns of the electricity generation as well as the as the factor of import and export in the three modeled scenarios will be accounted for.

Power generation in the Reference system

In Figure 6.16 below is plotted a sample of the production patterns from the first week in January, showing the reference system subjected to the 2008 wind profile. The wind production shown is from a rather windy week of the 2008 wind-profile with an average production of 903 MW (only 22.3 % of the production in the annual profile is equal to or above this level of average wind production). The green area indicates the electricity generation from de-centralized units, the red layers the extraction units, and the blue area indicates wind production. Furthermore, the grey area indicates the production which, in order to balance the demand, have to be exported. Conversely, the yellow area is the import from the exchange area used for balancing.

When looking at the figure it is seen that the first day is windy, which – combined with a relatively low level of consumption that particular day – results in hours with critically low prices, and a large quantity of export (light grey area). The following two days is characterized by import from the exchange area (yellow), and on the fourth day, the wind production almost balances the internal consumption resulting in a quiet day for the external connection. In the weekend, the consumption once again drops and the area start exporting again. When looking at the price level it is seen that the imported hydro production of the exchange area, except from in the few critical hours when the price is at ~17 €, represents the marginal utility the whole time, in spite of the large production from CHP units (red and green areas). Condensing units have not been committed at any time.

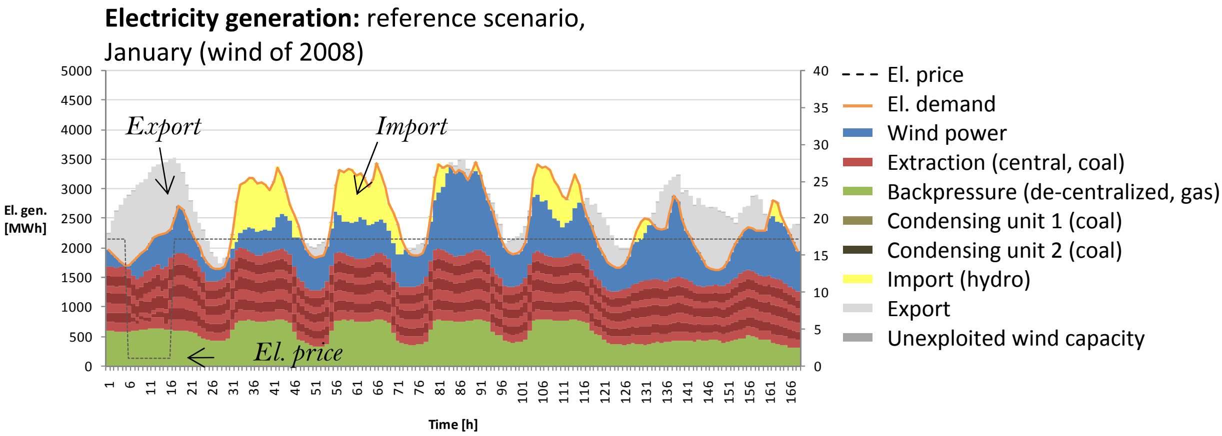


Figure 6.16, First week of January (starting out with a bank holiday) exposed to the wind capacity of 2008. Note that the seven nuance-layers of the red part indicate the extraction units.

Figure 6.17 below shows the same week of the reference scenario now subjected to the 2017 wind profile, making the profile-sample reach an average wind production of around 2000 MW (200 % increase from 2008). Around 5 % of the entire 2017 profile is equal to or above this level.

Compared to the 2008-wind capacity, the result of the 2017-wind profile is that 1) no import is needed at any time, 2) the formed price varies between being critically low and at the marginal cost-level of hydro power (~17 €), and 3) since limit of export-capacity is suddenly reached, the system being forced to down-regulate. A phenomenon previously described as electrical spillover. Another interesting deviation from the 2008 scenario is what appears to be a complete down regulation of the extraction units in the periods where the price is completely zero, but without capacity being shut down. Assuming that the extraction units (as it is a cold period), are running at maximum heat output (backpressure mode), the additional heat seems to be produced by other facilities with lower marginal *heat*-costs, due to the electricity price being practically valueless in these periods. Finally, the overall characteristics of the 2017-reference scenario are, that the need for export has increased considerably – especially at night – and as a result of this, the periods of critically low prices have increased too.

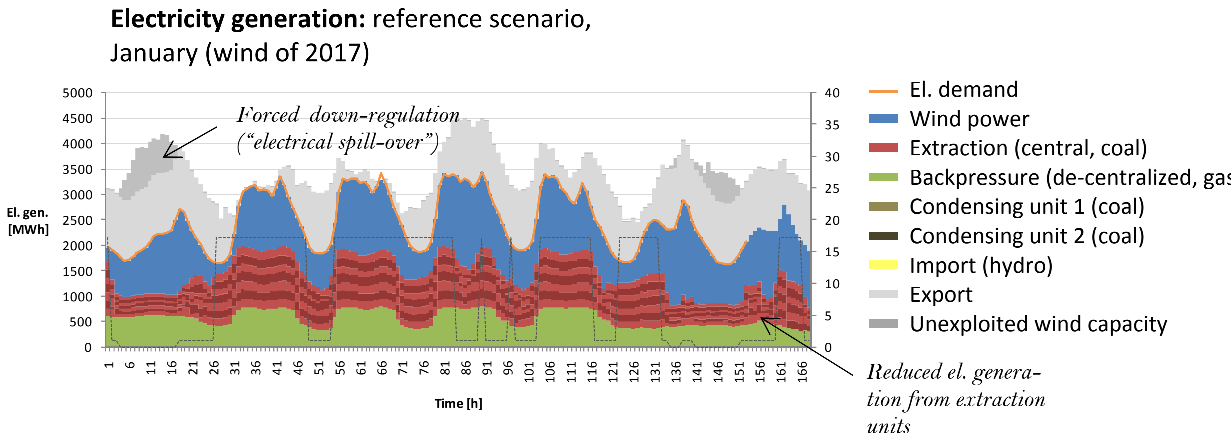


Figure 6.17, The same week-sample subjected to the 2017 wind-capacity.

The impacts of the 2025-wind capacity are shown in Figure 6.18 below, and it is rather extreme. In this case (in the observed week of January), wind production reaches a level of averagely 3000 MW, marking the limit of the just 20 % most wind productive hours of 2025.

In the 2025 sample below the fallowing main characteristics of the production pattern are shown: 1) the amount of unexploited wind power, and thus the periods of electrical overflow, has increased considerably, 2) extraction units are not just down-regulating production, but directly de-committing until the absolute minimum of three plants (excepts for daily peaks), 3) being constrained by the heat-demand, the de-centralized units generate power at an almost constant level and 4) the price level is critically low almost the entire sampled period.

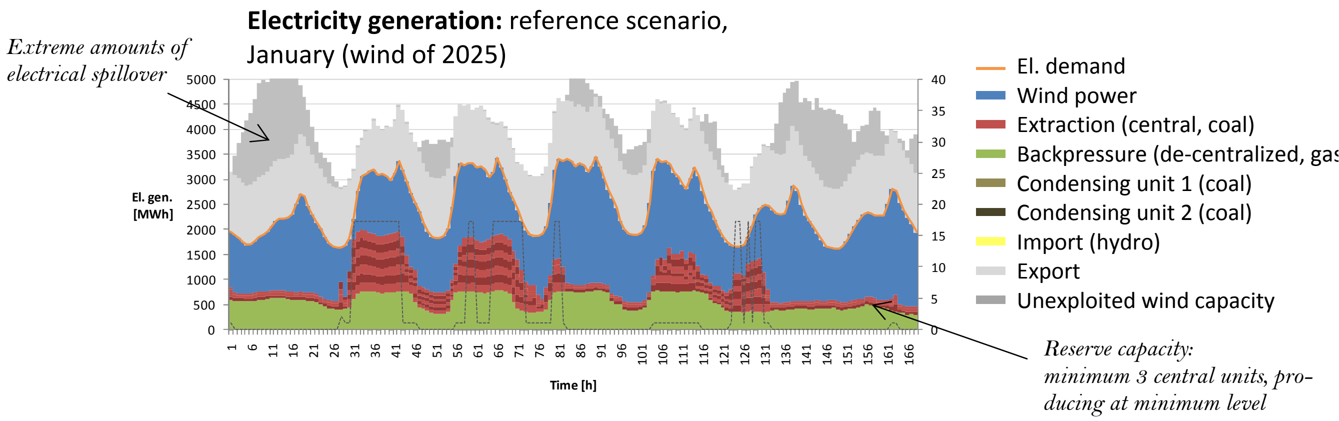


Figure 6.18, Week-sample from reference scenario subjected to the 2025 wind-capacity.

As the average wind power production of the shown 2025-sample marks the limit of the 20 % most windy hours seen over the year, the mentioned system problems of the 50 % wind power scenario (2025 scenario) will be the case – if not worse – at least 20 % of the time – unless a number of system adaptations are made before then.

Figure 6.19 below shows the characteristics of the production patterns over the entire modeled year, highlighting some of these critical issues.

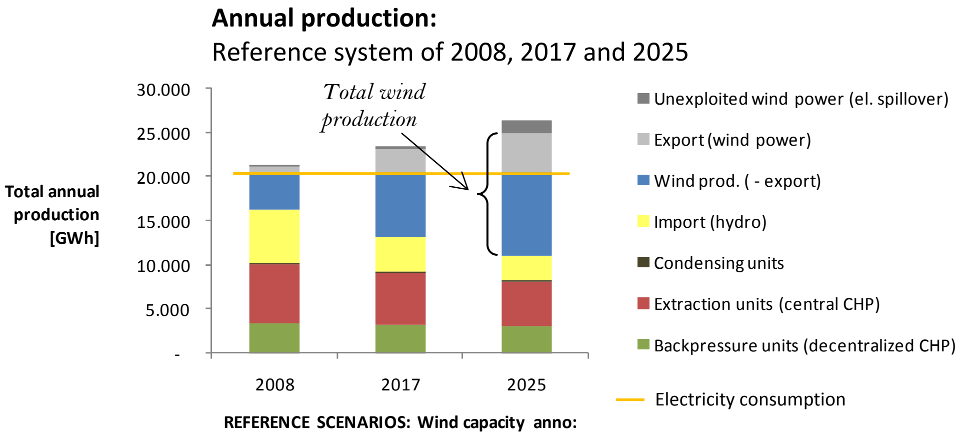


Figure 6.19, Comparison of total annual production, import and export presented same way as the previous production pattern graphs. On the graph, the exported quantities are included in the wind production.

When comparing the annual production figures above (2008, 2017 and 2025), it is seen how the quantities of exported power (light grey) as well as the surplus wind capacity (dark grey) increases steadily towards the 2025-wind scenario, while the yellow area, which marks the import of hydro power steadily decreases. Note in this connection, that hydro power in the model has been given a low, fixed marginal value of 17 € (just below the extraction units), ensuring that the hydro production always 'plays' before any other facility – except for wind off course – at the market. This means that export towards the exchange area only will occur at prices equal to, or below, the 17 €. The fixed level of the variable hydro-costs is set lower than the normal average value of the real system.

This fact is supported by Figure 6.20 below, comparing the average production patterns of the modeled 2008-reference scenario to the real data from West-DK from the period 2004-2009. It is seen here that the imported amount of power, in the modeled system, is around three times as large as seen averagely in West-DK 2004-2009, which could indicate that assumed marginal costs of hydro is lower than in the real system – on an average basis. Normally, in the real Nordic system, the value of hydro will occasionally be is much higher due to water shortages.

It is also seen that the generated wind profile for 2008 results in a higher amount of wind production than in the real West-DK. The lower rate of import as well as the slightly lower wind production (in the real system) is then matched by an almost twice as high production from central units. Also, the decentralized production is a bit higher in the West-DK data.

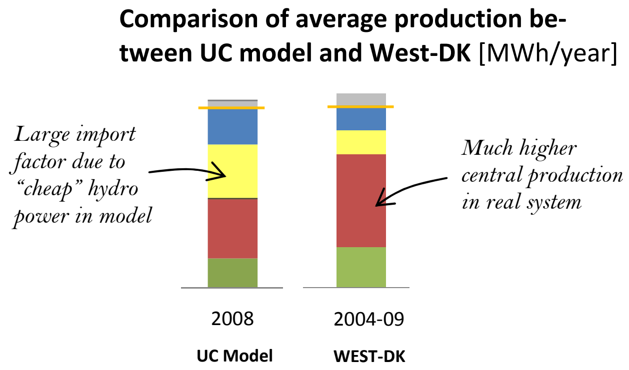


Figure 6.20, Comparison of model to West-DK by mean production [27].

As in Figure 6.20 above, the production patterns of the three wind profiles is shown in Figure 6.21 below, but this time only for the hours with critically low electricity prices (less than 5 €). It is seen, that on average the demand increases towards 2025 in the hours with critically low price. Furthermore, in 2025, the wind power manages to replace the constrained power generation from extraction units to a minimum level, whereas electricity from decentralized backpressure units seems relatively unaffected. It is also seen, that the export level is at its maximum in all three cases, because of the external capacity limits being reached, resulting in an increase in the amount of spilled wind production towards 2025 (indicated by the dark grey area). Finally, low price-hours are characterized by a great amount of wind production in all three cases.

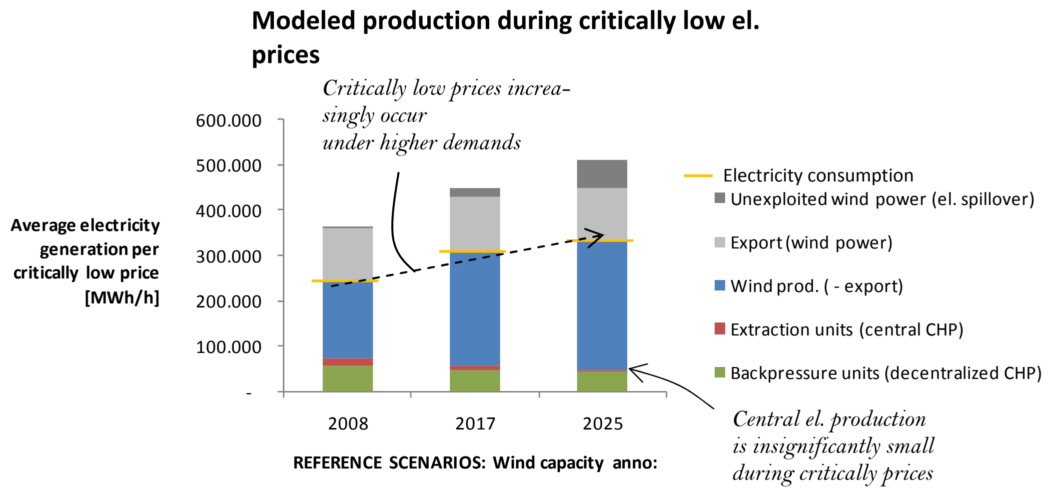


Figure 6.21, Comparison of total annual production of the hours of critically low prices.

[27] West-DK consumption is averagely 3 % higher that the consumption of model.

One of the problems with the model is seen when comparing with the distribution-bars from the real West-DK system (2004-2009 average). Figure 6.22 below compares the production in critically low hours for the modeled system and West-DK, respectively. One of the main differences is that whereas central production in the model is almost completely suppressed, this is not the case in West-DK where the amount of constrained power[28] from central units is relatively higher. The modeled central units simply seem too "perfect" responding to low prices, when compared to the data from the real system. The main reason for this though, is that the model has more boiling capacity installed in the central heat-distributions than the West-DK area. However, knowing that central producers usually possess a fare amount of boiling capacity as back-up, there could be other reasons behind the refusing of producing at a low scale as well (observed in the real system).

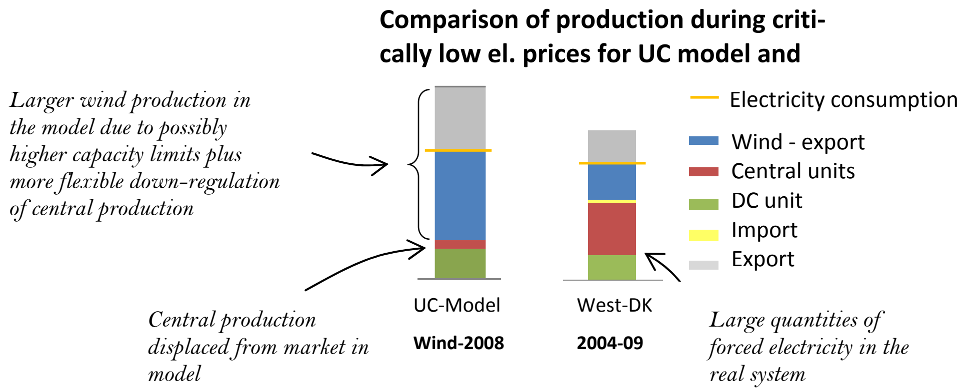


Figure 6.22, Comparison of average production under critically low prices in the model and West-DK, indicating a much more flexible Central production despite of various technical constraints taken into account. Average consumption is around 11 % higher in the model than in West-DK in these hours.

So far, the model results prove (to some extend) that central extraction units can down-regulate to a much lower level than what have been the case in West-DK (on an average of 2004-2009). There should be no strong, technical arguments against extraction units producing for hours, or even days, at a minimum level. The only technical consequence of doing so is a lacking ability to rapidly restore a normal production level (Lindboe). With this in mind, an explanatory factor for the much larger amount of heat-constrained power generation from extraction units in reality, than in the model results, could be that the central units have been modeled with too great regulatory skills, given the assumed up-ramp gradient of 200 MWh/h boiling power (see section 5.4.1). Although these are technical issues that would require further analysis of the properties of the central units as well as of possible system conditions responsible, the reserve capacity-condition (demanding at least three units committed), seems excludable from the main sources causing the observed amount of fixed electricity.

[28] Thermal power generation can in general be assumed constrained in hours with critically low electricity prices.

Another main difference between the model and West-DK, allowing higher wind production in the modeled system than in reality, is the average level of export in the hours with critically low prices, which is about twice as high in the model as in West-DK. In case this difference is due to lower external transmission capacities, one might argue, that this problem has been taken into account in the model, given that the interconnection of the model was fixed with the capacity of 1200 MW (for a realistic approximation), corresponding to the sum of the average announced capacities towards Norway and Sweden (being 1000 and 650, respectively under normal conditions). Moreover, neglecting Germany as export-option should theoretically create bad enough export conditions to approximate reality. Nonetheless, the model still has a higher export rate. Although a reason for this could be that a part of the low prices are created externally, making West-DK an importer for a few hours (see yellow area), it was proven in section 4.6 that the vast majority of critically low prices were generated internally. Therefore, the rather low export-level observed in West-DK (Figure 6.22), seems to be caused by bad conditions for external transmission.

Instead of discussing expansions of the external capacity, or how to improve utilization, (for instance through more effective congestion management), which normally is discussed, focus in this project is on feasible ways of reducing the heat-forced electricity from the central extraction units and the decentralized backpressure units – in the figure indicated by the red and green areas. In the following section the impacts of extraction units with optional bypass-mode on the production patterns will be reviewed.

Power generation in bypass scenario

In this section the optimized results of electricity generation in the full-scale bypass scenario will be reviewed. As in the earlier section, the shown result are from the first week of January and November (Figure 6.23 and Figure 6.24 respectively), both subjected to the windy profile (first week of 2025 wind capacity-profile). As mentioned in the previous sections, the results of the full-scale bypass scenario are given as rough optimizations, which in the case of "on-off" switching of bypass mode, may have influenced the level of detail in the model. Reserve capacity restrictions are assumed uncompromised by the full-scale bypass solution, c.f. equation (5.28) in the model description (chapter 5), as units are regarded as committed when operating in bypass mode (for further elaboration see heat production-patterns later in section 6.3.2).

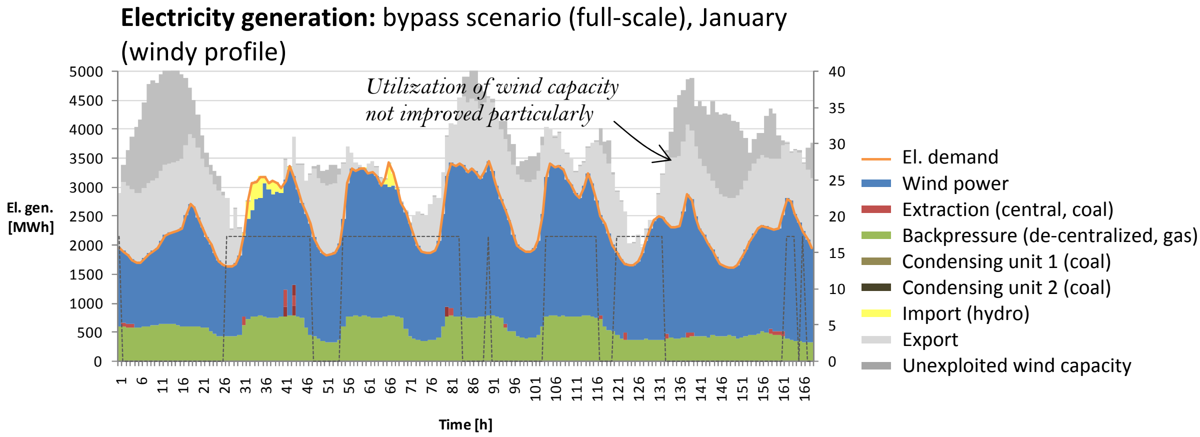


Figure 6.23, Plot of electricity generation in bypass scenario, first week of January subjected to windy profile. Optional BPO has resulted in an almost complete absence of central power generation.

When comparing the two plots (Figure 6.23 above and Figure 6.24 below), it is seen that BPO almost completely shuts down electricity generation on extraction units in January, and most of the time in November. Judged by the patterns in November alone, it seems like there is a relation between operating with bypass, and the combination of wind production and electricity demand. More specifically, whenever there is a surplus of wind capacity (indicated by the dark grey), BPO is switched on, and when the wind power later again drops to a level of full utilization, the units are likely to switch back on. However, this is not quite the case in January, where units run in bypass mode despite of low wind production. This indicates that extraction units also are more cost-efficient as pure heat producers, while prices are not critically low. The plots also indicate that the November-profile utilizes the wind capacity slightly better than the January profile. The reasons for this is: 1) that the consumption "fits" the wind profile a bit more and 2) that lower heat demands in the decentralized areas are "freeing up" a part of the heat-constrained power generation, resulting in an increased supply from wind power. When comparing January to the same week in the reference scenario of 2025 (equal wind profiles), the wind-utilization have not improved significantly. However, this is not necessarily to be explained by BPO being ineffective, but rather by the extraction units of the corresponding reference system, which, as previously seen, were being substituted by the more expensive boiler capacity due to the valueless electricity price. Meaning, that if there were not so much central boiling capacity to replace extraction units, as the case being, there would possibly have been a more positive effect from the BPO, when compared to the reference system.

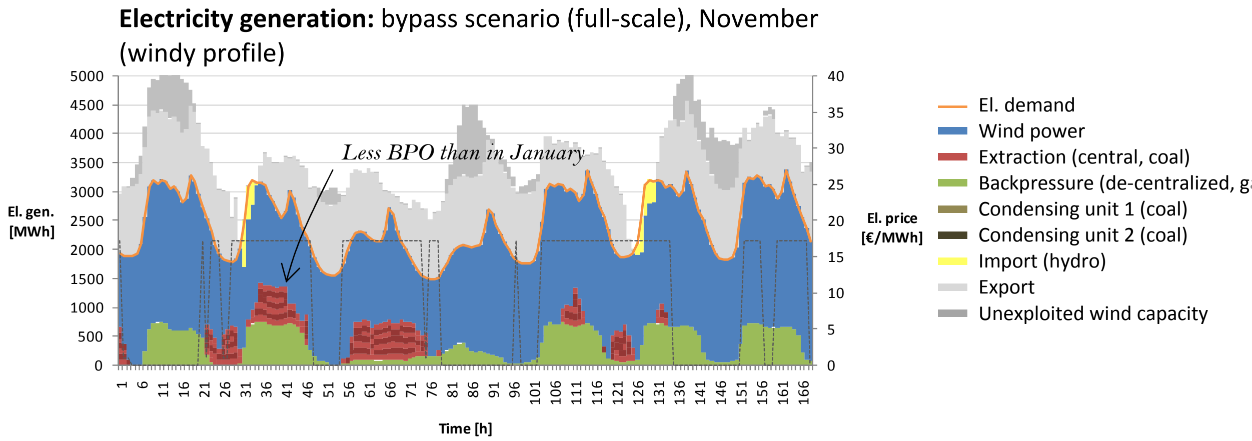


Figure 6.24, Plot of electricity generation in bypass scenario of November, subjected to windy profile. BPO is not chosen the entire time.

The comparison of the two plots from January and November above furthermore shows, that in a cold month like January, switching to bypass mode is generally more attractive than co-generation, whereas co-generation sometimes is more optimal for the system in November, as a result of the smaller heat demand plus slightly increased electricity demand (due to less constrained decentralized power generation). Additionally, we see a tendency towards a better utilization of wind capacity in November (wind profiles are equally windy). To support these facts Figure 6.25 below indicates the total production share of the different utilities.

Comparison of the week-results, seen in Figure 6.25, (once again) shows that in all three weeks the total power generation from extraction units is reduced in the full-scale BPO scenario in comparison with the reference scenario – especially in January, where the heat consumption is high and the electricity consumption relatively low[29] (in the sample). The most important, positive factor distinguishing the two scenarios is the reduced exported power in the BPO scenario, compared to the reference scenario. This is because the probability of electrical spillover in the real system may be higher than in the modeled system (due to constant varying transmission capacities) although the exported quantities seen in the reference scenario is easily handled by the model – a model of a system that disregards internal stress levels of transmission and has a fixed export capacity rate.

When looking at the results of the production patterns in the bypass scenario, the primary knowledge is that the value of bypass seems to increase with increasing wind capacity, especially in periods with high heat consumption, thus, making bypass suitable for cold, windy times.

[29] The specific week of observation is with 3 bank holidays, resulting in a decreased total consumption.

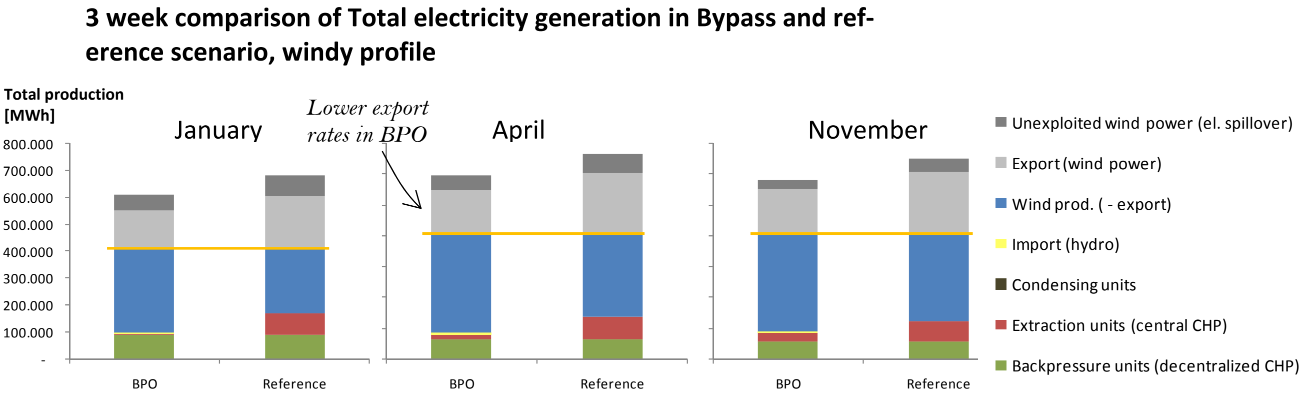


Figure 6.25, Comparison of total production of the three selected weeks. Note the variation in un-utilized wind production, thermal electricity production (red and green), and exported power.

Power generation in the heat pump-scenario

In this section we will take a look at the results of the production patterns from the heat-pumps scenario, subjected to the wind capacities anno 2008, 2017 and 2025, using the same approach as in the two previous sections. To shortly sum up from section 5.4, the heat pump-scenario is modeled by installing a total capacity of 350 MW in the seven central heat distribution-areas (allocated in accordance with the local heat demands), plus installing an additional capacity of 500 MW in the decentralized areas. The assumed efficiency (or COP value) of all heat pumps is 300 %. Given the rather large capacity installed, the heat pump scenario in some ways is regarded as a more extreme scenario than the bypass scenario, seen from a system change approach. The results and experiences obtained from the optimization presented in the fallowing therefore most of all serves as a study of the potential value of heat pumps.

Theoretically speaking, heat pumps add a new characteristic to the interplay between heat and electricity generation. So far we have seen (in connection with co-generated heat on thermal units) that whenever the electricity price drops, the corresponding heat price typically increases. With heat pumps however, the heat- and the electricity prices will follow each other simultaneously due to the connection between the electricity price and the marginal heat costs. This has a balancing effect reducing the difference between the heat and electricity price.

The production patterns in the heat pump system with wind-capacity anno 2008 are seen from the plot in Figure 6.26. As shown here, the main characteristics of the heat pump system is: 1) Full internal utilization of wind power, 2) insignificantly low electricity generation from decentralized units, 3) “full steam” on condensing units during daily peaks, 4) a great amount of import, and finally 5) an increase in electricity consumption from the electrical heat pumps.

The main reasons why the system manages to, not only consume the produced wind power internally, but also to have a large rate of imported hydro power, is the combination of increased electricity consumption from heat pumps (by 17 % compared to the reference scenario), as well as the replacement of constrained power from backpressure units with heat pump production. In addition, a great part of the power generation from extraction units have been displaced with wind power (in comparison to the reference scenario), particularly between daily peaks, thereby "making room" for further amounts of imported electricity.

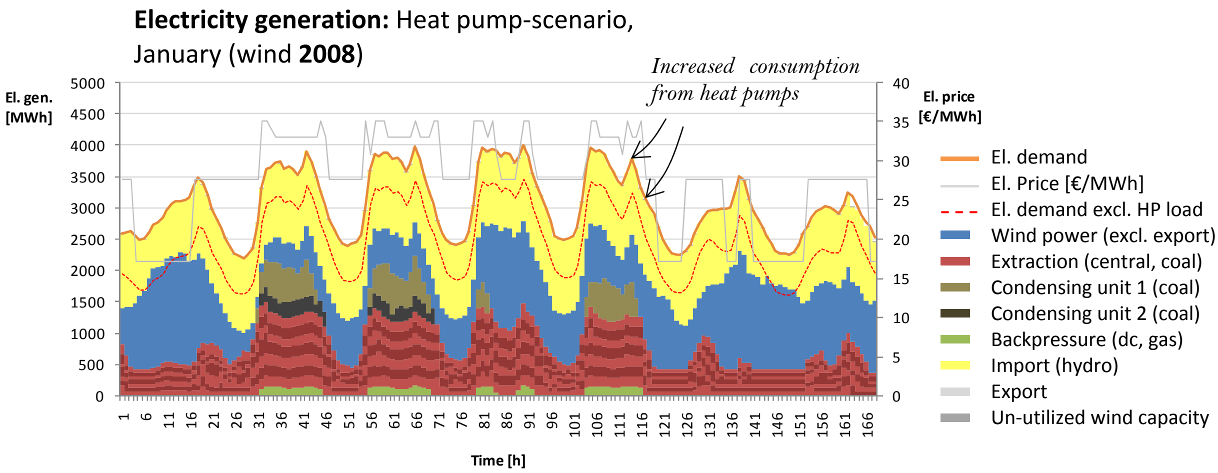


Figure 6.26, Plot of electricity generation in heat pump scenario in January, subjected to the 2008 wind capacity. Note here, that the electricity consumption (indicated by the dashed, read line) has increased significantly, and that decentralized power is almost displaced.

Moving on to the heat pump scenario subjected to the 2017 wind-capacity, a plot of the production patterns is seen in Figure 6.27 below. As seen, the power generation from extraction units (red) has decreased further as a result of the increased wind production, causing the electricity price to drop. This price-drop helps heat pumps produce cheaper heat to replace thermal co-generation further with. The plot indicates that in low consumption-periods the extraction-units are operating at the lowest level possible, and in a few short periods, just three units are committed – a symptom of central production being unneeded. Moreover, the electricity consumption of heat pumps is changelessly high; the import rate has decreased, and there appears to be a few hours of export.

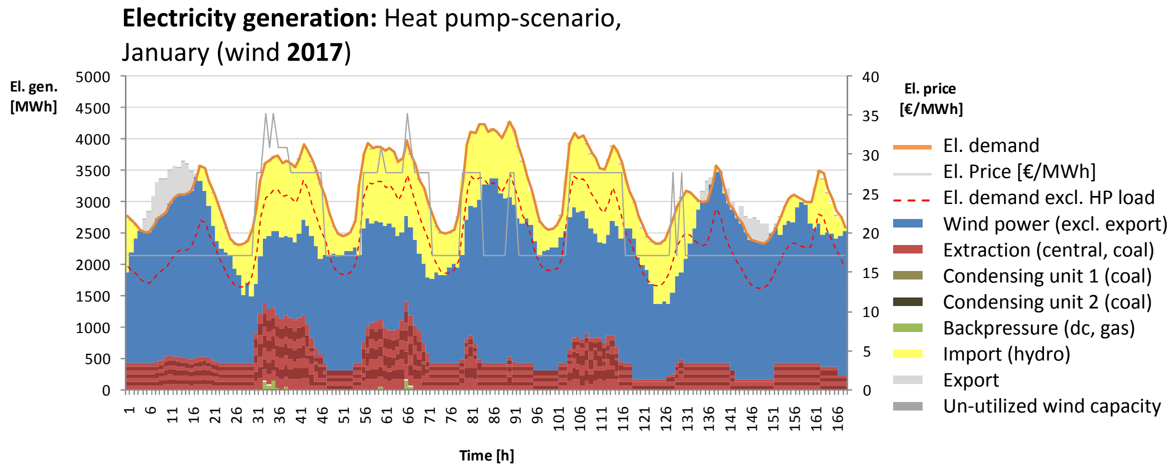


Figure 6.27, Plot of electricity generation in heat pump scenario in January, subjected to the 2017 wind capacity. Power generation from extraction units is further displaced as wind power increases, and the corresponding backpressure production almost gone.

The heat pump scenario subjected to the 2025 wind-capacity (plotted in Figure 6.28 below), shows a steady continuation of the tendencies seen in the 2017 heat pump-scenario. And additionally, we now for the first time in this system experience a slight occurrence of electrical spillover as seen within the low consumption periods.

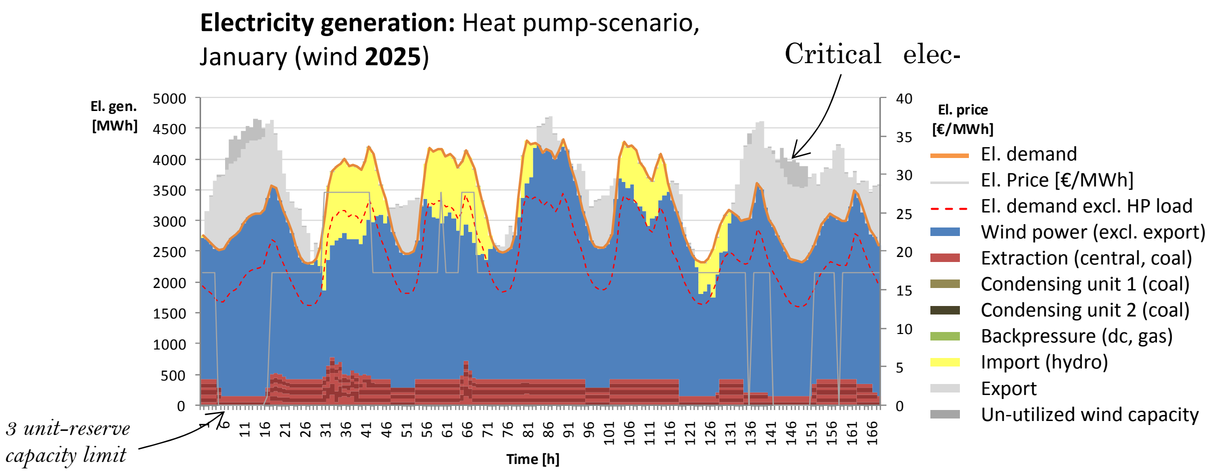


Figure 6.28, Plot of electricity generation in heat pump scenario in January, subjected to the 2025 wind capacity. As a result of a lower electricity price caused by the increased wind production of 2025, extraction units are forced to regulate down to a lowest possible limit, and sometimes even de-commit.

When comparing the production patterns from the heat pumps system subjected to the 2008, 2017 and 2025 wind capacities shown above, it appears as though heat pumps with 300 % COP factor is the most economic of the producing alternatives (almost completely displacing central production in windy periods with additionally low consumption) as long as hydro or wind power represents the marginal utility of the merit order of power supply. This will be further elaborated in section 6.3.2 (heat patterns) where the heat patterns will be analyzed.

As in the previous sections, the bars in Figure 6.29 below represent the annual production in the three wind scenarios, showing that the included heat pump capacity has a significant impact on the total production, when comparing to the results of the corresponding references scenarios.

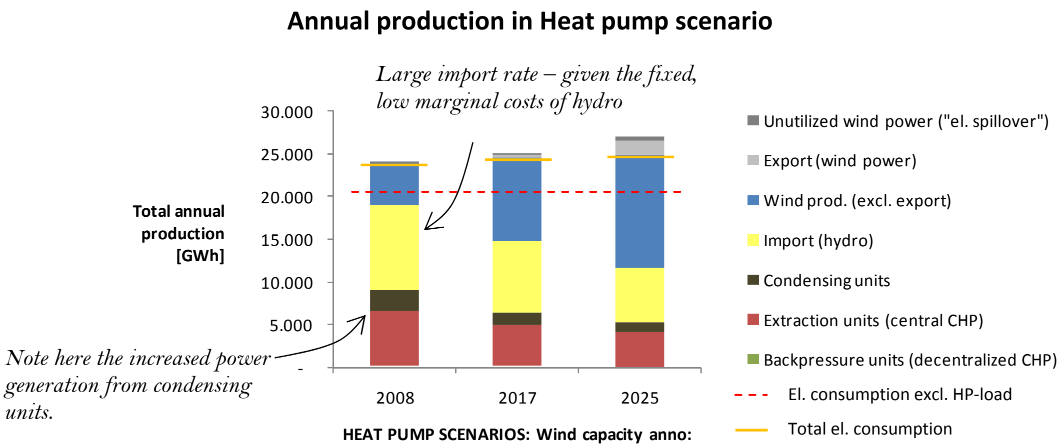


Figure 6.29, Comparison of total production in the three wind scenarios. Until 2025, the exported amount is practically nonexistent, as well as the import very high – particularly in 2008.

As shown in the figure, the main decentralized power generation is almost completely replaced from the optimized heat- and electricity supply. The power generation from extraction units seems relatively unchanged compared to the reference scenarios, and a new tendency towards increased electricity production from condensing units is shown. Greater amounts of electricity from condensing units indicate that the price on electricity has increased to such an extent where it pays to optimize the electricity production – even by condensing power. Since the steam units are coal-based, the observed development is interesting in an efficiency and environmental perspective, and will be discussed later on in chapter 7. Furthermore, this system scenario results in an incredible large amount of imported hydro, and one could ask, if this is realistic in relation to the Nordic power system. Although the total electricity load of West-DK is relatively low, compared to the other Nordic countries, the probability of one third of West-DK being supplied from Nordic hydro power seems low – especially when assuming a constant low price level as in the model. Due to hydro shortage, a more logical scenario would probably be that the value of hydro would increase, by witch electricity from CHP units would become more cost-competitive, resulting in a more balanced production pattern in favor of thermal units than the case being in Figure 6.29.

6.3.2. Balancing the heat demand

In this section the production patterns of the optimized heat production in the model will be accounted for. The procedure will be the same as with the electricity patterns in the previous section - beginning with the reference scenario, moving on to the full-scale bypass scenario and finishing with the heat pump scenario. The reference and heat pump scenario subjected to the three wind profiles, and the bypass scenario only subjected to the windy profile as optimal solutions of the full-scale bypass system only was found with reasonable accuracy when modeling smaller samples of one week (cf. section 6.1).

To sum up from section 5.3.1, the central and decentralized heat distribution areas consist of supply from co-generated heat from extraction- and backpressure units (central and decentralized, respectively), boiler capacities in each area, and finally: heat pumps, (only in the heat-pump scenario).

Reference system

The heat production of the reference system subjected to the 2008 profile is seen in Figure 6.30 below. In order to separate the central and the decentralized heat consumption, the consumption curve has been divided into two consumption curves – one indicating the total heat demand (yellow) and one indicating the heat demand for the decentralized distribution areas (orange). The heat price from one of the seven central areas (blue curve) as well as the electricity price (dashed white), is displayed too.

Figure 6.30 shows the heat production in the 2008-reference system. Regarding the central areas, it is seen that the heat supplied by extraction units is the most economic option, except when the electricity price drops to a critical low level – then boilers are more economic efficient. Contrary to this, the model prefers boiling capacity over backpressure units in the decentralized area in the entire optimized operating hours. The reason for this is simply that both boilers and backpressure units operate on gas, and that the CHP net-efficiency equals the boiler-efficiency. As a consequence of equal (total) production costs, the optimization model will prefer boilers as soon as the electricity price drops below the power generation cost of the backpressure units (which the marginal heat costs, correspondingly, will have to compensate for). By then, producing pure heat becomes more cost-effective.

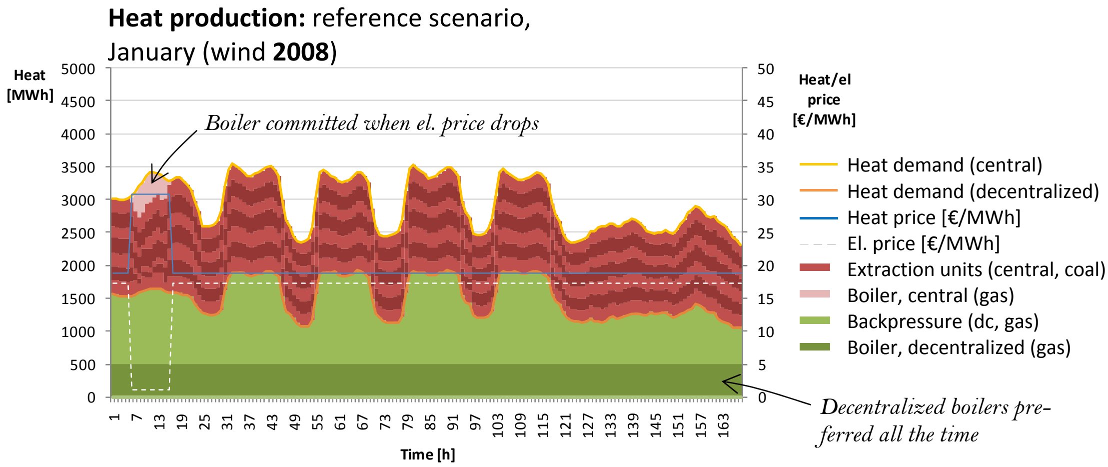


Figure 6.30, Plot of the heat production in the reference scenario first week of January, subjected to the 2008wind capacity. At the current price levels, extraction units (red) are dominating heat production in the central areas, whereas boilers in decentralized areas the entire time operates at maximum limit.

Figure 6.31 below, which represents a plot of the reference scenario subjected to the 2017 wind profile, shows an increasment of the tendencies seen in the 2008-reference scenario, due to the enhanced wind production.

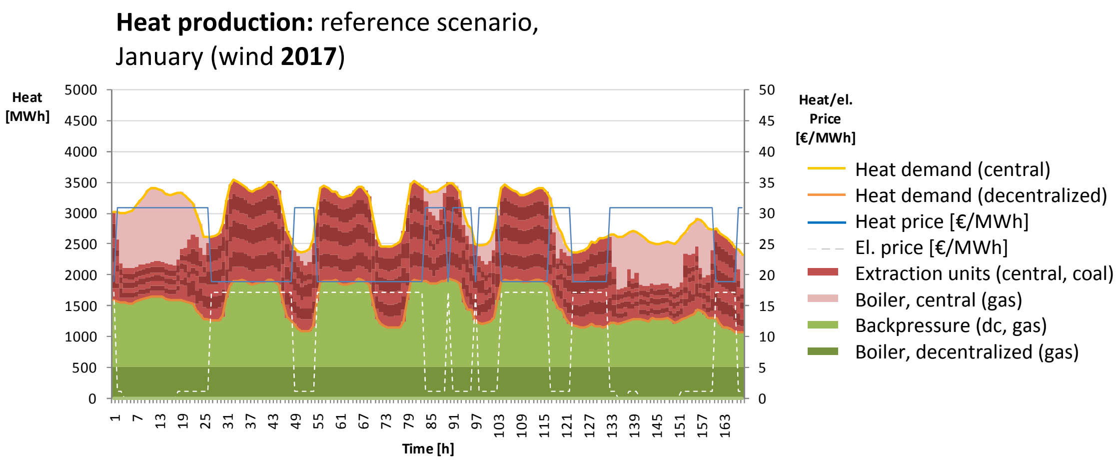


Figure 6.31, Plot of the heat production in the reference scenario first week of January, subjected to the 2017-wind capacity. The plot shows the same optimal composition regarding the producing alternatives as in the 2008-reference scenario, but with more frequent cases of central boiler capacities replacing a part of the extraction unit's supply.

Continuingly up-scaling the wind production to the more extreme 2025-reference scenario, it is seen in Figure 6.32 below, that the heat-production patterns changes additionally. The scenario is mainly characterized is a complete down regulation of extraction units in the periods with critically low electricity prices – and for some periods even with a complete de-commitment of these (except for the last three units committed by agreement). But then again, in some of the peak periods, production from extraction units increases to fully supplying the demand. What is particularly interesting here, is the *level of* down-regulation in the different low-price periods, which varies depending on the length of the period with low price.

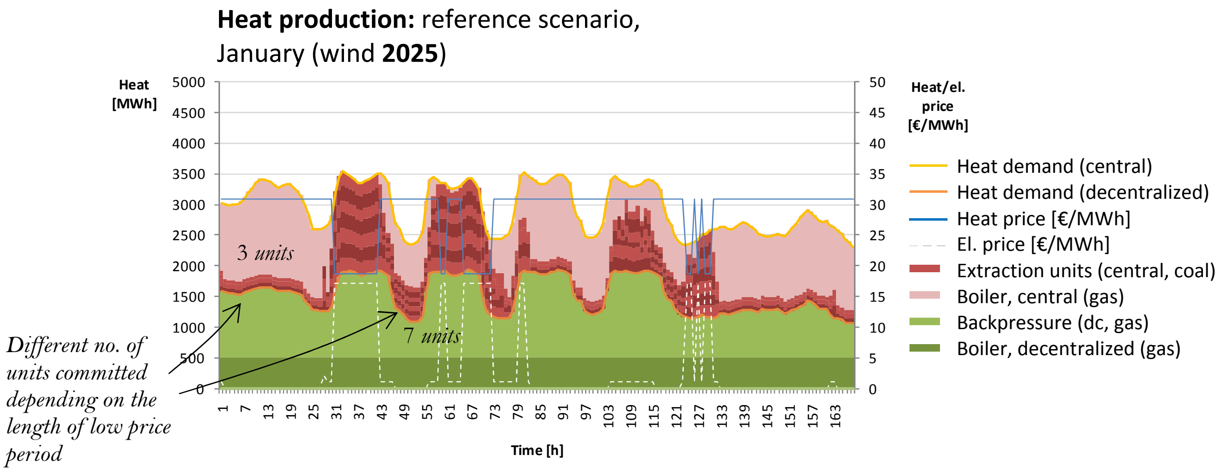


Figure 6.32, Plot of heat production in reference scenario first week of January, subjected to the 2025-wind capacity. A result of the increased amount of hours with zero-prices, in some periods only three units are committed c.f. the reserve capacity.

The bars seen in Figure 6.33 below indicate the total heat production over the entire year of the reference system subjected to the three wind capacities. The only real development towards the 2025 scenario is an increased production from boilers in the central distribution areas. The reason why the changing production patterns – just shown in the three figures above – is not repeated in the same degree when comparing the production patterns over the year, is that the January sample (as mentioned earlier) is quit extreme, and that the variation evens out when looking at the entire year. Finally, it can be concluded from this that the strongly increasing wind capacities, approaching 2025, has significantly little impact on the heat production patters – on an annual basis.

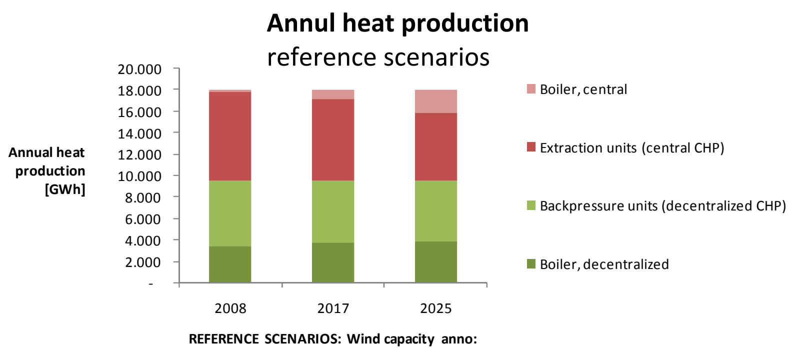


Figure 6.33, Comparison of total heat production in the three wind scenarios. The three wind scenarios do not vary considerably.

When looking at the production patterns in the hours with critically low prices, the bars in Figure 6.34 below show, that within these particular hours, heat production from extraction units is gradually reduced while heat production from boilers increases, as the wind capacity increases, thus reducing the basis of constrained electricity from central units (cf. the earlier on shown difference between the amount of generated electricity from central units in the in the model and the real system, Figure 6.20).

In the decentralized area however, boiling capacity is (again) constant during all three wind scenarios. What is interesting about the decentralized heat production, though, is that it all in all decreases on average as the wind capacity increases (towards the 2025 scenario), meaning that cold periods to a lesser degree is an explanatory factor for prevalence of critical prices in 2025 than today.

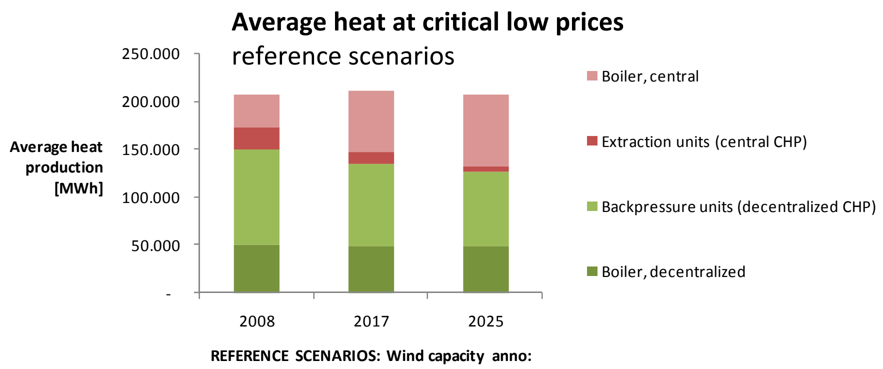


Figure 6.34, A comparison of the average heat production within critically low prices, showing an increased reduction in heat from extraction units due to increased heat from boilers.

The boiler capacity in the central and decentralized distribution areas is not alike. Where the central areas have enough capacity to cover any given heat demand, the decentralized areas have been modeled with just a part of the necessary capacity for doing the same. In the central area, heat production from boilers (gas) are only preferred over extracted heat when the electricity price is very low, whereas boilers in the decentralized area optimal most of the time. The chosen decentralized boiler capacity have been selected in order to imitate the amount of forced electricity observed in West-DK, since, theoretically, the decentralized boiler production would almost completely dominate the heat supply. As evidence of this, a modeled system with sufficient boiler capacity in the central areas, results in a much lower amount of forced electricity generation, than observed in West-DK, too. This is something that perhaps should have been considered when building the model, despite of the project’s objective of modeling a comparable, but not perfect approximation, of the West-DK energy system.

Heat production in bypass scenario

The optimized results of the heat production in the full-scale bypass scenario (modeled for a couple of weeks), as well as the single-unit bypass scenario (modeled for the entire year), will be presented in the fallowing. First, the impacts of the full-scale BPO scenario, under the influence of the windy profile (similar to Jan 2025), is shown in Figure 6.35 below. When comparing the optimized results of the full scale BPO system with the 2025 reference scenario it is seen that – contrary to the reference scenario – where almost a complete down-regulation of heat production from extraction units toke place, almost the entire heat production in the BPO scenario *is now produced on extraction units*. This also means that the production from gas fueled boilers is very low. And as seen previously, the bypass-system also maintains the heat-price at the low, steady level, corresponding more to the marginal costs of extraction units than of boiler, as well as the electricity price indicating a reduced incidence of electrical overflow. All in all, BPO seems to have a positive effect on the production patterns. If this is just as positive for the market and plant economy as well will be analyzed later in chapter 7.

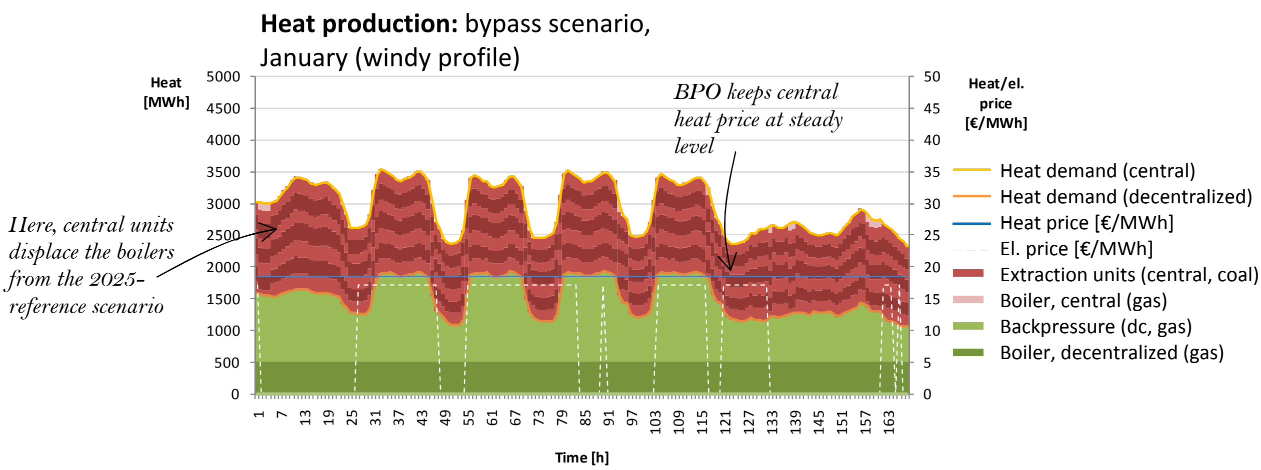


Figure 6.35, Plot of heat production in bypass scenario (first week of January), subjected to the windy profile, showing an almost complete outperformance of boiling capacity, despite of regularly critical low prices.

In section 6.2 on the price formation of the heat- and electricity price, we saw how a kind of "heat market error" occurred in some of the hours with critically low electricity price, resulting in an oversupply of heat (a limit of the Benson-minimum of boilers exceeding the demand). Now, due to this oversupply, the heat-shadow would price drops to zero, reflecting the marginal change in heat demand being costless. In Figure 6.36 below (showing a plot of the first week of November applied to the windy profile) an example is seen of an overproduction of heat, resulting in a corresponding zero-shadow price on heat. As mentioned earlier, this makes it harder to determine the value of heat on the basis of the model results of the BPO scenario. In a real heat market it is likely to be avoided.

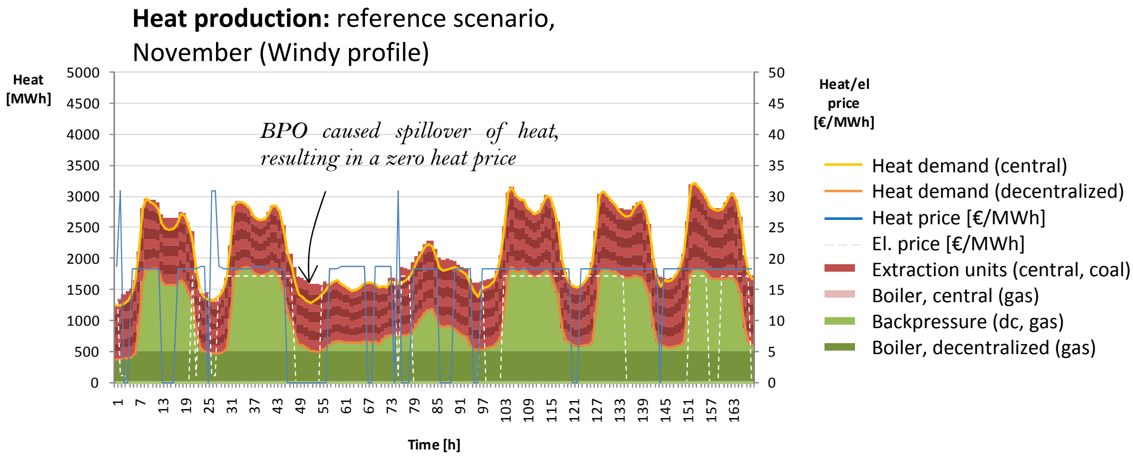


Figure 6.36, Plot of heat production in bypass scenario (November), subjected to the windy profile. Note here, that electrical spillover sometimes causes an additional spillover of heat, resulting in both prices to simultaneously dropping to zero.

A comparison of the average heat productions in the observed weeks of the BPO and the reference scenario is shown in Figure 6.37 below. Besides the variations in average heat production (a result of the different times of the year), it is seen from the BPO scenarios, that virtually no heat is produced on the central boiling units, on average in all three months. And again, we see decentralized boiler production being constant in all periods of the scenarios since generally being prioritized in the optimization.

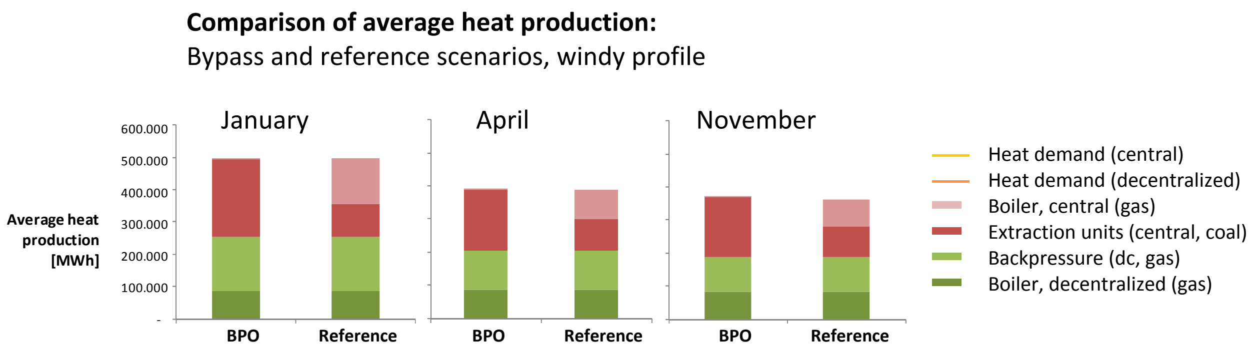


Figure 6.37, Comparison of average production in Bypass and Reference scenario by different producers, with windy profile applied to three different weeks from Jan, Apr and Nov, respectively. The most significant difference here is the lack of boiler-production in the BPO scenario in all three periods.

As mentioned earlier, the model only manages to generate feasible solutions of the full-scale bypass scenario with a relatively low accuracy, and the heat production is therefore also modeled as a single-unit bypass scenario. In Figure 6.38 below a comparison of the total heat productions of the single-unit bypass scenario (modeled for the entire year) subjected to the 2008, 2017 and 2025 wind profiles is shown. As seen in the here, practically none of the electricity produced in the BPO scenario is produced by boiler units like in the reference scenario where, on the contrary, boiler power increases towards 2025. It is furthermore seen, that in the BPO scenario the mentioned surplus heat increases approaching 2025. Finally, the figures recalls that the heat shadow prices in the reference scenario increases from an average of ~15 to ~17 € per MW heat, as a result of the increasing wind capacity, while this price in the PBO scenario remains constant around 11-12 € per MWh on average. Although these lower heat prices, seen in the BPO scenario, not necessarily represent the total economy of the particular heat system, they somehow reflect an improved system economy, which will be further analyzed in chapter 7.

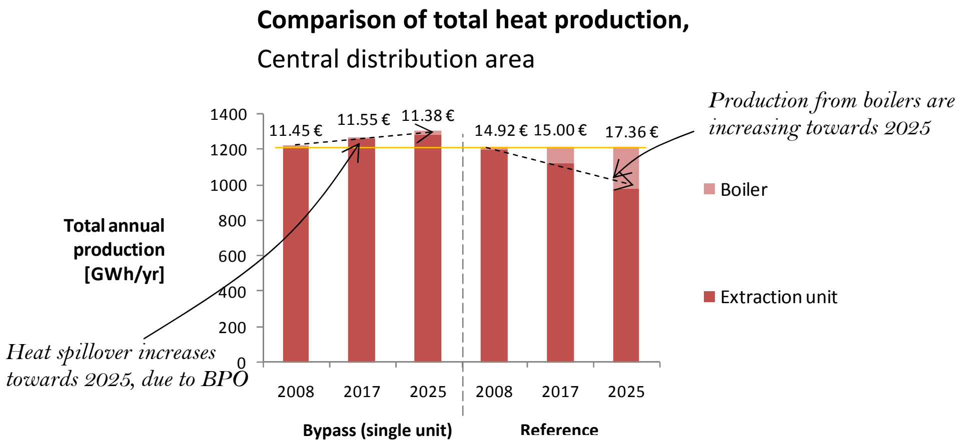


Figure 6.38, Comparison of the total heat production in a central distribution area for the Bypass and reference scenarios, respectively. Also, the average heat price is displayed.

Heat production in the heat pump-scenario

In this section, the optimized results of the heat production in the heat-pump scenario will be presented (in the same manner as in the previous two sections). The heat production patterns in the heat pump system subjected to the 2008 wind scenario are seen in Figure 6.39. Recalling the installed capacities being 350 MW and 500 MW for central and decentralized heat areas, respectively, the upper, dark blue area indicates heat-production from central pumps, and the lower blue area, indicates heat production from decentralized pumps. As seen in the figure, the most significant characteristics of the production pattern in the figure are: 1) that heat pumps in the decentralized area are sole producer of heat most of the time, outperforming both CHP units and boiling capacity (due to better variable production cost), and 2) that heat pumps are more economically optimal as heat producers during bank holidays than weekdays (the first 24 plus the last 48 hours of the sample). The reason for 2) is that the extracted heat more becomes a cheap “waste-product”, as a result of increased electricity demand. Regarding the overall production pattern, the results of the optimization indicates a more balanced interplay between the utilities in the central area than in the decentralized area. Furthermore, when looking at the heat pump scenario, for the first time the electricity price is high enough to give backpressure units an advantage over boilers in the decentralized area – meaning that backpressure units are more economic as heat producers when cogenerating.

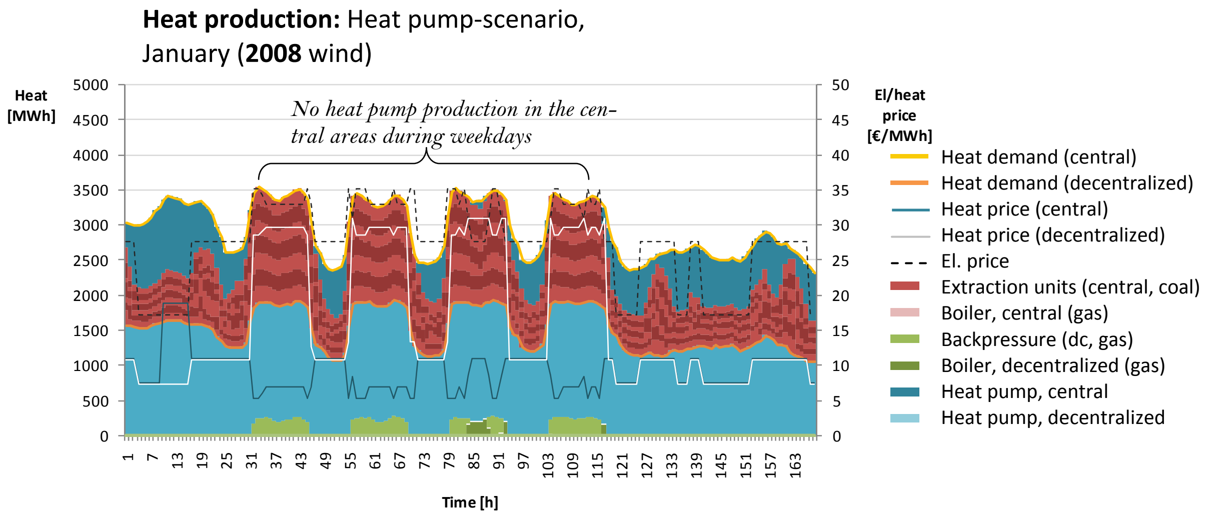


Figure 6.39, Plot of heat production in heat pump-scenario, first week of January, subjected to the 2008 wind capacity. Where heat pumps constantly dominate the decentralized heat area, the optimal production alternately varies between CHP and heat pumps. Additionally, no central boiler production is seen within the observed week and correspondingly just a little in the decentralized area.

In the fallowing figure, the resulting production patterns of the heat pump system subjected to the 2017 wind capacity are shown. Since decentralized pumps already operates on maximum level even at lover wind capacities, the only development in the production pattern from the 2008 to the 2017 wind scenario is an increased production from heat pumps in the central area at the expense of the production from CHP units. The reason, is that the higher wind penetration, causing a lower electricity price, has a positive impact on the heat pump's marginal production costs. Still, extraction units are mostly cheapest within daily peaks.

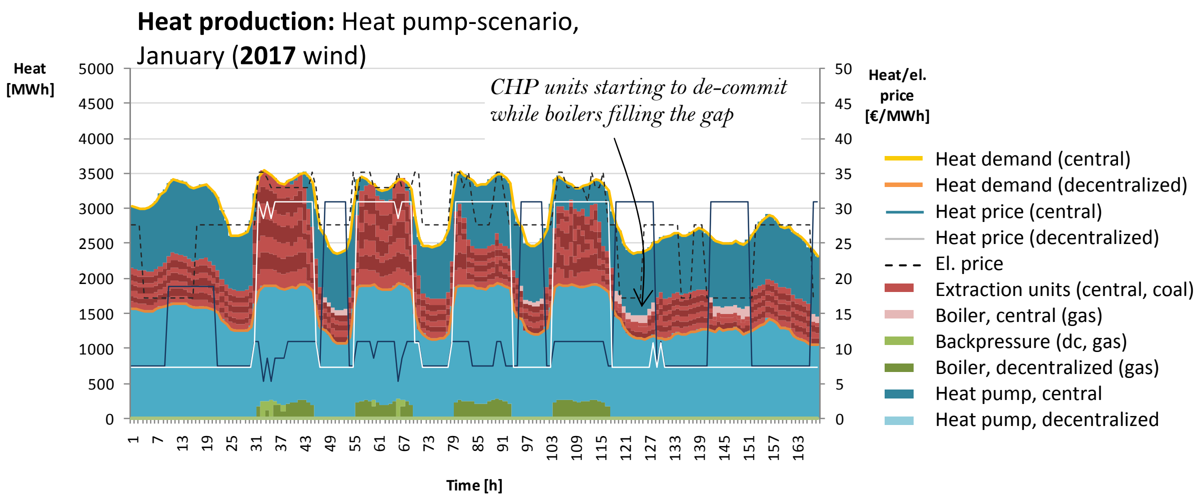


Figure 6.40, Plot of heat-production patterns in the heat pump-scenario subjected to the 2017 wind capacity, first week of January. Shows an unchanged operational situation in decentralized heat areas (compared to 2008), and increased HP production in the central

areas. In low consumption periods, the el. price additionally drops, causing extraction units to de-commit for a period, while boilers fill out the gab.

As the wind capacity increases further (into the 2025 wind scenario) it is seen in Figure 6.41, that the CHP units starts operating at minimum heat output – not only between the daily peaks, but *during* the daily peaks as well. Furthermore, we see the reserve capacity restriction ("the last three units") constraining the system more frequently.

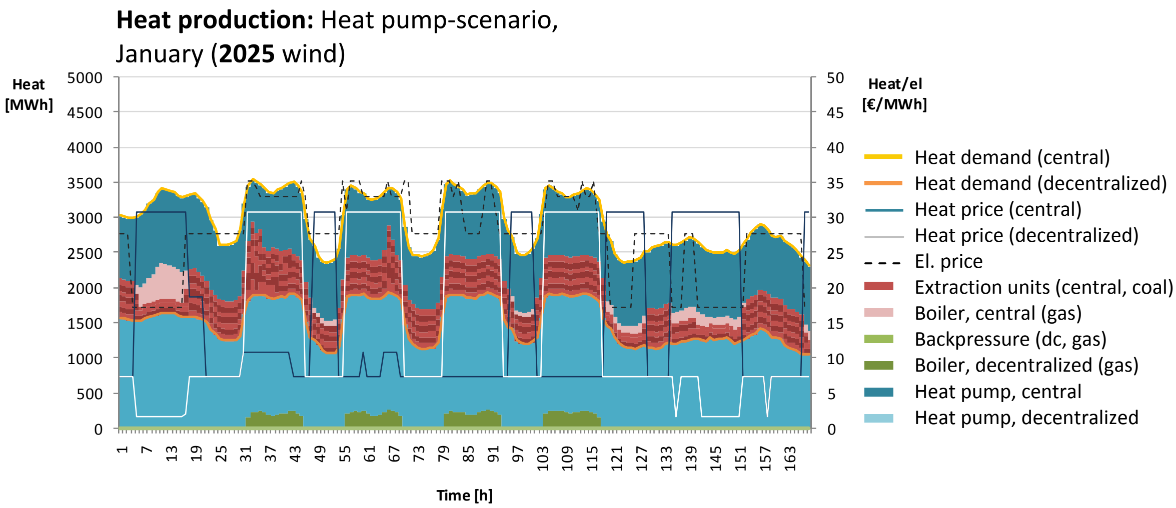


Figure 6.41, Plot of the optimized heat pump scenario subjected to the 2025-wind capacity. Here, production from extraction units is further lowered and more often being shut down compared to 2017.

The three figures above illustrate the heat pump scenario, when subjected to the increasing wind capacities towards the 2025 scenario. However, all three figures show samples from the first week of January, which (by coincidence) is a rather extreme week regarding both wind capacity and heat demand (the above average heat demand is of course predictable). Therefore, in order to get a better insight into the general production patterns of the heat pumps, Figure 6.42 below compares the total heat production throughout the entire modeled year (in the same way as with the reference and the bypass scenario).

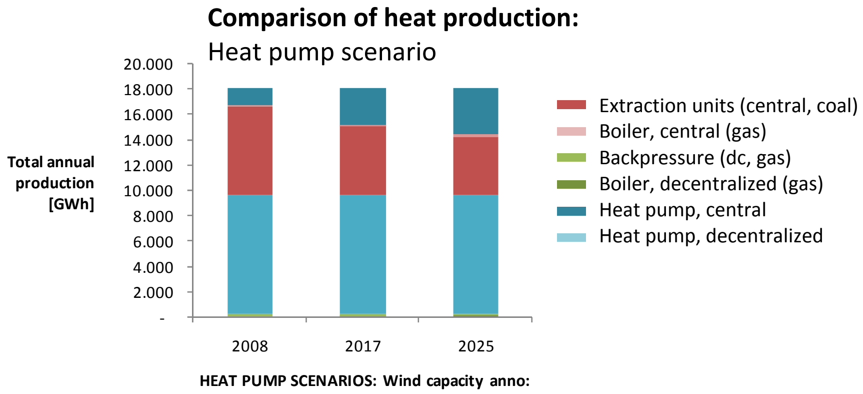


Figure 6.42, Comparison of heat production from the different facilities, showing a significant overweight of heat produced on electrical heat pumps, and decentralized CHP being non-prioritized.

When seen over the years modeled (figure above), heat produced on heat pumps make up a large share of the total amount of heat produced in the decentralized areas, regardless of the amount of wind capacity (meaning both in the 2008, the 2017 and the 2025 scenario). In the central distribution areas heat pumps have a smaller, yet increasingly, share of the produced heat towards the 2025 scenario. For heat pumps installed in central distribution areas, the key issue is the electricity price. The shadow price of heat pump follows the electricity price, which is opposite to extracted heat, whose price *increases* when the electricity price is low. When electricity prices are high, we see heat from extraction units replacing heat from heat-pump (this usually happens in periods of peak load).

Because heat pumps enhance the electricity demand they also contribute to higher shadow prices on electricity, which again, results in higher production costs for heat pumps. However, recalling that the annual heat production (indicated by the bars in Figure 6.42), is influenced by a constant, low marginal price on hydro power, the heat pump production in the central areas might be too high. Despite of this, the overall knowledge gained from the model result is that it would make the most sense economically to prioritize installation of heat pumps in the decentralized areas, since the results shows a greater utilization of the installed capacities.

6.3.3. Summary

Not only will the electricity- and heat prices change as consequence of increased wind capacity in the Danish energy system. In relation to this, the production patterns will be affected too. In this section, the results of the optimized production patterns on both electricity and heat production have been analyzed.

Regarding the production of electricity, it has been shown, that in the reference scenario, as a result of the increasing wind capacity, the extraction units down-regulates at first (2017 scenario) for then finally to de-commit to the absolute minimum as the wind capacity increases further (2025 scenario). Simultaneously, the quantity of exported power as well as the surplus wind capacity increases. However, the amount of wind power in the 2008 scenario seemed overestimated when compared to the average amount in West-DK 2004-2009, and additionally, the marginal costs of hydro (import) were underestimated, resulting in a much higher annual import than in West-DK.

When analyzing the hours with critically low electricity prices, it is shown that these prices occur during hours with increasing demands, as a result of the increasing wind capacity, and so do the amount of spilled wind production. The result of the optimization varies a bit from the real data though, in that the modeled central units was found responding too well to low prices compared to the West-DK 2004-2009 production. The level of export, observed in the hours of critically low prices, is higher in the model than in West-DK as well, which could indicate a worse management of congestions in the real system.

When it comes to electricity production in the bypass scenario, it was shown, that in a cold month like January, switching to bypass mode is generally more attractive than co-generation (in the windy 2025 scenario), whereas co-generation can be more efficient in November. Compared to the reference scenario, it was shown that the greatest difference on a total basis is the reduced exported power in the BPO scenario. Last but not least it was argued, that the bypass system is suitable for cold and windy times.

With regard to the heat pump scenario, this system differs from the reference scenario in that the decentralized power generation almost is completely superseded from the optimized heat- and electricity production, plus electricity production from condensing units suddenly takes place. This give rise to full internal utilization of wind power (which have displaced a great part of the power generation from extraction units), negligible electricity generation from decentralized units, "full steam" on condensing units during daily peaks, a great amount of import and increased electricity consumption from the electrical heat pumps. When subjected to the 2017 and 2025 wind scenarios, it is shown, that the power generation from extraction units decreases further, and in 2025 electrical spillover occurs even within the low consumption periods. Finally it is shown, that heat pumps with a COP value of 300 % efficiency are the most economic variable alternative out of the producing alternatives as long as hydro or wind power represent the marginal utility.

Overall, the production patterns regarding electricity, changes significantly as the wind capacity increases, almost eliminating power generation from centralized extraction units in the reference scenario as well as in the bypass system, and from decentralized units in the heat pump scenario.

When it comes to the production of heat, it has been shown that in the 2008-reference scenario, heat produced on extraction units is the most economic option - excepts when the electricity price drops to a critically low level. As the wind capacity increases this picture reinforces, and in the 2025-reference scenario a complete down-regulation – and in some periods even a complete de-commitment – of extraction units occur in the periods with critically low prices. At least this is the case when looking at the three January samples. The January samples are quite extreme though, regarding the level of both wind capacity and heat demand, and when looking at the average over the years, the only real development as the wind capacity increases, is an increased production from boilers in the central distribution areas. However, when focusing solely on the hours with critically low price, it has been shown that the heat production from extraction units gradually decreases while production from boilers increases as the wind capacity increases. Simultaneously, the decentralized heat production decreases as a result of the increasing wind capacity, thus reducing the basis of constrained electricity from central units. The amount of forced electricity might be higher in reality though, since the amount of forced electricity observed in West-DK (2004-2009 on average) is higher.

Regarding the bypass scenario, it was shown that almost the entire heat production is produced on extraction units; but at the same time it was argued, that it is hard to determine the value of heat on the basis of the model result due to the overproduction-error. Furthermore it was shown, that compared to the reference scenario virtually no heat is produced on the central boiling units in the full-scale BPO scenarios. The same is the case in the modeled single-unit BPO system, where no heat is produced by boilers. This shows that extraction units are superior when being given the option of bypassing the power generation. Moreover it was shown that the surplus heat increases as the wind capacity is extended, but that the heat price remains at the same level – indicating an improved system economy in the BPO system compared to the reference system.

When it comes to the heat pump system, the significant characteristics of the 2008 system are: 1) heat pumps are sole producer of heat in the decentralized area more of the time, and 2) heat pumps are more economic optimal during bank holidays than weekdays and 3) the electricity price is often high enough to give backpressure units an advantage over boilers in the decentralized area (although their share of the heat produced is almost insignificant). When extending the wind capacity (anno 2017) it was shown that the only change in the production pattern is an increased production from heat pumps in the central area, at expense of the production from CHP units. When increasing the wind capacity further, the CHP units start operating at minimum heat output a greater share of the time, though, and the central units often de-commit down to the "last three standing". In all three scenarios, heat pumps make up the largest share of the total amount of the heat produced, and all in all it can be said, that it would make the most sense economically to prioritize installation of heat pumps.

As with the production patterns of the electricity production, the patterns of the heat production will change as a result of the increasing wind capacity too. If no further means are taken (c.f. the reference scenario) the production from extraction units will not only decrease, but in some periods completely down-regulate to the allowed minimum in the hours of critically low prices. The use of bypass might to some extend counteract this development, as almost the entire heat production is produced on extraction units, however, as the wind capacity increases, the amount of surplus heat increases. The modeled heat pump capacity manages quite well to counteract the described down regulation of extraction units (in favor of boiling units) to minimum capacity simply by increasing the shadow price on electricity. Of cause, if a long term goal would be to phase out coal power plants, heat pumps would not contribute in a positive direction.

Chapter 7.
Economic Analyses

7.1. Overview of the economic analyses

The Unit Commitment model is basically an economic optimization model designed to search for an optimal combination of a number of available utilities, given a set characteristics that can satisfy a number of demands at the lowest, total costs. Therefore the results presented in the previous chapter represent the most economically optimal output given the respective conditions – when seen from "the market's" point of view.

As mentioned earlier, this chapter will look at some of the economic aspects of the model results for further comparison of the different scenarios. The reason for this is to evaluate not only the economic consequences that implementation of wind capacity corresponding to 50 % wind power may result in, but also the potential of turbine bypass and heat pumps as tools for increased flexible production.

The economic analysis is divided into four parts. The first part is an analysis of the economic results, seen from the different types of producers' point of view, covering areas such as annual full load factors, turnover and profit. This is a particularly important part of the assessment and valuations of the turbine-bypass concept, meaning that, if this technical development will have a negative influence on the economy of the individual power plant, it might not be a feasible economic solution even though it is considered positive from a socio-economic aspect. The second part is about the economic impacts of modeled constraints, as interpreted from shadow prices calculated from these constraints. The third part is an analyze of the total system economy including total system turnover, the rate of import/export, wind power utilization, bottleneck income, and finally, the fourth part is on green accounting, covering the costs of CO2 exhaustion from production. As in the previous chapter, in all four parts, the results of the modeled calculations will be analyzed for all three scenarios – reference, heat pump and bypass - subjected to the three wind profiles – 2008, 2017 and 2025, except for the full scale bypass operation which is modeled for one week for each of the seasons (January, April, June and November).

As mentioned in section 5.2.3, the following economic analysis will not cover the investment aspects since the mathematical model results are derived on basis of variable costs only. This being said, the model results provides a number of factors, such as annual load factors, profits, shadow prices on constrains etc., which could be considered in connected with the investment area too.

7.2. Single power plant economy

In this section, the economic characteristics of the different individual utilities will be analyzed in relation to the full load factors, the total hours of commitments, number of start-ups per week, and finally the total income and profit – all on the basis of one year. When analyzing the impact of these factors (subjected to the different wind profiles), focus will be on extraction units and condensing unit, due to the fact that both represent large and detailed economic characteristics, by which the direct consequences of the varying conditions will emerge more clearly.

7.2.1. Load factors (LF)

In this project, the definition of load factor, or *full-load factor*, is the average production capacity divided by the maximum production capacity over a given time period – in this case a year. In energy systems, load factors are often used in connection with calculations of depreciations as well as potential profits for long term investments in energy producing facilities. Thus, expecting a certain price (or price duration) within the depreciation period, the estimated full load factor indirectly indicates the expected turnover. For extraction units, the maximum capacity used to calculate the *electrical* full load factor is within condensing mode. The maximum capacity used for the *CHP* load factor however, is the maximum, total heat and electricity output possible.

Table 7.1 below contains the modeled *electrical* load factors (%) for each of the central power units of the system. The extractions units are represented by the units G1-7, while G8 and G9 represents the condensing units. Starting with the impact of the three wind scenarios on the electric load factors of the reference scenario, the electrical load factors of the extraction units are characterized by a decrease in annual power generation from 2008 to 2025 ranging from a 9 percentage points decrease (G1), to just a 4 percentage points decrease (G3). All in all the electricity generation decreases from approximately 10 to 8 TWh. In the bypass scenario, the annual electricity generation goes from 20 % of full load to 10 % (in both 2017 and 2025) for G1, indicating, that it is half as attractive to generate power, compared to cogeneration in 2017 and 2025 as in 2008. The impacts on the rest of the units in the single-unit bypass scenario are rather insignificant compared to the reference scenario, and deserves no further analysis.

The total electricity generation in the heat pump scenario goes from approximately 9 TWh to 5 TWh, towards 2025. The electricity load factors of extraction units are generally falling compared to the reference scenario, indicating limited conditions for optimizing profit. However, due to the increased electricity demand of the heat-pump system, the *condensing units* now changes from functioning as peak load capacity in the reference and bypass scenario (with around a silly 1 % load factor), to operating as medium and base load plants in the heat pump scenario (with load factors of 30 % and 35 % in 2008, respectively, to 10-20 % in 2025). Thereby, it can be said that the heat-pump scenario results in better conditions for condensing electricity.

Load factors (el.) [%]		Extraction units							Condensing units		
SCENARIOS:	Central unit:	**G1**	**G2**	**G3**	**G4**	**G5**	**G6**	**G7**	**G8**	**G9**	**Total el. gen** [GWh el.]
	2008	28	32	31	30	34	29	27	0	3	10,238
Reference -	**2017**	25	30	29	27	31	25	24	0	1	9,317
	2025	19	27	27	22	28	20	19	0	1	8,281
	2008	**20**	31	31	31	33	29	27	0	1	9,867
Bypass, single unit (G1)	**2017**	**10**	30	29	27	31	26	23	0	1	8,796
	2025	**10**	26	26	22	28	19	18	0	1	7,789
	2008	27	32	31	28	34	26	24	35	30	8,968
Heat pump -	**2017**	19	25	25	20	28	19	17	25	18	6,459
	2025	15	22	21	16	25	15	14	21	12	5190

Table 7.1, Comparison of electrical load factors for centralized units.

The total income of a CHP plant includes the heat production too. The modeled *CHP* load factors are therefore shown in Table 7.2 below. The CHP load factors are in general a bit higher than the electrical load factors seen above. They decrease with approximately the same rate, though, which could be a symptom of the power generation being constrained by the heat demand. When looking at the bypass scenario and comparing the CHP LF to the electricity LF for G1, it is seen, that the decrease in LF, approaching 2025, is much smaller for the combined heat and electricity production (from 28 to 24 %) than for just the electricity production. This means that the heat production remains almost intact in the bypass scenario. Other than that, the two load factors seem coupled to each other when comparing the scenarios.

Load factors (CHP) [%]		Extraction units							
SCENARIOS:	Central unit:	**G1**	**G2**	**G3**	**G4**	**G5**	**G6**	**G7**	**Total CHP** [GWh]
	2008	32	36	36	35	39	33	31	24,641
Reference -	**2017**	29	34	34	31	36	29	28	22,636
	2025	22	31	31	25	33	23	22	20,293
	2008	**28**	36	36	35	38	33	31	24,316
Bypass, single unit (G1)	**2017**	**24**	34	34	31	36	30	27	22,347
	2025	**24**	30	29	25	33	22	20	20,078
	2008	28	34	33	31	36	29	27	16,244
Heat pump -	**2017**	21	28	27	23	30	21	19	12,159
	2025	16	25	23	18	28	17	16	9,937

Table 7.2, Comparison of CHP load factors for centralized units.

Following up on the bypass scenario, Table 7.3 below compares the calculated electricity- and CHP load factors of the reference and the full-scale bypass scenarios subjected to the windy profile (weekly sample). It is seen that, while the electricity LF of the BPO scenario sometimes is 3-4 times smaller than in the reference scenario, the total CHP LF generally is higher in the BPO scenario than in the reference scenario. When disregarding the particular heat and electricity prices of the given week, the numbers c*ould indicate a potential improvement of the power plant economy if converting into BPO* – in windy periods though.

***Full load factor (el. and CHP)* [%]**		**Central Extraction units**							
SYSTEM SCENARIOS:	**load factor**	**G1**	**G2**	**G3**	**G4**	**G5**	**G6**	**G7**	**Total** [GWh]
Reference -	Electricity	9	23	22	11	23	10	9	476
	CHP	11	26	24	13	26	12	10	1203
Bypass, full scale	Electricity	6	6	6	6	3	7	4	326
	CHP	21	23	24	23	23	23	19	1390

Table 7.3, Comparison of electricity- and CHP load-factors for central units.

7.2.2. Commitment factors

The reason that some units (as seen in the previous section) experience a smaller decrease in annual production than others is often due to the reserve capacity constraint of the unit commitment model. This is for example seen for the extraction units G2, G3 and G5 of the reference scenario in Table 7.4 below, showing the annual commitment factors. By commitment factor is understood the percentage of an observed period where the particular unit is committed. In the bypass scenario, the single unit with optional BPO (G1) is among the three most favorable[30] regarding the commitment factor, whereas it was the least favorable regarding the load factor. The reason why the model tends to choose G2, G3 and G5 for constant commitment over the modeled year is simply because they have the lowest minimum production capacities of the extraction units (see Table 5.6, chapter 5), resulting in the lowest possible production at the times where the constraint causes forced production. Moreover, the table shows that, for the rest of the units, lowering production becomes a more and more used towards 2025, going from a commitment of 86-96 % to 63-73% in both the reference and the heat-pump scenario. However, what is interesting here, is that the decrease in annual commitment in the reference scenario is smaller when going from the 2008 to the 2017 wind capacity (96 % of the average 2008 commitment level), than when going from the 2017 to the 2025 wind capacity (85 % of 2008). This means, that the annual commitment factor is less influenced by the first step of the 2017-wind extension, than by the further extension to the 2025 scenario. Furthermore, it is seen that the largest decrease in commitment is in the heat-pump scenario.

[30] Assuming in the model that BPO does not compromise the reserve capacity criteria

Annual Commitment [%]		Extraction units							Condensing units		
SCENARIOS:	Centralized units:	**G1**	**G2**	**G3**	**G4**	**G5**	**G6**	**G7**	**G8**	**G9**	**Average**
Reference -	*2008*	91	**100**	**100**	96	**100**	94	91	0	6	75
	2017	85	**100**	**100**	89	**100**	87	86	0	3	72
	2025	67	**100**	**100**	73	**100**	71	66	0	2	64
Bypass, single unit (G1)	*2008*	**100**	98	98	95	96	93	86	0	2	74
	2017	**99**	98	95	89	100	88	78	0	2	72
	2025	**99**	91	89	73	100	67	63	0	1	65
Heat pump -	*2008*	79	98	96	88	100	85	76	48	40	79
	2017	62	90	90	69	100	66	57	48	24	67
	2025	50	88	81	57	100	55	48	50	17	61

Table 7.4, Comparison of commitment factors for centralized units.

To elaborate on the commitment factors in the bypass scenario, the full scale version is seen in Table 7.5 below (calculated in accordance with the windy weeks). As it appears, applying the option of BPO to all units results in a much greater commitment factor (91 % in the BPO scenario compared to the 62 % in the reference scenario). This means, that if any technical or economical factors are dependent on a large commitment factor, BPO could be applied with advantage.

Average commitment [%]	Central Extraction units (coal)							
SYSTEM SCENARIOS \ units:	**G1**	**G2**	**G3**	**G4**	**G5**	**G6**	**G7**	**Average**
Reference -	36	100	95	36	100	35	32	**62**
Bypass, full scale	87	96	98	95	84	99	75	**91**

Table 7.5, Comparison of commitment factors for central units in the full-scale BPO and reference system, modeled over the three different week-samples (windy profile).

7.2.3. Number of start-ups

It has been said, that one of the things that concerns power plant operators the most (economical as well as technically), is the start-up and shut-down issue. It is therefore of interest to explore how the application of BPO affects the number of start-ups. Table 7.6 below shows the average number of start-ups per week. It is seen here, that in the reference scenario (as well as in the heat pump scenario), the number of start-ups per week generally increases as the wind capacity increases, going from an average of 0.59 weekly start-ups in 2008 to 0.81 weekly start-ups in 2025. This, however, does not include the three units constrained by the reserve capacity-restriction, due to being committed the entire modeled year. Regarding the unit with applied bypass (G1), the number of start-ups is 0.4[31] per week, which, compared to the 1-1.5 per week in the reference scenario, might be of interest of worried plant operators. A part of this decline can be explained by the increased commitment factor due to the BPO (as seen above in Table 7.5). Finally, the system scenario resulting in the highest number of start-ups is the heat-pump scenario, where some of the extraction units have around three start-ups per week.

No. of start-ups per week		Extraction units							Condensing units		
SYSTEM SCENARIOS:	Central units:	**G1**	**G2**	**G3**	**G4**	**G5**	**G6**	**G7**	**G8**	**G9**	**Average**
	2008	1.02	0.23	0.23	0.75	0.23	0.87	1.04	0.08	0.85	**0.59**
Reference -	*2017*	1.12	0.23	0.23	0.98	0.23	1.10	1.19	0.00	0.40	**0.61**
	2025	1.50	0.23	0.23	1.54	0.23	1.54	1.69	0.04	0.29	**0.81**
	2008	**0.44**	0.46	0.40	0.88	0.23	0.87	0.98	0.00	0.23	**0.50**
Bypass, single unit (G1)	*2017*	**0.44**	0.38	0.62	1.06	0.23	1.04	1.19	0.00	0.29	**0.58**
	2025	**0.42**	0.69	0.69	1.56	0.23	1.54	1.56	0.00	0.25	**0.77**
	2008	2.88	0.37	0.56	1.94	0.23	2.50	2.77	2.73	5.88	**2.21**
Heat pump -	*2017*	3.17	0.77	0.65	2.96	0.23	3.12	2.83	2.02	4.00	**2.19**
	2025	3.00	0.73	1.08	3.10	0.23	3.06	2.71	1.50	2.87	**2.03**

Table 7.6, Comparison of the weekly number of start-up for central units in the different scenarios and wind profiles, modeled over a year.

As mentioned above, the number of start-ups (and hence switch-offs) can be an important factor. However, with the assumed start-up costs of 1,323 € (10,000 Dkk), the maximum amount of startup annual cost calculated within the modeled scenarios, has turned out to be just below one percentage of the total income. With such relative insignificant influence on the total economy of power plants, it does not seem reasonable, from an economic perspective, to argue against a high number of startups, based on the model results.

Operating history of the bypass system

In order to get a deeper knowledge of the optimized on/off-combinations in the bypass system, when subjected to the increasing wind capacity towards 2025, and throughout the different periods of the year, the following is dedicated a further review of the bypass variable $b(i,t)$[32]. As explained in section 5.3.3, the bypass variable "decides" for each hour whether a fully bypass of the power generation is economical optimal or not, by assigning the values one or zero (one equalizing: "BPO is on"). In Figure 7.1 below a plot of the "on/off switching" of BPO in the full-scale bypass scenario subjected to the windy profile (~3000 MW average production) is shown. Each color represents one of the extraction units, and the layers with different colors thereby indicate whether or not bypass in each

[31] It is however worth noticing, that 0.23 weekly start-ups marks an absolute minimum by in practice being equal to zero start-ups, due to the model sequence being restarted every month (by which all the figures should be corrected).

[32] with i being the unit index, t the time index and b the binary variable (assuming 0 and 1)

of the seven extraction units is switched on. The white areas indicate conventional operation (bypass being switched 'off'). The corresponding wind and central heat demand is displayed to the right. Remembering, that the demands of the central heat distributions areas (black curve) in the model are scaled according to the upper (and lower) capacity limits of the connected extraction units, note, that the red lines indicate the lower heat capacity limit when operating in bypass mode (a direct consequence of the Benson minimum of boilers).

Of the things worth noticing from the figure is that, whereas BPO usual is assessed optimal in situations with high wind capacity and high heat demand, BPO is often also considered optimal in situations where the heat demand is *lower* than the minimum capacity of the extraction unit (notice some of the hours in April as well as November in Figure 7.1 below). The consequence being, as seen, that the heat production sometimes takes place although bypass is turned on, as result of a very low electricity price. This illustrates the BPO-caused overproduction described previously.

As a result of these factors, PBO is 'switched on' almost the entire time in the week-sample for January, whereas BPO only is 'on' about half of the time in the November sample. Note again that the wind production used for modeling these samples are the windy profile.

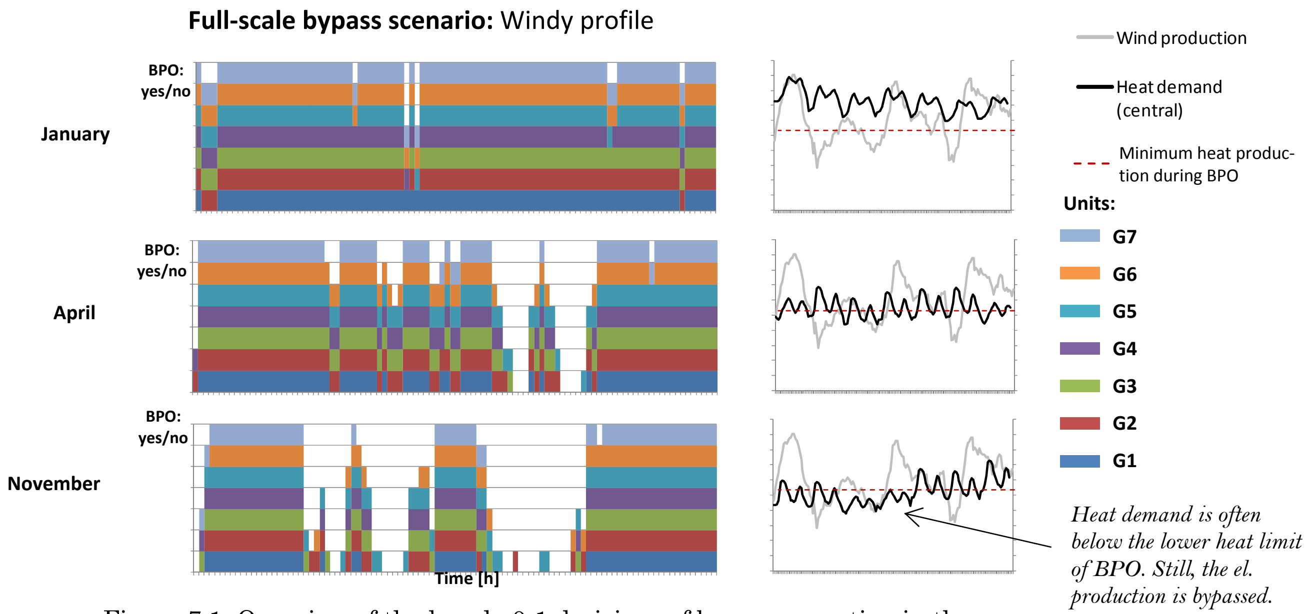


Figure 7.1, Overview of the hourly 0-1 decisions of bypass operation in the full-scale BPO scenario, one-week samples for January, April and November.

In addition to the full-scale BPO scenario, a scenario with BPO applied to a single unit has been modeled in order to fully study the BPO options made throughout the entire year when subjected to the increased wind capacities. In this way, it also becomes clear how often bypass operation is optimal given a smaller wind penetration, which is of interest in connection with the current West-DK system. Figure 7.2 below consists of three plots, each indicating whether or not BPO is on or off for each hour of an entire year when subjected to the 2008, 2017 and 2025 wind scenarios, respectively. As seen in the figure, electricity production is bypassed most of the time in April, February and November and all the time in December already when subjected to the 2008 wind capacity. When subjected to the 2017 wind capacity, January, March and September additionally become months with a high share of hours with BPO, and in July BPO is on in about one fifth of the time. Subjected to the wind capacity anno 2025, BPO-mode is swished on in all months – with the exception of June, and October

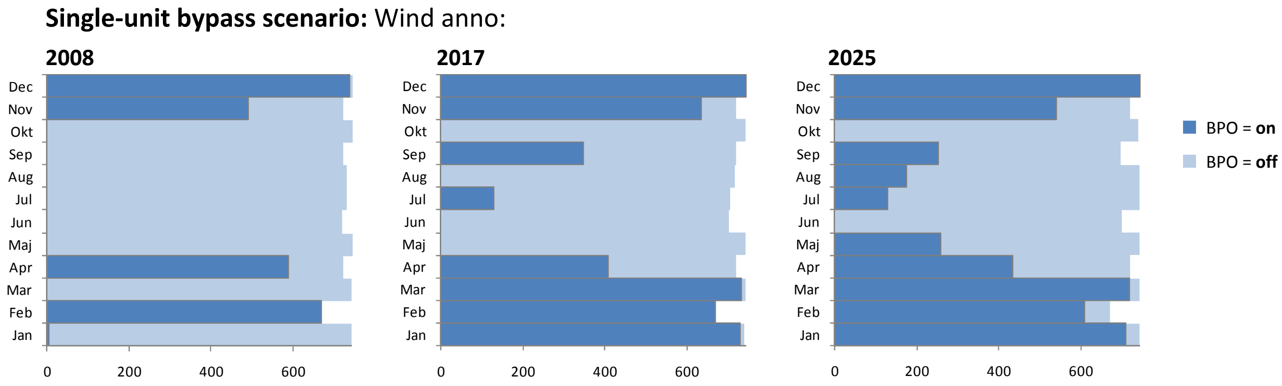


Figure 7.2, Comparison of the monthly on/off-behavior of BPO in the single-unit bypass scenario, subjected to the wind capacities of 2008, 2017 and 2025. Note that the heat demand is unchanged along with the extension of wind capacities.

Based on the fact that BPO sometimes is selected regardless of the heat demand being lower than the minimum heat production, the results seem promising in relation the economic potential of this, perhaps small, technical modification. What is more specifically meant here is that; it might be possible in the real system to avoid the minimum capacity limit that "holds back" the hourly choice of BPO, and in this way, to potentially reduce the heat-constrained power generation of the backpressure mode even further, than seen immediately from the results. Why? First of all, when remembering that the model in this project (for simplifications) does not include any kind of heat storing mechanisms (c.f. accumulation tanks) and thus is based on momentary balancing of production, there might be a great potential for avoiding production of surplus heat when taking these factors into account. Another way to avoid the limit without compromising the Benson minimum (perhaps a more technical approach), is to further explore the possibilities of *partial* heat bypass instead of full bypass as modeled in this project. Finally, one could argue that more research on the technical properties of boilers, might lead to new ways to extend the lower limit.

Based on these results and considerations, bypass operation has an economic potential as seen in the frequent use of BPO. In this connection the capacity issue just described, or the possibilities of avoiding this limit, will become another, interesting problem to be further examined – unless, of course, the problem can be resolved by the already present heat-accumulation tanks of the real system.

7.2.4. Total income of power units

Until now we have seen how the expansion of the wind capacity towards the 2025 wind-scenario causes a decrease in the annual load- and commitment factors for central units, as well as a small increase in the number of expected start-ups. When thinking of central power units as an autonomous economy – an economy which is often based on large investment that has to be depreciated by an expected amount of hours with full load – the observed load factors may affect this economy. However, the load factor alone will not determine the total income (and profit) of the operation, as the total income also depends on the particular price formations within the hours of load.

Table 7.7 compares the annual income of each central unit for the combined wind- and heat system scenarios, calculated for each hour of the year. The income, or revenue, is calculated as the produced heat and electricity production multiplied by the corresponding shadow prices. Starting with the reference scenario, it is seen that all central units will have reduced revenue as consequence of increased wind penetration as, some more than others. On an average, the income of these units decreases by almost one third, going from 30.04 to 21.85 million Euros per year. Condensing units account for just a small share of the total income.

In the bypass scenario, the annual income of the unit with applied bypass (G1) is lower than in the reference scenario. In addition to this, the reduction in the annual income from 2008 to 2017 is much greater (relatively) when compared to the reference scenario. The reason for this is first of all that the generator operates in BPO-mode much more frequently in 2017 than in 2008. As a result of this, the lower power generation additionally lowers the CHP production, which often determines the income. This however, does not fully explain the reduction. While the mentioned CHP-decrease from 2008 to 2017 is around 15 %, the similar reduction of the income (see below) corresponds to around 30%.

In Table 7.8, which shows the calculated profits, it is seen that the annual loss of income in 2017 is around 6.3 million Euros, which is much higher compared to the corresponding loss of around 2 million Euros in the reference scenario. Generally, the calculated negative profits seen in Table 7.8 are constraint-related and first of all connected with the minimum capacity limits of the central. When operating in bypass-mode, these revenue losses are often greater, because of a higher minimum heat limit (see explanation in section 7.2.3). The calculated incomes therefore sometimes appear smaller than they “in practice” would be, assuming that producers in a real system would avoid these specific market situations, by charging the necessary costs for an complete, economic coverage.

Annual ***income*** (Mill. € per year)		Extraction units							Condensing units		
SYSTEM SCENARIOS:	Central units:	**G1**	**G2**	**G3**	**G4**	**G5**	**G6**	**G7**	**G8**	**G9**	**Mean**
Reference -	**2008**	38.36	38.28	37.98	42.24	29.76	40.02	37.77	0.21	5.70	**30.04**
	2017	34.05	35.03	34.72	37.00	26.59	34.65	33.47	0.00	2.39	**26.43**
	2025	26.34	31.32	31.21	29.70	23.63	27.59	25.33	0.13	1.44	**21.85**
Bypass (applied to G1) -	**2008**	**34.04**	38.19	38.31	42.85	29.01	40.45	37.37	0.00	2.15	**29.15**
	2017	**24.98**	35.05	34.81	37.45	26.89	36.08	32.22	0.00	1.95	**25.49**
	2025	**23.23**	30.06	29.86	29.70	23.78	25.92	23.75	0.00	1.48	**20.86**
Heat pump -	**2008**	37.46	38.35	37.09	39.23	29.32	37.06	34.43	26.16	58.32	**37.49**
	2017	26.75	29.65	28.74	28.34	22.63	26.68	24.23	17.37	34.21	**26.51**

	2025	20.14	24.16	23.20	22.34	18.95	20.84	18.98	13.49	23.34	**20.60**

Table 7.7, Comparison of total income of central units in the different system- and wind scenarios.

Annual ***profit*** (Mill. € per year)		**Extraction units**							**Condensing units**		
SYSTEM SCENARIOS:	Central units:	**G1**	**G2**	**G3**	**G4**	**G5**	**G6**	**G7**	**G8**	**G9**	**Mean**
Reference	**2008**	-2.01	-2.18	-2.18	-2.07	-1.39	-2.07	-2.05	0.00	0.04	**-1.55**
	2017	-2.30	-2.90	-2.90	-2.38	-1.84	-2.40	-2.35	0.00	0.02	**-1.89**
	2025	-2.08	-3.49	-3.49	-2.19	-2.22	-2.13	-2.07	0.00	0.01	**-1.96**
Bypass (applied to G1)	**2008**	**-4.20**	-1.95	-1.93	-1.93	-1.36	-1.96	-1.62	0.00	0.03	**-1.66**
	2017	**-6.30**	-2.69	-2.37	-2.31	-1.85	-2.37	-1.87	0.00	0.02	**-2.19**
	2025	**-7.97**	-2.87	-2.79	-2.22	-2.25	-2.10	-2.06	0.00	0.02	**-2.47**
Heat pump	**2008**	-0.64	-1.61	-1.42	-0.99	-1.21	-0.88	-0.65	0.51	2.01	**-0.54**
	2017	-0.84	-2.55	-2.64	-1.06	-2.47	-0.97	-0.76	-0.92	1.12	**-1.23**
	2025	-0.93	-4.20	-3.30	-1.18	-3.75	-1.10	-0.99	-2.03	0.75	**-1.86**

Table 7.8, Comparison of annual profit of the central units, defined as the difference between the variable production costs and the corresponding shadow prices on heat and electricity. When calculating this way the profit usually is greater than or equal to zero. However, in some periods (especially in the summer) profit becomes negative due to both el. and heat shadow priced being lower than the production costs.

Remaining at the declining revenues of the single-unit bypass scenario (seen above) it would make sense to include the described losses (Table 7.8) in the revenues when estimating the producer's potential income, since no producers in practice would supply without coverage. In this way it is more likely that the income of the bypass unit would be 38, 31 and 31[33] million Euros in 2008, 2017 and 2025, respectively. Correspondingly, the income of the same unit in the reference scenario would annually be 40, 36 and 28 million Euros, and the immediate revenue loss from switching to bypass in 2008 and 2017 would not be as big as it appeared at first. In 2025 the income of the bypassed unit would even be approximately 3 million Euros higher than in the reference scenario.

A comparison of the calculated costs, income and profits of the one-week-sample *full scale* bypass scenario, as well as of the reference scenario (both subjected to the windy profile), is reported in Table 7.9 below. As it appears from the table, the average incomes of the reference and the bypass scenario (calculated by multiplication of hourly production and shadow price), are almost the same. However, a large amount of negative profit in the bypass scenario is found here too. As above, the negative profits are assumed errors from a constrained market, and the production costs are therefore considered a more correct indicator of the income. The average cost of the bypass and the reference scenarios are 1.5 and 2 million Euros, respectively, which means that extraction units in the bypass scenario is more productive. Another interesting characteristic is that the total income is more evenly distributed on the producing units in the bypass scenario than in the reference scenario. This indicates that the units usually being "the last three" representing the reserve capacity (G2, G3 and G5) will have a smaller income in

[33] The 'new' income is calculated as the annual income plus the inverse annual profit, e.g. 2008: 34.04 + 4.20 = 38.24

the bypass scenario than in the reference scenario, while the other units will have a higher income.

Annual ***income*** (Mill. € per year)		Extraction units							
Annual income		**G1**	**G2**	**G3**	**G4**	**G5**	**G6**	**G7**	**MEAN**
Income	**Bypass**	1.33	1.50	1.51	1.63	1.24	1.52	1.32	**1.44**
	Reference	1.04	1.88	1.78	1.23	1.39	1.13	0.98	**1.35**
Profit	**Bypass**	-0.72	-0.54	-0.57	-0.68	-0.15	-0.80	-0.52	**-0.57**
	Reference	-0.01	-0.33	-0.33	0.00	-0.24	0.00	0.00	**-0.13**
Production costs	**Bypass**	2.05	2.04	2.08	2.31	1.40	2.32	1.84	**2.01**
	Reference	1.05	2.21	2.11	1.23	1.62	1.13	0.98	**1.48**

Table 7.9, Comparison of total production costs, income and profit of the central units, in the week-samples of the full-scale BPO and reference scenario, subjected to the windy profile.

When subjected to the 2008 wind capacity, the inclusion of heat pump does not affect the income level of extraction units when compared to the reference scenario. In the same year however, the income of *condensing units* increases from insignificant 0.2 and 5.7 million Euros in the reference system, respectively, to 26 and 58 million Euros in the heat pump system (see Table 7.9), which is due to the higher shadow prices on electricity as well as the lower heat prices. Heat pumps hereby contribute to a re-introduction of condensing units.

In the heat pump scenario of 2017, the income of extraction units decreases (again) to an average of 27 million Euros, which is relatively low compared to the income on 34 million Euros in the same year of the reference system. As the wind capacity in the heat pump scenario increases further (to the 2025 wind scenario), the average income of extraction units decreases to just 21 million Euros, which is lower compared to the 28 million Euros in the reference scenario. The income of condensing units is still much higher in the heat pump scenario, although decreasing.

For central units, conclusions are that both extraction and condensing units benefit from installing heat pumps (according to the modeled capacities) compared to the reference system, when wind production corresponds to the 2008 system. Main reason for this is that the installed amount of heat pumps increase the electricity demand (especially in the decentralized areas), thus rising the electricity price and consequently increasing the income. However, when the wind capacity reaches the level of 2017, the income level of extraction units drops considerably when compared to the reference system. A tendency which continues while expanding the wind capacity further to the 2025 wind scenario. Anyhow, fans of condensing electricity will cheer at the heat pumps, while these increase the incentive for a more efficient power generation alone.

In Table 7.10 below is shown how the income of the remaining production units in both the reference and heat-pump scenario is affected by the different wind capacities. Since just a small part of the total production is produced on central backpressure units and peak load units, the remaining production consists of decentralized backpressure units, wind production, plus central and decentralized boilers.

In the reference scenario is seen that the income of boilers, both in the central and de decentralized areas, will increase as the wind capacity is expanded. A particularly large (relatively) increase in revenue occurs for the central boilers, as the income goes from just 4.5 million Euros in 2008, to 27 and 65 million Euros in 2017 and 2025, respectively. Decentralized CHP units simultaneously loose a small share of the total production, due to the lacking boiler capacity in this heat area. In the heat-pump scenario the incomes of decentralized CHP units and boilers are reduced to a minimum by 2025, when compared to the reference scenario. Wind power units will benefit the most from the heat pump scenario with an income rise by around 70 % in 2017 and 100 % in 2015 – compared to the reference scenario. This means that heat pumps in general improves the revenue base for units specialized in generating power while the opposite being the case for units with a more heat-producing function (boilers and backpressure units).

Ann. Income (Mill. € per year) **scenarios:**		**Decentralized CHP**	**Boilers, central**	**Boilers, decentralized**	**Wind**
	2008	294,04	4,47	126,85	92,16
Reference	**2017**	277,43	27,15	144,31	129,80
	2025	272,29	64,15	154,03	122,55
	2008	12,20	0,30	1,93	138,31
Heat pump	**2017**	8,35	1,21	4,42	222,81
	2025	5,87	4,00	6,02	254,01

Table 7.10, Comparison of annual income of the remaining production in the reference and heat pump scenario through the wind capacities of 2008, 2017 and 2025. Note here that the income of wind production in the reference scenario is higher in 2017 than in 2025.

7.2.5. Single power plant economy – general tendencies

When looking at the economy of the single power plants, it can generally be said that the economic situation of the central units is worsened as the wind capacity increases towards the 2025 wind capacity scenario in the reference scenario, while the income of decentralized CHP units is relatively unharmed by the drastic change in wind capacity. The reasons for the reduced revenue base of central units are mainly found in a lower annual CHP load factor, and fewer operating hours, caused by an increased demand for boiling capacity as a result of falling el. prices, while insufficient decentralized boiling capacity insures decentralized CHP production a constant, high LF and thereby income.

It seems as if operating with optional bypass might have a reducing effect on this development. Not only is BPO chosen as optimal operating mode most of the time in cold periods of 2017 and 2025 (and often in 2008 too), BPO also increases the commitment factor, ultimately reducing the number of necessary start-ups. Also, applying BPO full-scale was seen having an equalizing impact on the load factors of extraction units, when compared to the favoritism of the three reserve-capacity units seen in the reference scenario. Finally, it was discussed how the economic potential of bypass most likely could be much higher in the real system, due to the problem of the lower production limit of the boiler often exceeding the heat demand, easily can be coped with through heat storage in the real system. A further symptom of the greater potential was seen in that; the model more frequently chooses to oversupply heat rather than operating in the lowest backpressure point of operation, when approaching 2017 and 2025.

Heat pumps generally have a negative impact on the individual economy of CHP plants. This is especially the case for units specialising in heat production such as boiler- and backpressure units, while extraction units are affected less negatively, due to their low production costs and ability to increase the power generation relative to the heat production (towards condensing). Opposite to this, the economic base of condensing units is transformed from being non-existing to being on equal footing with extraction units. Moreover, the annual commitment factors of extraction units averagely drops, along with a number of start-ups being three times as high as in the reference scenario, which is argued not to be an optimal condition for central units.

7.3. Constraint analysis

In chapter 5, it was explained that the main objective of the model is to minimize the total costs of a system consisting of a number of production units, while satisfying a number of constraints (first of all including the satisfaction of an electricity and heat demand). In addition it was mentioned that the change in optimized total costs, connected to the relaxation of a constraint by one unit, can be interpret as the shadow prices of the particular constraint. Until now, shadow prices have only been analyzed in connection with the constraints satisfying the heat and electricity demand, which in this project is directly interpreted as the electricity and heat price, respectively. In this section, shadow prices will be used to determine how some of the restrictions in the model constrain the optimal balancing of the heat and electricity demand. As the physical properties of central units is one of the main focuses of the current project, the first part of this analyse will concentrate on the different physical limitations characterizing the central power units. Secondly, the electricity-heat relation of backpressure units, capacity limits on interconnections and the maximum production of decentralized boilers will be analysed, and finally, the value of increasing the wind capacity will be examined.

7.3.1. Central power unit-constraints

As described in chapter 5, the central extraction units have been modeled with upper and lower bounds given by two isofuel lines, plus a backpressure line restricting the maximum output of heat relative to the electricity output. In the following three figures, representing the electricity-heat production diagram of the extraction units (Figure 7.3), the hourly CHP production points of central units will be scattered as x,y coordinates respectively (seen as black points of the graph), in order to observe these in relation to the physical constraints given by the backpressure line, as well as the min and max power generation limit. Furthermore, the production of the central units has been standardized in order for the plot to contain all central units of the model. Here, the red points indicate the power generation of the condensing units.

At first, the electricity-heat diagrams of the reference scenario is analyzed, then the diagram of the bypass scenario and finally the diagram of the heat pump scenario. In Figure 7.3 below, the production points of the reference system in the months: January, May and September, subjected to the wind profiles of 2008, 2017 and 2025 is shown[34].

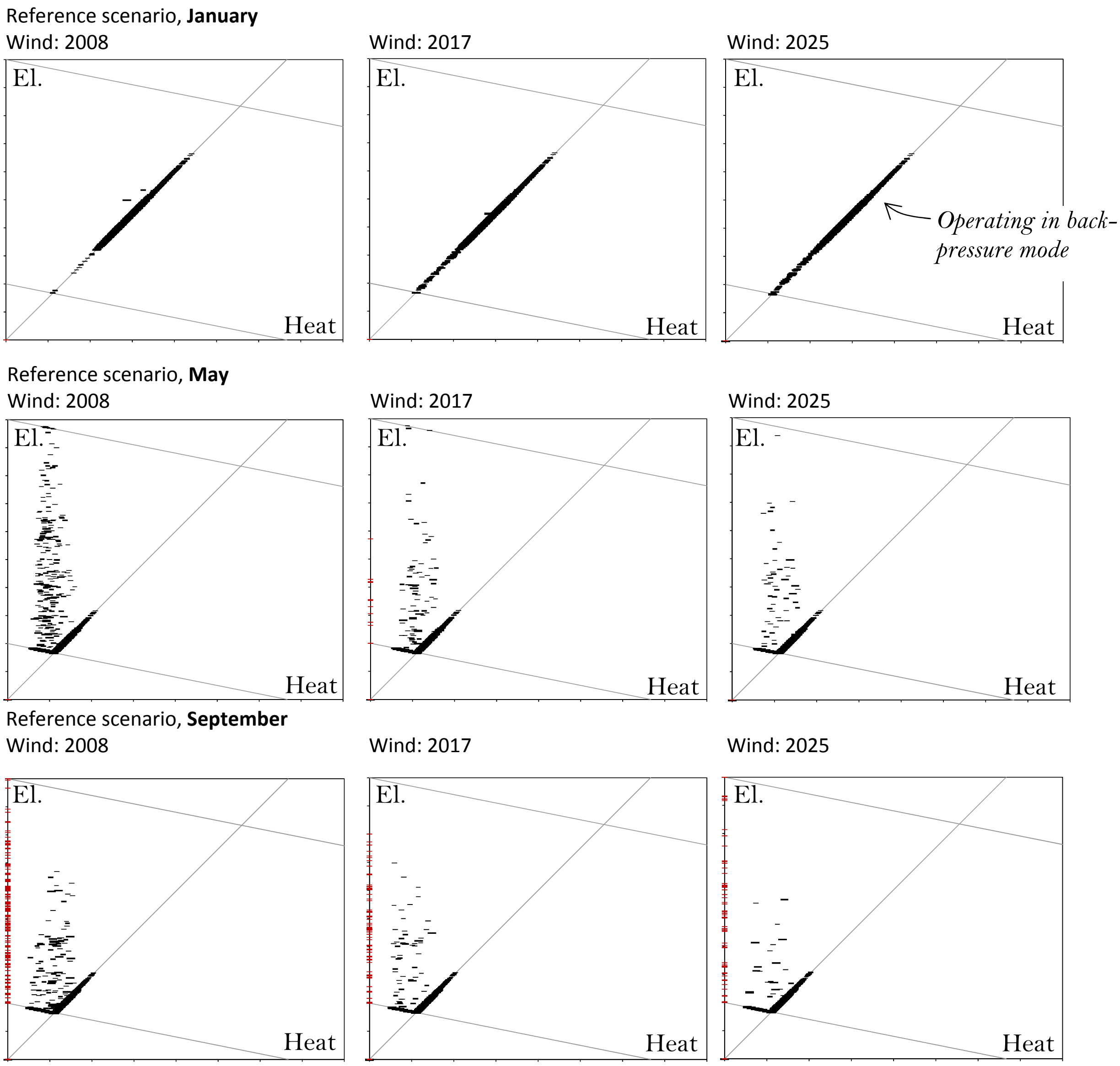


Figure 7.3, Comparison of central production history in relation the upper and lower constraints (heat-electricity diagram), optimized for January, May and October subjected to the wind capacities of 2008, 2017 and 2025.

When comparing the electricity-heat production of the different months subjected to the varying wind penetration, it is seen how the co-production in January is characterized by backpressure-operation the entire time, at all three levels of wind penetration, indi-

[34] The three months have been chosen as good examples on the annual variation in production, January being the coldest, May the late spring, and September representing the fall.

cating that heat is more needed than electricity. As a consequence, there is no demand for production from condensing units.

Looking at the production in May in 2008, there seems to be a relatively large amount of production hours lying in-between the constraints. Still however, a great amount of the production seems constrained by partly the lower part of the backpressure line as well as by the minimum power generation, indicating a small heat demand. As the wind capacity increases towards the 2025 wind scenario the trend of CHP production being constrained by the backpressure and minimum electricity generation limits, increases.

Regarding the production in September 2008, the pattern looks similar to the one in May, except that in September we see a great amount of production from condensing units, which indicates periods with higher electricity- than heat demand. In this connection, it is worth mentioning that the condensing units are modeled with a slightly higher electrical net efficiency (50 %) than extraction units, when extraction units operate in condensing mode (45 %). This explains why the extraction units never generate condensing electricity. When the wind capacity increases, the amount of condensing electricity is gradually reduced, and the production from extraction units is more “pressed” down towards the backpressure- and electrical minimum constraints. This indicates an increased need for producing more heat while maintaining (or reducing) power generation as well as to generate lesser power than allowed by the technical minimum of the boiler, respectively (if the opposite was the case, with more power being needed, this could easily be generated by ‘moving’ the production point away from the backpressure line).

The production diagram of the bypass system (full-scale) is seen in Figure 7.4 below, comparing the production in January, April and November, all subjected to the windy profile. As is the reference system, we see that January is characterized by all extraction units operating in bypass mode constantly (with the exception of a few hours), whereas the production in April and November to a greater extent is co-generated. It is the presumption that a share of these hours of backpressure operation rather would be in BPO mode if the lower capacity-limit had been lowered.

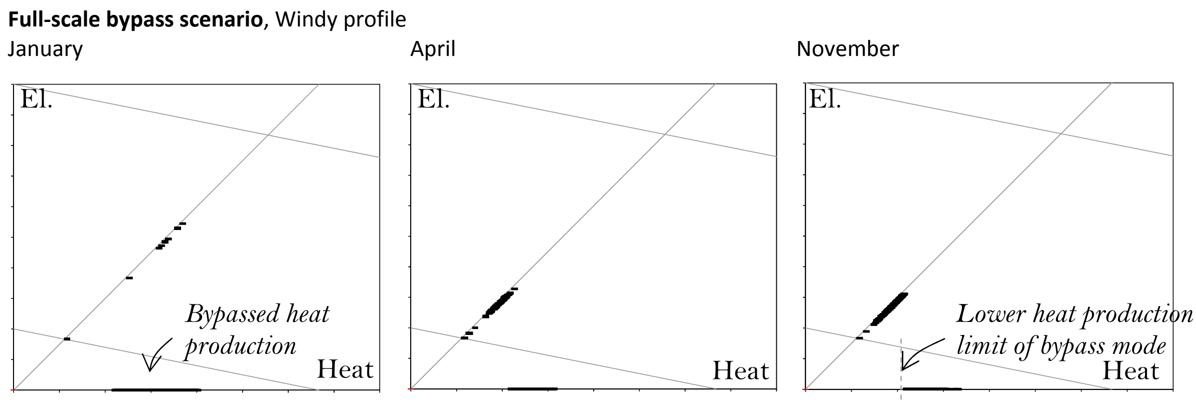


Figure 7.4, Comparison of the central production history in relation the upper and lower constraints (heat-electricity diagram), optimized for the full-scale bypass scenario for January, May and October, all subjected to the windy profile.

With this being said, it is important to stress the fact that extraction units operating in backpressure mode not automatically means that electricity generation is completely constrained by the heat. This is illustrated by Figure 7.5 below, showing a plot of the production in April and November both subjected to the wind penetration anno 2017, in which heat is alternately produced during backpressure- and bypass mode, respectively.

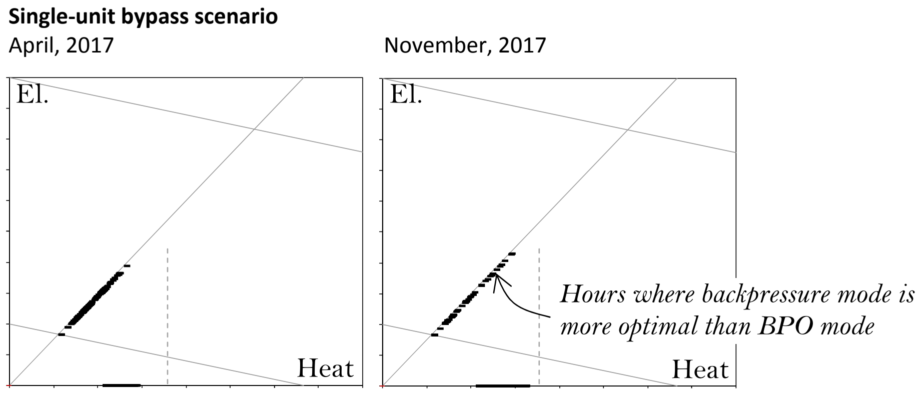


Figure 7.5, Two months in 2017 – April and November - showing the production of a single unit with BPO applied. The plots illustrate an example of heat produced in back-pressure mode, deselecting the bypass mode.

The implementation of central heat pumps ultimately results in a more scattered plot as seen in Figure 7.6 below, which is a consequence of the increasing demand on electricity. In addition to greater diversification, an increased amount of condensing electricity in January, alongside with a great amount of co-generated heat produced in backpressure mode, is seen. An interesting tendency in the January heat pump scenario, is that the optimal solution requires the two types of power plant producing energy separately the way they do it the best: by condensing- and backpressure mode, respectively (and not particularly in between these operating modes). The production in May is very scattered too, but characterized by a lower heat production than in January. A general thing, characterizing the production under the inclusion of heat pumps, is the upper power limit being reached more frequently.

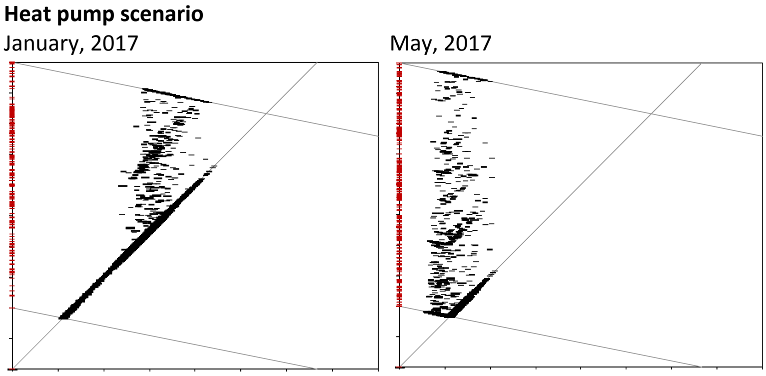


Figure 7.6, Two months of the heat pump scenario, subjected to the wind of 2017. Here, cogeneration is taking place above the backpressure line more frequent than compared to the other scenarios.

All in all it can be said on the basis of the electricity-heat diagrams above, that particularly the lower restrictions of the modeled central power units – being the minimum power output and the backpressure line – are constraining the optimal production most of the time, when approaching the 2017 and 2025 scenarios. It is furthermore seen that extraction units, when having applied optional BPO, are able to disregard these lower (technical) restrictions by switching to pure heat production, and that this tendency is strongest in January, where the heat demands are generally larger than the minimum heat production during BPO, which is opposite to May and September where switching to BPO would mostly result in the before-mentioned oversupply of heat. Moreover, the heat pumps seems to have the effect of 'freeing' the operational points from the lower power- and backpressure limit plus creating an increased the base for condensing electricity. The main reason for this is an increased demand for coal-based power generation created by the heat pumps. In relation to this, a tendency has been observed towards letting extraction and condensing units do what they individually do best – which is running in backpressure and condensing mode, respectively.

However, the presented diagrams provide just a visual indication of the different operational situations. In the following section the different factors observed will be further elaborated through analysis of the shadow prices.

Shadow prices from constraints

In the following, the modeled shadow prices will be review and analyzed in relation to a selected number of constraints that are expected to result in significant limitations on the optimal solution. More specifically, the shadow prices will be used to gain information about the following two things: 1) the share of hours that the observed (linear) equation constrains the optimal solution and 2) the average shadow price within these hours. As the first value will indicate how often the limits are constraining the solution, the second value is a measure of the extract costs of marginally relaxing the observed constraint. In relation to CHP units, the shadow price *value* can be further interpreted as the difference between the actual electricity price, and the electricity price needed in order to balance the power generation costs. To explain this, an example is seen in Table 7.11 below which shows a sample of two operating hours of an extraction unit with different production and price levels. The shadow price of the backpressure line is different from zero which tells us that the unit is cogenerating heat and electricity in backpressure mode. In the first hour the shadow price of electricity is 17.20 €/MWh, the heat price 18.20 €/MWh and additionally the shadow price of the backpressure line is 17.98 €/MWh. Now, since the marginal generation costs of electricity (see section 5.4) is 35.18 (when there is no income from heat), the difference between the electricity price and the marginal costs is reflected in the shadow price, thereby indicating the amount of electricity that needs to come from heat (or elsewhere). In the second hour, the electricity price drops to a critically low 1.06 €/MWh resulting in a higher shadow price on the backpressure constraint of 34.12, in order to level out the marginal generation costs. In addition to this, the heat price of the particular hour increases. Since the extraction unit seen here is the marginal utility of the total heat supply, the heat price level balances the income, resulting in a profit of zero.

Shadow prices from an extraction unit:

Hour of operation	Energy converted [MWh]			Shadow prices of: (€/MWh)					El. supply + Backpressure	Marginal el. gen. costs
	Fuel	El.	Heat	Heat supply	El. supply		Backpressure limit			
t442	496	194	259	18.76	17.20	+	17.98	=	35.18	35.18
t443	482	189	252	30.86	1.06	+	34.12	=	35.18	35.18

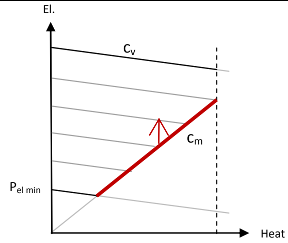
Table 7.11, A numeric example of shadow prices from extraction units.

It is important to stress that the shadow price of the backpressure line in the example above, constraining the relation between heat and electricity, not reflects an immediate economic loss from the constraint, but rather the contribution from additional heat production. In this relation, the shadow price can be used to determine whether the purpose of a production-hour of a particular unit is to produce heat in order to generate electricity, or the other way around.

Table 7.12 below shows the amount of shadow prices different from zero resulting from a one-unit relaxation of the backpressure line. The shadow prices that equal zero are not constrained by the backpressure limit. The table figures are calculated relative to the factor of annual commitment. In the reference scenario 2008, averagely 67 % of the year a shadow price is generated from the backpressure constraint, a number which increases to 69 % in both 2017 and 2025. This means, that the drastic expansion of the wind capacity towards 2025 does not significantly change the amount electricity constrained by the heat demand.

Moving on to the heat pump scenario of 2008, by an average of 47 %, the average amount of hours with shadow prices from the backpressure line is lower than in the corresponding 66.2 % seen in the reference scenario. However, as the wind penetration increases so does the constrained electricity resulting in a factor of 57 % and 63 % in 2017 and 2025, respectively. This means that heat pumps do not reduce the *amount* power in the future system, as significantly as expected, approaching 2017 and 2025.

*Shadow price factor, **backpressure*** [%]

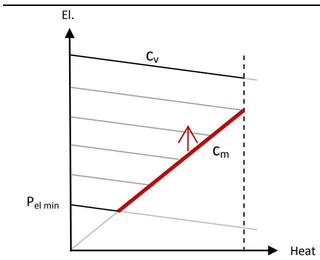


SYSTEM SCENARIOS:	Central units:	G1	G2	G3	G4	G5	G6	G7	Mean
		Extraction units							
Reference	**2008**	66.2	65.7	65.6	67.5	68.5	66.7	66.1	**66.6**
	2017	70.0	66.6	66.6	70.3	69.7	69.4	69.6	**68.9**
	2025	68.6	66.9	66.9	69.6	70.0	69.2	68.0	**68.5**
Heat pump	**2008**	46.2	46.2	46.8	45.7	47.4	45.7	47.5	**46.5**
	2017	57.6	57.9	55.0	55.7	56.6	56.6	58.9	**56.9**
	2025	63.6	61.2	62.2	62.0	61.0	62.4	66.0	**62.6**

Table 7.12, Shadow price factors – the amount of operating hours with shadow prices different from zero, indicating the share of electricity generation constrained by the heat demand. As seen on the red line, shadow prices are generated by relaxing the linear constraint one unit in the electricity's direction (y-axis).

One thing is how *frequent* the backpressure limit causes (or forces) the electricity to be constrained, another, is the size of the particular shadow prices and thus, the necessary contribution from heat. Table 7.13 below shows a comparison of the average shadow prices of the extraction units in the different system scenarios, showing significant differences between the reference and heat pump scenarios as well as difference between the different wind penetration levels. In the reference scenario, the average shadow price increases from 17 €/MWh in 2008 up to 20 €/MWh and 22 €/MWh in 2017 and 2025, respectively, being a logical result of the low electricity prices caused by the increased wind penetration (cf. the increasing heat production costs from falling electricity prices). In the heat pump system, the average shadow price is around one third of the corresponding shadow price of the reference scenario. The main reason for this is probably the higher shadow price on electricity characterizing the heat pump system.

*Average shadow price, **backpressure*** [€/MWh]

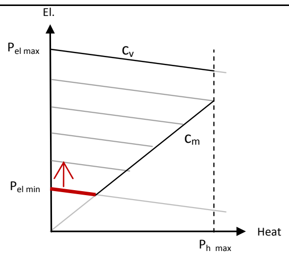


SYSTEM SCENARIOS:	Central units:	G1	G2	G3	G4	G5	G6	G7	mean
		Extraction units							
Reference	**2008**	17.28	17.02	17.01	17.08	16.89	17.18	17.28	**17.11**
	2017	20.42	20.47	20.47	19.99	20.31	19.97	20.44	**20.30**
	2025	20.79	23.79	23.79	20.90	23.62	20.83	20.54	**22.04**
Heat pump	**2008**	5.74	5.74	5.74	5.75	5.71	5.75	5.71	**5.73**
	2017	6.90	6.67	6.76	7.05	6.64	6.98	6.93	**6.85**
	2025	7.61	7.35	7.58	8.25	7.35	8.14	7.91	**7.74**

Table 7.13, Average shadow price level from backpressure constraint. Note that the average shadow price level of the heat pump scenario is about one third of the corresponding price in the reference scenario.

So far, we have seen, that when the electricity price drops to a critically low level, the central power generation decreases to a minimum (if not de-committing) while maintaining a correspondingly low heat production. Therefore, the constraint given by the lower bound of the power generation $P_{el,min}$ is assumed to affect the optimal solution. In Table 7.14 the shadow price characteristics of this particular constraint is seen, calculated for the reference system subjected to the different wind capacities. Compared to the back-pressure constraint shown above, the minimum power limit is only constraining the solution around 23 % of the time during 2008. However, when subjected to the 2017- and later on the 2025 wind capacity, the share of constrained hours increases significantly, first to 33 % and then 40 % of the annual production. Thus, the amount of production hours constrained by the minimum power generation limit is sensitive to the increasing large wind penetration. The average level on shadow prices from the minimum power generation is more or less constant around 12 €/MWh, approaching the wind penetrations of 2017 and 2025.

*Shadow prices, **minimum el. power limit***



		Extraction units							
Reference scenario: Central units:		**G1**	**G2**	**G3**	**G4**	**G5**	**G6**	**G7**	**mean**
Shadow price factor [%]	**2008**	21.8	24.4	24.4	21.9	22.4	22.0	22.0	**22.7**
	2017	29.8	36.2	36.2	30.9	33.3	31.5	32.2	**32.9**
	2025	33.9	49.2	49.2	34.0	46.7	33.8	34.0	**40.1**
Average shadow price [€/MWh]	**2008**	11.10	12.35	12.35	11.40	12.11	11.28	11.28	**11.70**
	2017	12.28	13.05	13.05	12.32	12.65	12.53	12.22	**12.59**
	2025	12.99	11.56	11.56	12.60	10.84	12.78	13.04	**12.20**

Table 7.14, Relative share plus average level of shadow prices from the electrical minimum constraint, modeled for the reference scenario.

As mentioned earlier, the exact factors determining the minimum power capacity have traditionally not being given much attention by central power plant operators. However, since the amount of constrained production increases with the increase in wind capacity, by which the production at minimum capacity increases, avoiding this situation will be preferable and thereby requiring more attention of this particular area of operation in the future.

Constraints of external transmission and other production units

After having seen the impacts of the varying wind penetration on the constraints of the central units (in relation to the system scenarios) a study of the effect on the additional production unit is of interest. Therefore, in this section, the shadow price-characteristics of the following constraints will be reviewed:

1) Backpressure line of backpressure units (electricity/heat relation)
2) Upper capacity limit for decentralized boilers,
3) Upper and lower capacity limits on external connections, and finally
4) The upper capacity of wind power

The reason that these particular four constraints are highlighted is that each of them represents a fundamental characteristic of the modeled system. Because of the power-heat relationship in decentralized backpressure units (1) being fixed, the shadow prices of this restriction will indicate the imbalance between their marginal production costs.

Furthermore, the shadow price will be used as an indicator of the impacts of the varying wind capacities on this imbalance. As it was the case for extraction units, the shadow price of backpressure units equals the marginal change in total costs when relaxing the backpressure line one unit in the electricity's direction (when visualizing the x-y diagram for heat and electricity). Consequently, it takes an additional MWh of electricity to produce the same amount of heat (as for extraction units), and the extra costs from this are expressed by the shadow price. Therefore, when the shadow prices from the backpressure constraint are positive (expressing an economic loss) it would be more optimal to produce heat without simultaneously producing electricity. When the shadow prices, on the other hand, are negative (expressing an economic gain), it would be more optimal to solely generate electricity.

As the wind capacity increases, decentralized boiling capacity to a greater extent than backpressure units is estimated the optimal producing unit of heat (as shown in section 6.3.2). The main reason for this is that the production costs of decentralized boilers are free from contributing to the generation of cheap electricity. In the light of this, it is relevant to examine how the value of boiling capacity is affected by the different system scenarios and wind capacities, hence 2).

The shadow prices of the external capacities in (3) will first of all indicate how often the exchange limits both ways are reached, and secondly, the economic loss of the price differences resulting from the constraints.

As for the upper boiling capacity in (2), the shadow price generated from the upper wind production limit (4) indicates the value of a marginal raise in the production limit. For example, when the wind production is low, the (negative) shadow price of the possible maximum production will indicate the marginal gain of having one unit of wind power replacing an additional unit from one of the competing producers. When the wind penetration level on the other hand is high, one can reversely experience a zero shadow price which indicates the case of electrical spillover – the wind being practically worthless.

At first, Table 7.15 below presents the annual shadow-price factors of the units listed above, and further below, Table 7.16 shows the average shadow-price values of the particular constrained production hours. Both tables compare the results of the reference- and heat pumps scenario subjected to different wind capacities, while the changes in production of the single-unit bypass scenario does not have a significant impact on other units than itself.

Ad 1) Back pressure units:

Observing the shadow price characteristics of decentralized backpressure units, we see that in the reference scenario of 2008, the shadow price is positive 78 % of the time – meaning that the electricity generation is constraint by the heat demand. Conversely, 10 % of the time the same year, heat is produced in order to generate electricity – mainly the case during electrical peak demands in mid-day. However, as the wind capacity increases towards the 2017 and 2025 scenarios, the amount of hours with heat-constrained electricity increases too, so that the distribution of positive/negative shadow prices become 89/5 % in 2017 and 92/3 % in 2025, respectively. A similar development is seen when looking at the average shadow prices in the reference scenario. In the hours where the electricity generation is constrained by the heat demand, the average price goes from approximately 13 €/MWh in 2008 to 15 €/MWh and 17 €/MWh in 2017 and 2025, respectively. In the relatively few hours where heat is constrained by the electricity supply, the shadow prices on the other hand are relative small, around -3 €/MWh at all wind penetration levels. This trend is a natural consequence of the falling electricity prices from the modeled wind expansions.

Shifting focus to the heat pump scenario, the situation is generally turned around. In 2008, heat is suddenly produced as a byproduct of electricity approximately 95 % of the hours – a share which decreases to around 88 % and 78 % in 2017 and 2025, respectively. Consequently, the share of constraint electricity only occurs about 4 % of the time in 2008, increasing to 11 % and 21 % of the time in 2017 and 2025, though.

Annual shadow prices factor [%], ***heat pumps***		**Backpressure units, decentralized**		**Boiler, decentralized**	**External connections**		**Wind**
SYSTEM SCENARIOS:		Shadow price > 0	Shadow price < 0		Export	Import	
	2008	77.8	10.3	59.2	1.7	23.3	100.0
Reference	**2017**	88.9	4.7	66.9	13.2	12.0	93.5
	2025	92.4	3.1	69.6	28.7	8.3	78.7
	2008	4.5	94.6	0.0	0.0	81.7	100.0
Heat pump	**2017**	10.6	88.5	0.0	0.7	58.5	99.3
	2025	21.2	78.0	0.0	8.1	42.9	92.2

Table 7.15, Comparison of the annual factor of shadow prices in the Reference and heat pump scenario, as seen from the other production (while single-unit BPO scenario being left out, having low impact on the total system).

Average shadow prices [€/MWh], ***heat pumps***		**Backpressure units**		**Boilers, decentralized**	**External connections**		**Wind**
SYSTEM SCENARIOS:		Shadow price > 0	Shadow price < 0		Export	Import	
	2008	12.73	-3.28	-7.74	-16.13	15.10	-20.45
Reference	**2017**	14.77	-3.45	-9.15	-16.66	15.01	-17.98
	2025	17.44	-3.34	-10.89	-16.92	14.90	-17.25
	2008	2.73	-9.95	0.00	0.00	15.30	-29.70
Heat pump	**2017**	5.18	-8.92	0.00	-17.20	14.84	-25.93
	2025	4.85	-8.47	0.00	-17.16	14.70	-23.99

Table 7.16, Comparison of the average level of shadow prices in the reference and heat pump scenarios, for the additional production units.

Additionally, the impacts of applying the opportunity of BPO to extraction unit in full-scale, are seen from the figures of Table 7.17 below, modeled on the basis of one-week-samples all subjected to the windy profile. Despite of the great inaccuracies of the optimized solutions described earlier, the BPO option seems to have a positive effect on the average shadow prices from the backpressure constraint going from 24 €/MWh in the reference scenario to 20 €/MWh, although no affect is seen in the 100 % share of hours with constraint electricity (keep in mind it is a windy profile).

*Shadow prices, **BPO, windy***		Backpressure units		Boiler, decentralized	External connections		Wind
SYSTEM SCENARIOS		Shadow price > 0	Shadow price < 0		Export	Import	
Reference	Shadow price factor [%]	99.9	0.0	82.0	69.3	0.0	46.4
	Average shadow price [€/MWh]	23.89	0.00	-14.07	-16.95	0.00	-11.67
BPO (full-scale)	Shadow price factor [%]	99.9	0.0	82.0	48.2	0.0	52.8
	Average shadow price [€/MWh]	20.38	0.00	-11.68	-17.17	0.00	-16.83

Table 7.17, Comparison of shadow prices in the reference and full-scale BPO scenario for the additional production units, calculated on basis of the selected weeks - all subjected the windy profile (3000 MW).

Ad 2) Decentralized boilers

The shadow price characteristics from the upper capacity limit of the decentralized boiler capacity are seen in the three tables above too. In the 2008-reference scenario, the optimal heat supply is constrained by the maximum capacity on the boiler 59 % of the year, meaning that within this period, a higher capacity would be preferable when seen from an optimization point of view. As the wind penetration is expanded, this share increases first to 67 % in 2017, and finally to 70 % in 2025. Correspondingly, the average shadow price goes from 8 €/MWh in 2008 to 9 €/MWh and 11 €/MWh in 2017 and 2025, respectively. While this may not seem as a significant increase between the different wind capacity levels, not a especially high shadow price level, one must remember that the decentralized heat demand constitutes around half of the total district heat consumption, by which the expansion of boiler capacity becomes a instrument for economic optimization more than half of the time. Additionally, when remembering that boilers use the same fuel as backpressure units (gas), the shadow price also reflects how frequently it would be optimal to skip the electricity generation while maintaining the heat production. Reversely, there is no need for capacity expansions in the heat pumps scenario with none negative shadow prices. The reason for this is that the included heat pump capacity outmatches the boilers to a degree so that the upper production limit of boilers never is reached for the entire year. Looking at the results from the modeled weeks of the full-scale BPO scenario, we see a small impact from the BPO options in that, the average shadow price of boiler capacities decreases by 17 % from 14 €/MWh to 11.7 €/MWh.

Ad 3) External transmission capacities

Regarding the external transmission capacities, it is seen in the tables above, that in the 2008-reference scenario, the optimized solution is constrained by the capacity limit on *import* 23 % of the year, and by the capacity limit on *export* around 2 % of the time, given the constant, low marginal costs of hydro power. However, this picture changes with the installation of wind capacities anno 2017 and 2025, as the share of production hours with constrained import decreases to 12 % in 2017 and further on to 8 % in 2025. The amount of shadow prices generated from the export limit, on the other hand, increases significantly to 13 % and 29 % in 2017 and 2025, respectively, thus being highly sensitive to the amount of wind power. The average shadow price level is relatively constant regardless of the increasing wind penetration.

When comparing the reference- to the heat pump scenario, once again we see a significant impact of heat pumps on the shadow price characteristics. The export limit constraining the solution is a rare case (not taking place in 2008 at all, and only in 1 % and 8 % of the time in 2017 and 2025 respectively), whereas the share of time where the *import* limit is constraining the solution is as high as 81 % in 2008, decreasing to 43 % in 2025, though.

From the results in the table comparing the full scale BPO- to the reference scenario (subjected to the windy profile); we see that the applied BPO option has a positive influence on the share of hours constrained by the export limit, going from 69 % in the reference scenario to 48 % in the BPO scenario. The average shadow price being around 17 €/MWh in both scenarios. This indicates, all things equal, an increased utilization of wind.

Ad 4) Wind power units

As seen in connection with the boiler capacity, the shadow price of the upper production limit of the wind capacity (the windy profile) expresses the economic gain of a marginal increase of this capacity, and will thus be interpreted as the instantaneous value of wind power.

Looking at the 2008-reference system in Table 7.15 above, the share of hours with a non-zero shadow price is 100 %, showing that the upper capacity limit constantly constrains the optimal solution. In practice, this means that no hours of *critical* electrical spillover (forcing down regulation of wind) have occurred within the reference scenario of 2008. Proceeding to 2017, this amount decreases to 93 % and further down to 79 % in 2025. This means that first 7 % and then 21 % of the year, respectively, the model down-regulates wind power due to critical spillover. Similarly, the average shadow price level of 20.45 €/MWh (gain) in 2008, decreases to 18 €/MWh and 17 €/MWh in 2017 and 2025, respectively. That is a 12-15 % averagely decline in the value of wind power when increasing the wind penetration level according to the 2017 and 2025 wind scenarios.

In the heat pump scenario (Table 7.15), the annual share of hours constrained by the upper capacity remains within a high level of 99.3 % in 2017, decreasing to 92.2 % of the time in 2025. Based in this alone, the modeled heat pump capacity seems to be a successful instrument for avoiding critical spillover. Furthermore, the average shadow price level is significantly higher in the heat pump scenario than in the reference system, with 30 €/MWh in 2008 declining to 26 €/MWh and 24 €/MWh in 2017 and 2025, respectively – all three being higher than in the 2008-reference scenario. An immediate interpretation of this is that heat pumps may be a perfect mechanism for maintaining a high incentive for continued investment in wind power.

Proceeding to the full-scale bypass scenario (Table 7.17), which have only been modeled for a selected number of weeks (subjected to the windy profile), it is seen how the applied BPO option again has a positive, yet modest effect on the utilization of wind. First, the total share of hours constrained by the upper wind capacity has increased from 46.4 % in the reference system to 52.8 % in the BPO system, which equals a decrease of 12 % in the amount of hours with critical electrical spillover. Moreover, the average shadow price of 11.7 €/MWh on wind capacity as seen in the reference scenario, increases to 16.3 €/MWh, which is an average increase of at least 44 % in the marginal gain from replacing one MW of wind power with one from the competing production (hence the value of wind power).

As mentioned earlier, one of the focus areas of this project is to assess the potentials of bypass and heat pumps for better utilization of the increasing wind capacity, by advancing a more flexible production. Finally, it has been shown that the problem with an increasing share of hours with export limitations (due to increased wind capacity) has been close to eliminated as heat bump capacity is applied. This, on the other hand, causes as great an increase in the demand that the share of *import* limitations additionally increase to approximately 60 % in 2017, thus maintaining the relevance of discussing external capacity expansions. In the full-scale BPO scenario this amount of time with import limitations decreases a bit, and simultaneously the average value of wind increases. Having argued that the periods with bypass switched on potentially could be extended in the real system (section 7.2.3), these positive effects could correspondingly be greater.

7.3.2. Constraint analysis – concluding remark

This means that, altogether, the shadow price of the four analyzed constraint show, that both the heat pump- and full-scale bypass systems generally have a relaxing impact on the CHP related constraints, as well as on the value of wind power. Heat pumps however, carry a potential of significantly increasing the need for expansions of external transmissions capacities due to the *import* capacity frequently constraining the solution.

7.4. Total system costs

In this section we will look at the total *variable* production costs of the different system scenarios – the reference system, the heat pump system and the full scale bypass system – under the influence of the increasing wind penetration towards 2025. The total costs is defined as the total production costs of all units within the main region (see Figure 7.7) plus the costs of import, minus the income from export. The costs of import from the exchange area (hydro) are calculated from the price level in the main region (not the exchange region) and the income from export is calculated from the price in the main region too. When the transmission limit is reached, a price difference usually occurs, which finally leads to the bottleneck income. As mentioned earlier (chapter x), the bottleneck income (roughly put) is an arrangement where the TSOs of the two systems exchanging power, gets to split the difference in the prices of the two systems multiplied with the transmitted power. The bottleneck income is included when calculating the total costs.

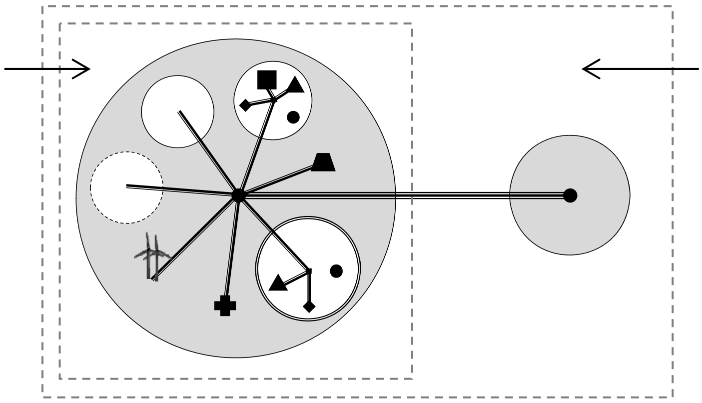


Figure 7.7, A repetition of the geographical model shown in chapter 5, in order to illustrate (by the dashed boxes) the system part being optimized and the system part being assessed in relation to the total system economy.

7.4.1. Total costs of the reference system

The calculated total costs of the reference and heat pump system is seen in Figure 7.8 below, and the corresponding numbers are seen in Table 7.18 further below. When looking at the reference system isolated, the total production costs seem relatively unaffected by the expansion of the wind capacity, decreasing by approximately 8 % between 2008 and 2017, and further 5 % between 2017 and 2025. The main contributor to this insensitivity is the constant production from decentralized boiler and backpressure units, which is caused by the lack of alternative heat production in the decentralized areas. The income from export only represents a small share (around 10-15 %) of the total economy of the system. However, it appears as if the import/export factors are the only ones reacting to the increased wind capacity, reducing the total costs of the reference system towards 2025, through 1) reduction of import, 2) an increasing income from export, and finally 3) increased bottleneck income from both import and export. Altogether, these do not form a large potential for economic optimization as the wind capacity increases.

7.4.2. Total costs of the heat pump system

In the heat pumps scenario, a decrease in the total costs on about 40 % from 2008 to 2025 is seen. The main contributor to this tendency (besides the increased wind capacity) is the complete down regulation of production from decentralized backpressure units. The total costs are a lot less in the heat pump scenario than in the reference scenario, and already in the 2008-heat pumps scenario, the total costs of 3,511 Million Euros represents only 61 % of the 5,767 million Euro total costs of the corresponding reference scenario – and, unlike in the reference scenario, the costs continues to fall as the wind capacity increases (indicating a much higher costs-sensitivity to the amount of wind capacity). Although the heat pumps scenario in some ways is quite extreme (given the large amount of pump capacity as well as the low fixed price of Hydro (import)), the system still emphasizes an economic system with a great potential for economic optimization – and even greater as the wind capacity increases – whereas the reference system appears quite rigid due to the heat-related costs (from CHP and boiler units) being unaffected approaching 2025. However, the unaffectedness of the heat-related production costs to the increased wind penetration is simply a consequence of the heat price always responding with increase of the marginal production costs, whenever the wind production is pushing the corresponding electricity price.

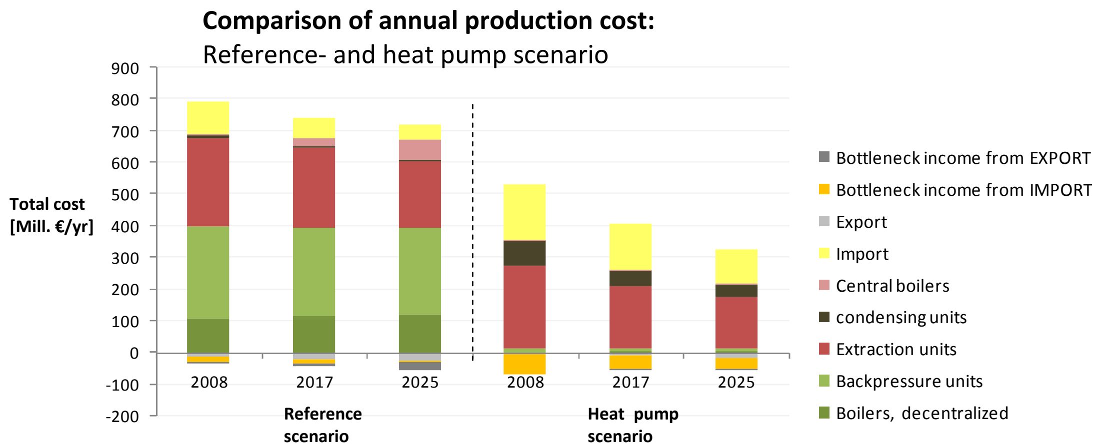


Figure 7.8, Total annual costs of the reference- and heat pump scenario subjected to the 2008, 2017 and 2025 wind penetration.

Annual system costs [Million €] **Heat pump scenario**		Central units			Decentralized units		Exchange		Bottleneck income from:		
SYSTEM SCENARIOS:		Extrac-tion	condens-ing	Boi-lers	Backpres-sure	Boi-lers	Ex-port	Im-port	ex-port	im-port	**To-tal**
Reference	**2008**	278	6	4	294	107	-10	104	-1	-18	**763**
	2017	253	2	27	277	118	-22	66	-12	-10	**700**
	2025	213	2	64	272	121	-24	48	-25	-6	**663**
Heat pump	**2008**	260	82	0	12	2	0	173	0	-66	**464**
	2017	198	51	1	8	4	-5	143	-1	-46	**355**
	2025	164	38	4	6	6	-15	110	-7	-33	**273**

Table 7.18, An overview of the values behind the figure above constituting the total costs in the heat pump and reference scenario.

The sources of the system income

A close-up of the sources of the system income in the heat pump and reference scenarios compared above is seen below in Figure 7.9. As mentioned, the income is based on export as well as bottleneck income from both export and import assigned to the regional TSO. Looking at the reference scenario, the system income in 2008 is characterized by one third coming from conventional export while the rest mostly comes from congestions on import from the exchange area. When looking at the 2017-reference scenario, half of the income is based on pure export while the other half is equally divided between the bottleneck income from export and import, respectively. Although the total bottleneck income is relatively unchanged compared to 2008, the 2017 scenario indicates a large increase in income from congestion on *export* by a factor of eight. In 2025 (reference scenario) the increase in export has stagnated and the income from bottlenecks on export is more than doubled.

The system income of the heat pump scenario in 2008 is entirely based on import-related bottleneck income and the income is more than twice as high as the total income of the corresponding reference scenario. The income level reflects a system with full utilization of wind power plus a generally high electricity price from the increased electricity demand. The same is the case for 2017 and 2025, though the income is decreasing. In 2017, the total income from export is below the level in the 2008-reference scenario, and we do not see a bottleneck income from export until 2025. The paradox of this is that heat pumps are introduced with the aim of increasing the internal consumption level in windy periods, thus reducing the need for extensions of external capacity. The model results however indicate that heat pumps will dominate local heat supplies even at high electricity prices. Consequently, the import could increase and along with this, the total level of bottleneck income from import. As a result, the need for extended external capacities will therefore, as a minimum, be maintained (even in 2025).

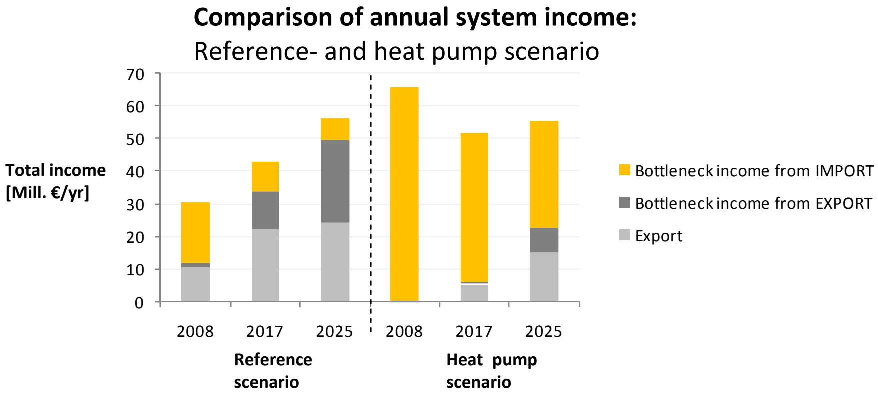


Figure 7.9, A close-up of the annual system income from foreign power exchange, comparing the reference- to the heat pump scenario.

7.4.3. Total costs of the bypass system

The total cost of the full-scale bypass scenario is calculated as well. The results are shown in Figure 7.10 and Table 7.19, representing the selected optimized weeks applied to the windy profile. As mentioned earlier, the average production of the windy week is 3000 MW, which only 5 % of the 2017 profile and 20 % of the 2025 profile is equal to or above. The modeled effects from applying BPO options to all seven extraction units will thus only be compared to very windy periods. The basic result from the BPO system is a decrease in the total costs of around 13 % in comparison to the reference scenario. Seen isolated for the central areas, however, the decrease is closer to 30 %. The main factor resulting in this decrease is the central boiler capacity being replaced by bypassed heat from extraction units. In the columns to the right, a close up of the total income is seen, which shows almost similar results for the two scenarios. However, by more detailed comparison there is a larger share of income from pure export in the BPO scenario, while the reference scenario has an overweight of income from bottlenecks. This is due to the increased amount of "cash" flowing directly between market players, rather than to the TSO companies, in the BPO scenario. Because we are looking at the windy profile only, there are no congestions on the import. Overall, the results of the BPO scenario are interesting in that, the economic optimization from BPO that is seen, solely is created from the central heat areas. In relation to this, there may be additional optimization potential form increasing the amount of heat production, disconnected from electricity generation in *decentralized* areas as well.

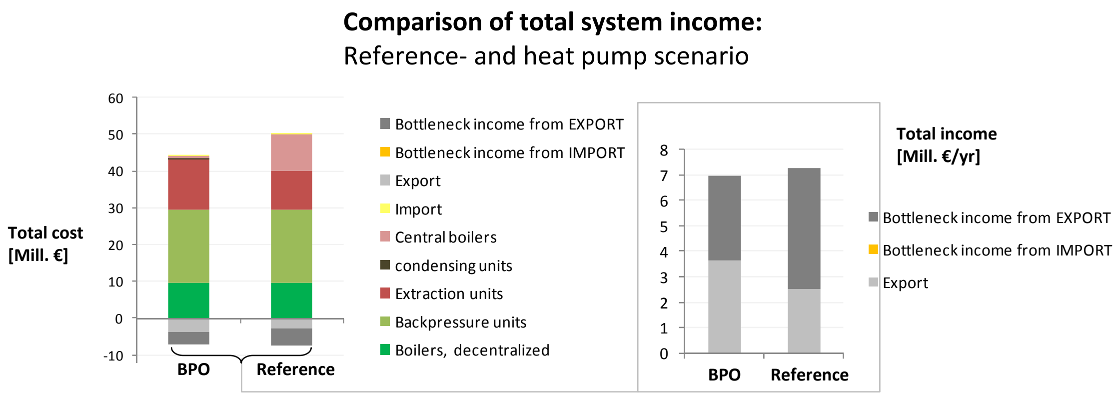


Figure 7.10, Left: total system costs of bypass and reference scenario (windy profile). Right: a close-up of the total income in the two systems.

Total system costs [Million €] **Bypass scenario**	**Central units**			**Decentralized units**		**Exchange**		**Bottleneck income from:**		
SYSTEM SCENARIOS:	Extrac-tion	condens-ing	Boi-lers	Backpres-sure	Boi-lers	Ex-port	Im-port	ex-port	im-port	**To-tal**
Bypass (full-scale)	14.0	0.0	0.6	19.9	9.8	**-3.6**	**0.2**	**-3.3**	**0.0**	**37.6**
Reference	10.3	0.0	10.3	19.9	9.8	**-2.5**	**0.1**	**-4.7**	**0.0**	**43.2**

Table 7.19, An overview of the values behind the figures above, constituting the total costs in the heat pump and reference scenario.

7.4.4. Total system costs – general tendencies

As seen from the results on the total cost of the different system scenarios, the total system costs decreases as the wind capacity increases – in both the reference and the heat pump scenario. However, the total costs of the reference scenario are highly insensitive towards the drastic changes in wind penetration, approaching 2025, as seen in the rather insignificant decrease in total cost. The main reason for this is the increasing wind capacity's lack of impact on the heat side of the CHP production, which simply covers the loss from the power generation by increasing the corresponding heat production costs. In this connection, the total costs of the heat pump scenario turn out to be much lesser than in the reference scenario, and with a continuing decrease towards 2025, for which the main reason is the heat pumps ability to combine the heat and power system.

The costs of the full scale bypass scenario are slightly lower than in the reference scenario (within in the observed windy periods), which is mainly due to the extraction units replacing the more expensive boiler capacity.

7.5. Green accounting

7.5.1. Applied methods for assessing the environmental impacts

Originally, the main motivation behind the political goal of the 50 % wind scenario is to reduce the CO2 emission by increasing the total share of renewable energy (RE). In this section, a number of environmental key figures from the different system scenarios will be reviewed – and among these, the total emission of CO2. When calculating the total amount of renewable energy, and thus the associated CO2 emissions, the following definition is used: The total share of renewable energy consumption is defined as the total share of the *final consumption* of heat and electricity coming from renewable sources. The calculation method is relatively new, originates from EU (Dansk Fjernvarme 2008), and has two advantages in relation to the Danish energy system. One is that, where the old method weighted the total share of renewable energy against the primary consumption, the new method gives wind power a relative larger share, by measuring it against the final consumption instead (Dansk Fjernvarme 2008). The second advantage is that the whole import/export issue can more easily be disregarded when measuring the *produced* power relative to heat and electricity consumption. Figure 7.11 illustrates the calculation method showing where the interrelated shares are measured (see black 'cuts') in relation to the final consumption of heat and electricity. Note here, that hydro power from the exchange area is included in the measure while importing, whereas export is excluded from the amount of final consumption. Import is regarded as renewable energy on equal footing with wind power as it only covers hydro power.

Whether heat pumps should be regarded as a renewable source is a little bit more complex. As seen earlier, the capacity within the modeled system has a COP value of 300 % which, all things equal, gives three units of heat for one unit of electricity. Logically, when looking at the heat supply as a source, we see that two thirds of the heat comes from earth heat – being a renewable source – while the remaining third comes from electricity. Two part of the produced heat from heat pumps is therefore regarded as renewable energy although some of the electricity from the third part comes from RE sources. Whether a greater part should be considered RE is discussed in appendix 11.2 where an analysis of the distribution of sources for the electricity used by the heat pumps is found as well.

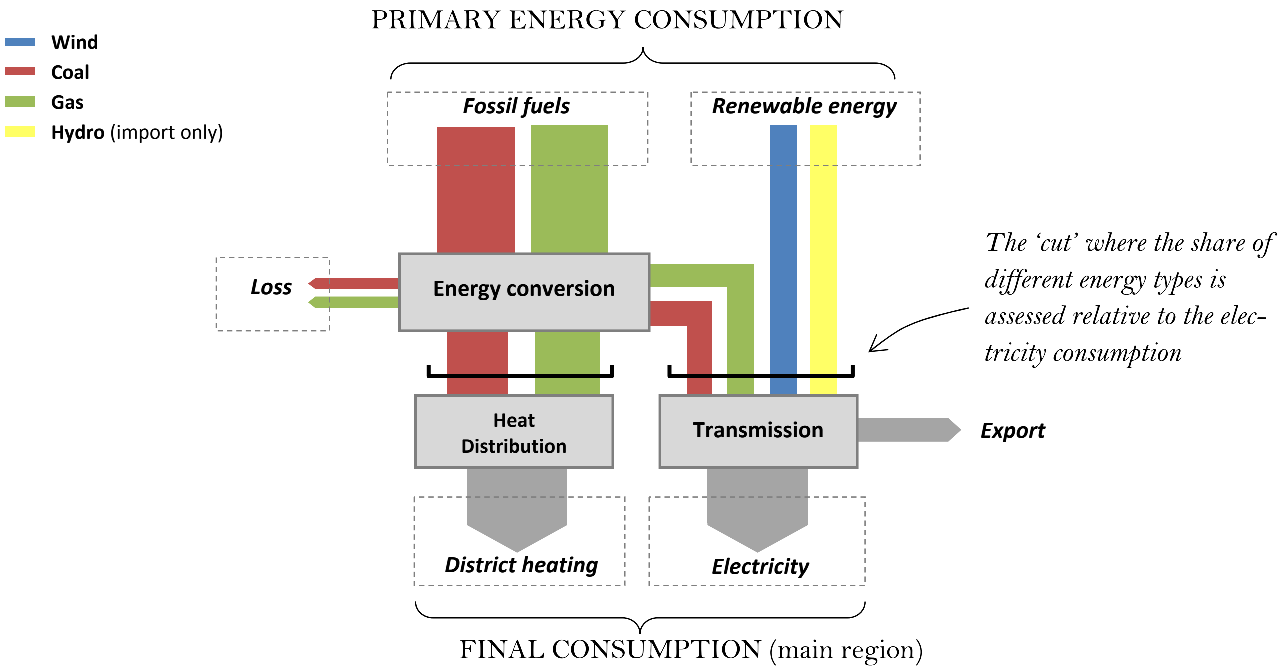


Figure 7.11, Illustration of the calculation method used in this project to assess the amount of renewable energy. Earlier, this relative share was measured against the primary energy consumption while it today is measured relative to the produced heat and electricity (own illustration).

7.5.2. Comparison of reference scenario and heat pumps scenario

Figure 7.12 and Figure 7.13 below show the relative shares of electricity and heat production to the total consumption, calculated from the method from Figure 7.11, comparing the reference- to the heat pump scenario. The values are rated such that the final total consumption gives 100 percent, by which it is seen that the total share of power generation (left) is larger in the heat pump scenario, due to the 17-21 % (2008-2025) increase in absolute electricity consumption that the heat pumps create. Regarding the electricity production of 2008, the share of wind power is approximately the same for the reference and heat pump scenario. But as a result of greater utility of the wind capacities in the 2017 and 2025 scenarios, the heat pumps scenario has a slightly higher share of wind at 23.2 % and 31.3 % in 2017 and 2025, respectively, compared to the 21.6 % and 27.6 % in the same years in the reference scenario – an improvement of wind utilization of 8 % and 13 %, respectively. When including the imported hydro power as part of the RE share, we see a much better result in the heat pump scenario with a share of 36 %, 43 % and 46 % of RE in 2008, 2017 and 2025, respectively, when compared to the corresponding 28 %, 32 % and 35 % of the reference scenario – a general improvement of more than 30 percent dedicated to heat pumps. If expecting an averagely lower import in West-DK, this improvement could be less. However, since the fixed low value of hydro power is applied to both scenarios, the observed *changes* between the scenarios become relevant in relation to the real system.

When looking at the sources of the heat supply (Figure 7.13 to the right), it is seen that the total share of the final heat consumption is smaller in the heat pump scenario (relative to the total heat and electricity consumption). In the reference system, the share of Natural gas-related heat production increases from 25 % to 30 % towards the wind capacity of 2025, which mainly is due to the increased boiler activity in the central areas. When comparing the two scenarios, it is shown that, what separates them the most is heat production from Natural Gas, which make up the greatest part of the heat production in the reference scenario but almost none in the heat pump scenario. In the heat pump scenario, on the other hand, the greatest source is earth heat, plus the electrical energy used for extracting it. Moreover, the heat supply based on coal (extraction and condensing units) have not been affected by the heat pumps (to the same extent as gas), being reduced by 15 % in the 2008, to 26 % and 27 % in 2017 and 2025. Note in this connection, that the coal-based heat production, when seen relative to the corresponding power generation, is smaller in the heat pump scenario too, indicating lower CHP-efficiencies than in the reference scenario. The growth in heat pump production is relatively small when compared to the relatively larger increase in wind production, due to a high production seen already in the 2008-heat pump scenario. This indicates that the competitiveness of heat pumps is not completely dependent on the formation of low electricity prices that the increased wind power causes. It therefore appears as though, already in 2008, extraction units (coal) are the only alternative production type apple to compete with the production costs of heat pumps.

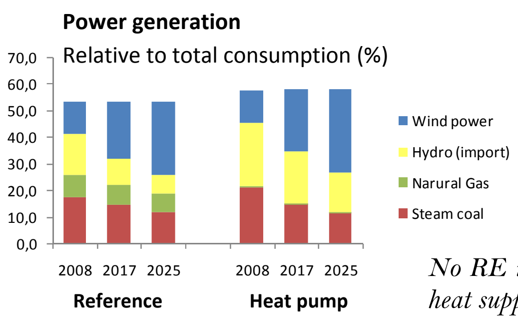


Figure 7.12, Comparison of the share of power generation relative to the total consumption.

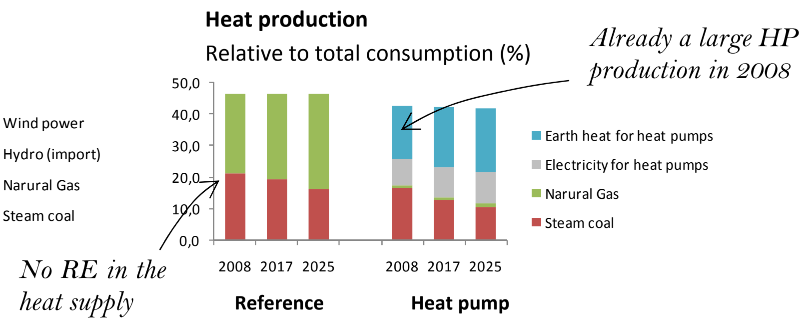


Figure 7.13, Relative share of heat production.

As mentioned above, the total share of renewable energy is measured on basis of the final consumption of heat and electricity. Figure 7.14 therefore shows the total heat and electricity supply, including hydro and earth heat as renewable energy sources, (with earth heat corresponding to two thirds of the heat pump production). When looking at the reference scenario, the total share of renewable energy only increases a bit as the wind capacity increases, going from 28 % in 2008, to 32 % and 35 % in 2017 and 2025, respectively. The reason for this is that, although the wind production is more than doubled by 2025, over the same period the import (hydro) is approximately reduced by half, curbing the growth in total RE. In the modeled heat pump scenario however, there is a very large share of renewable energy, coming from earth heat, increased import and improved utilization of wind power, respectively.

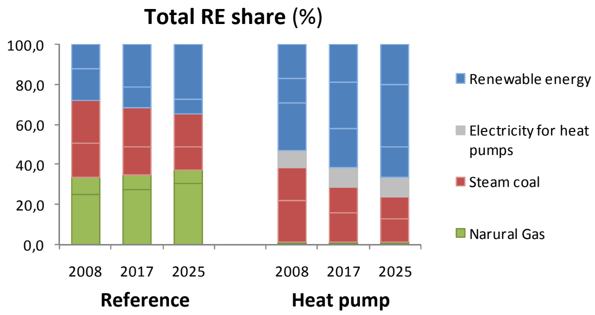


Figure 7.14, The total share of RE related to the share of coal, gas and consumed electricity by heat pumps. The RE represents wind, hydro (import) and earth heat (2/3 of produced heat from heat pumps.

7.5.3. Environmental impacts of bypass

Although the full-scale bypass scenario is modeled in a shorter time scale and subjected to the windy profile, the results of the relative production shares of heat and electricity is compared to the reference and the heat pump scenario (see Figure 7.15 and Figure 7.16 below). Looking at the composition of the power supply (left) we see that the reduced power from coal-based power plants in the BPO scenario allows a greater utilization of wind power and thus a greater RE share within the power supply (6 % increase when compared to the reference system). On the heat side however, there is a large increase in coal-related heat production (red) in the bypass scenario, when compared to the reference scenario, due to the extraction units replacing production from central boilers. The increased use of coal within the heat supply may result in a higher emission of CO2, given the higher MWh specific emission from coal than from Natural Gas. When calculated for the windy profile, this is in fact the case, as seen from the analysis below on “environmental key figures”.

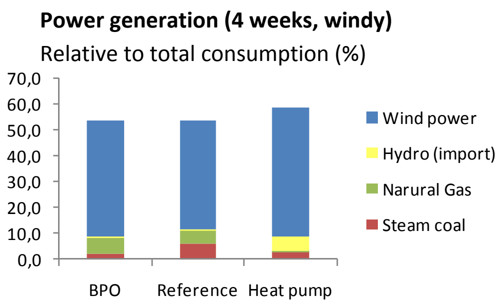


Figure 7.15, Comparison of relative share of power generation relative to the total consumption.

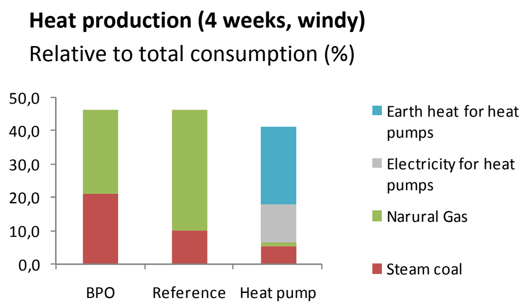


Figure 7.16, Relative share of heat production.

As for the reference- and the heat pump scenario, Figure 7.17 below shows the distribution of sources for the total heat and electricity supply. Again, earth heat, hydro and wind power are combined as renewable energy. As a result of applying full scale BPO options, there is a slight increased share of RE (6 %) compared to the reference scenario. Furthermore, the bypass scenario results in a higher amount of coal-related production, on a total basis. This however, only reflects the optimization of the four selected weeks subjected to the windy profile. If subjected to a less windy profile, the BPO scenario may be less distinguished from the reference system.

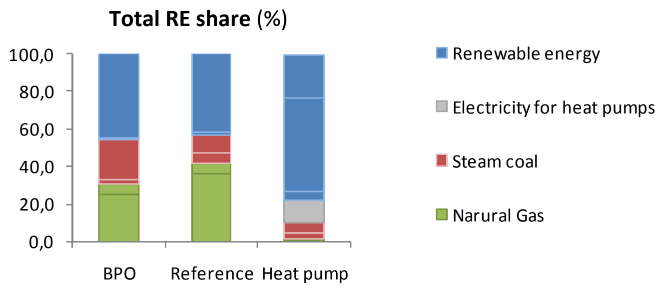


Figure 7.17, Comparison of the share of different energy sources relative to the final heat and electricity consumption, as seen in the bypass, reference and heat pump scenario.

7.5.4. Environmental key figures

Below is Table 7.20 and Table 7.21, showing a comparison of a number of environmental key figures – fuel, total CHP, CHP net efficiency, CHP emission and total emissions – calculated for the reference- , the heat pump- and the bypass scenario, respectively.

As seen in Table 7.20, the net efficiencies (CHP) for coal are approximately 88 % in the reference scenario which is quite high when remembering that the extraction units have been modeled with a maximum CHP efficiency of 92 % (when operating in backpressure mode). This indicates that extraction units operating at full heat production in general are more optimal than condensing units. One could even argue that extraction units are more optimal for heat production than for power generation. The CHP efficiency for backpressure units is set at a constant 90 % and is thus constant in all scenarios shown. In the heat pump scenario, the total net efficiencies for coal-based (central) production is just 76.5 % in 2008 – 11.5 percentage point lower than in the reference scenario – and around 79 % and 80 % in 2017 and 2025, indicating that central units as electricity producers alone can compete with heat pumps at being the most optimal supplier. As a result, production from coal emits 15 % more CO2 per MWh in the heat pump scenario. However, when comparing the CO2 emissions in the two systems, it is clear how the increasing wind production, has little impact on the total emission of CO2 in the reference system, going from 8,763 tons in 2008 to 8,282 and 7,701 tons CO2 in 2017 and 2025, respectively. In comparison, the emissions in the heat pump scenario are reduced to 63 % and 55 % of the reference values in 2017 and 2025, respectively. Heat pumps therefore have a greater potential when it comes to reducing CO2 emission – despite of lower efficiencies and increasing electricity consumption. The key factor behind the greater sensitivity to the increased wind penetration is the heat pumps ability to exploit the oversupply of power to achieve a leading rank in the merit order of heat supply. This way, “cheap wind power” can have an impact on the heat supply.

Environmental key figures

System scenario	Wind anno:	Fossil fuel-source	Fuel [GWh]	total CHP [GWh]	CHP net efficiency [%]	CO2 emissions [1000 tons]	Total emission [1000 ton]
Reference -	2008	Steam coal	17,190	15,101	**87.8**	5.8	**8.8**
		Natural gas	14,592	13,133	90.0	2.9	
	2017	Steam coal	15,420	13,639	**88.5**	5.2	**8.3**
		Natural gas	15,197	13,677	90.0	3.0	
	2025	Steam coal	12,963	11,462	**88.4**	4.4	**7.7**
		Natural gas	16,466	14,820	90.0	3.3	
Heat pump -	2008	Steam coal	20,704	15,845	**76.5**	7.0	**7.1**
		Natural gas	524	471	90.0	0.1	
	2017	Steam coal	15,101	11,887	**78.7**	5.1	**5.2**
		Natural gas	510	459	90.0	0.1	
	2025	Steam coal	12,226	9746	**79.7**	4.2	**4.3**
		Natural gas	576	518	90.0	0.1	

Table 7.20, Comparison of environmental key figures from the reference- and heat pump scenario, subjected to the increasing wind capacity towards 2025.

In Table 7.21, the bypass scenario is compared to the heat pump and the reference scenario. The environmental key figures are calculated for the modeled weeks (January, April, June and November) subjected to the windy profile. It is seen that, despite of the higher share of RE, the bypass scenario has a slight increase in the total CO2 emission as a result of the increased coal production.

Environmental key figures

System scenario:	Fossil fuel source	Fuel [GWh]	total CHP [GWh]	CHP net efficiency [%]	CO2 emissions [1000 tons]	Total emission [1000 ton]
Bypass -	Steam coal	851	746	87.7	0.29	**0.51**
	Natural gas	1,089	980	90.0	0.22	
Reference -	Steam coal	625	558	89.2	0.21	**0.50**
	Natural gas	1,443	1,298	90.0	0.29	
Heat pump -	Steam coal	372	321	86.2	0.13	**0.14**
	Natural gas	47	42	90.0	0.01	

Table 7.21, Comparison of environmental key figures from the four windy weeks (January, April, June and November) of the bypass-, reference- and heat pump scenario.

7.5.5. Green accounting – concluding remarks

Having analyzed the environmental effects of the modeled scenarios, it becomes clear that if no means are taken the increase in wind capacity alone (cf. the political goal) will only result in a slight increase in the share of renewable energy when it comes power generation, but none, when it comes to heat production. A positive tendency of the reference scenario is that the CO2 emission from gas-related boiler production will increase, as the wind capacity increases, replacing a much greater emission from coal-based CHP production. In both the heat pump and the bypass scenario, the share of renewable energy is greater than in the reference scenario – especially in the heat pump scenario – both in 2008, 2017 and 2025, and as a consequence of applying heat pumps, the CO2 emission from steam coal decreases much more, while emissions from gas-related production remains constant. However, the CO2 emission in the (windy) full-scale bypass scenario is slightly greater than in the reference scenario, as a result of coal-based extraction units replacing the gas-fueled boiler capacity.

Chapter 8.
Discussion

8.1. Reaching the objectives

The main objective of the present thesis is an examination of the economic and environmental impacts of wind power on a CHP based energy system like the West Danish energy system – today and with increased wind power capacity corresponding to the 2025 target – as well as an examination of possible instruments to avoid some of these consequences.

The objectives have been reached through various analysis, and in the following sections, the analysis, the methods and the results are discussed.

The crucial knowledge on the Danish energy system and the impact of wind power on the causing of critically low prices, have been achieved through a review of the Danish energy system and an analysis of the impact of wind power on the West Danish energy system today. As mentioned in section 3.2.1, the East- and West Danish power systems are separated transmission systems, and since the model represents one market area, the two are not compatible in one model. The reason why the focus primarily is on the West Danish power system (and not the East Danish) is that the power generation from wind turbines and hence the problems with the integrations of wind power is much greater in West-DK than in East-DK, and is thereby of greater interest when focusing on exactly these issues. Does this mean that the results are disproportionate in relation to the total Danish energy system? No. The results represent problems occurring in the system today, and a system as we can expect it in 2025 (as the proposed installation of further wind turbines are in West-DK given that no other system changes are performed (see section 5.4.2).

In relation to the modeling of the energy system – today and with increased amounts of wind power - the unit commitment model was chosen. Besides from being a conventional model used for economic optimization of large power systems that consists of a series of production units, the unit commitment model is advantageous when it comes to including the restrictions of large power plants in the model (for further elaboration see Appendix 11.3). Several simplifications in relations to the real West-Danish energy system have been made in order to get feasible, yet applicable, results. These simplifications are further discussed in section 8.4.2. Nonetheless, a valid estimation of a power system equivalent to the West-Danish has been made, providing knowledge on the impacts of wind power on today's system as well as a future system.

8.2. The Challenges of 50 % wind power

The modeled scenario should not to be mistaken for a specific future scenario, as all other parameters (except from changes regarding flexible production) are held constant. Thus, an artificial scenario has been modeled with the sole purpose of analyzing the impacts from increased wind power, and the included changes, isolated. The results of the reference scenario basically reveal what kind of energy system behavior to expect if no means are taken – although 17 years passing by with no system changes made is highly unlikely.

As seen in chapter 4, already today, critical low prices occur – not only as a result of high wind production alone, but often with additional contribution from factors like cold periods, transmission congestions and low consumption. Especially the period of the day turned out to be a factor with significant influence on the probability of electrical over-supply. When holding the other factors constant at normal level, we saw how early-morning (from 3 a.m. to 8 a.m.) was highly significant in causing critically low prices (when compared to the reference period). Although there might be other explanatory variables influencing, we saw a probability close to 100 % of critically low prices when combining low demand, cold days and low external capacity (cf. the extreme situation in Figure 4.18). When looking further at the critical low prices, it was found that CHP units in the real system (when compared to the model) generally do not react to the market price by lowering the power generation. While part of this is due to smaller backpressure units usually operating by the tariff agreement (Ackermann 2005) other reasons could be lacking boiler capacity, block bids on El spot (only central units), or just plain conservatism among producers. This indicates, besides from the factors of relevance to over-supply, that there might be potential for decreased over-supply in flexible power generation.

When comparing the real system with the model results of the reference scenario subjected to the 2008 wind profile, it seems as if the central units in the model to a greater extend respond to the critically low prices, which could indicate the "market mechanisms" of the model being more effective than in reality, due to the real market having more limitations and being more complex. This implies that it might be possible to meet some of the challenges of increased power generation with changing of some of the ways in which the market is constituted today. An interesting observation made while comparing the modeled 2008-reference system to the West-DK system is that the total exported amount is higher in West-DK (around two times), but when comparing the total production during critically low electricity prices to the exported amount, the export is suddenly twice as high in the model, which could mean that sometimes, the announced export capacities in West-DK are lower than in the model (as shown in chapter 4). It has not been possible to include the factor of varying capacity announcements in the model, thus having to settle with a constant level of "allowed" import/export capacity. Although critically low prices currently only accounts for a small share of 1-2 %, the model results stresses the importance of effective congestion management in the future. The observed variations means that the optimization results of the different scenarios should be projected to the real system with reservations, as further discussed in section 8.4.

The results of the modeled reference scenario reveal some of the main challenges which we will face if no other changes to the system are made, when increasing the wind capacity according to 2017 and 2025. By 2017 the amount of critically low prices will increase by a factor of 8 (to 13 % share) on an annual basis, and by 2025 to a factor of 17 (29 %), when compared to 2008 (2 %). In addition, the average duration of these price periods are lasting 2 and 3 times longer in 2017 and 2025, which is an interesting development in relation to the mentioned lack of market response from CHP units. Therefore, if no system measures are introduced by the time the wind capacity reaches the level of 2017 and 2025, value will flow out of the system in the form of "free" electricity contributed by local heat costumers, a significant part of the year – something to be regarded as a great market problem. However, with the average duration of the critical periods increasing from averagely 5 hours in 2008 to 12 and 15 hours in 2017 and 2015, there could be a greater techno-economical foundation for adapting to the market situation. In this connection, the model results show a complete down-regulation (and sometimes decommitment) of power from central units within these longer critical periods, which indicates that no technical limits in theory are exceeded. When looking at the 2017- and 2025 reference scenario in general, it seems clear that operators of central units in the future will have to put up with a new role leaning more to the supplying of peak- and medium loads, than the traditional base load, if value is not to be lost.

It has been proved (chapter 6) that increasing heat prices from CHP units is a negative result of expanding the wind capacity in the reference scenario. Since the power generation costs in decentralized heat distribution areas (gas) are much higher than in the central areas (coal) the economic loss from the generated "waste electricity" increases correspondingly. Based on the larger potential for economic optimization in the decentralized heat areas, this thesis therefore suggests a prioritization of the rural – rather than urban – areas, in solving the problem of heat-constrained power generation.

In the constraint analysis of central extraction units, it was shown that, averagely two thirds of the time that the units are committed, the backpressure line of the units is constraining the optimal solution, indicated by the generation of shadow prices (see Table 7.12). This means that most of the time, power is generated in order to produce heat on extraction units. However, the share of constrained hours does in general not increase as the wind production increases to the 2017 and 2025 scenarios. But with a 300 % marginal efficiency on the extracted heat, it could seem natural for the model to maximize the combined heat and power supply by constantly operating in backpressure mode. The constraint given by the lower boiler output (Benson minimum) is generating twice as many hours with shadow prices in 2025 (40 %), which means that the power generation is attempted minimized more in 2017 and 2025 than in 2008, and that lower capacity therefore might be given more focus in the future than today.

As shown from the calculations of the revenues of the model results of the reference scenario, central units will experience an increase of 12 % and 27 % in 2017 and 2025 under the given assumptions. For comparison, decentralized CHP units will maximum loose 7 %, thus being highly insensitivity to the increased wind penetration. An insensitivity, which can be explained by the natural monopoly characterizing the heat supply, which in general characterizes the reference system's ability to integrate the increased wind capacity.

Finally, having analyzed the different aspects of the results from the reference scenario, what stands out, is that the two greatest obstructions to a successful integration of wind power (economically as well as environmentally) is 1) that wind power almost has no impact on the *heat* supply and 2) that a great amount of power generation is constrained by the particular heat production. As the main reason for the first problem is a lack of electricity-based heat production, the second is due to a lacking ability to separately produce heat, when heat needed, and vice versa. Both aspects are an expression of an *inflexible interplay* between the power and heat production, and a problem which especially characterizes the decentralized production. While the solution to the first can be an increased capacity instruments to connect the electricity and heat side, such as heat pumps and electrical cartridges, the second problem can be met by increasing the amount of pure heat production, such as boiling capacity and bypass of high-pressure steam turbines. On behalf of this, seen from a purely economic point of view, decentralized CHP units (backpressure units) should in general not be generating power in the future – except for in peak load situations and situations with zero wind (which can still happen in a 50 % wind power scenario).

Since the overall purpose of expanding the wind capacity is to increase the total share of renewable energy, an interesting consequence of doing so is that, because a large amount of the heat-constrained power generation is unaffected by the increase in wind penetration (particularly from decentralized CHP), the increased wind power will mainly compete with the external hydro production, which is regarded a RE source too. This means that, despite of the RE-contribution from wind power being approximately doubled between 2008 and 2017 the *total* share of RE at the same time goes from 28 % to just 32 % (see section 7.5.2). The two RE sources simply compete over the same supply capacity (see Figure 7.12 and Figure 7.14). Although this tendency could be enhanced by the low value of hydro, it still underlines a fundamental issue of wind power as a potential mean to achieve the political goal is no means are taken.

8.3. Flexible power generation as a way to meet the challenges

As implied above, one of the means that can be taken, in order to cope with the challenges of increased wind penetration, is flexible power generation. Heat pumps and turbine bypass have been selected for a further study of their economic and environmental impacts on the modeled energy system, as instruments for an advanced interplay between heat and power production. An alternative to heat pumps could have been electrical cartridges (resistors) which are regarded as cheap and effective in the short run (Energinet.dk 2009). However, with a low COP value of maximum 100 % electrical cartridges have been found slightly controversial (by the author of this report), and thus have not been considered included in the model and analyses, under given the time frame of this project. By controversial means that electrical resistors for heat production historically have been unpopular in relation to the Danish energy system, although the use of heat cartridges in some hours of the year could have a positive environmental effect (as seen in Figure 11.1, Appendix 11.2).

8.3.1. Turbine bypass

An optional bypass of the high-pressure turbine in central units has been examined in the modeling part. The BPO option have been modeled the simplest way possible, by letting the solver consider the choice: bypass – yes or no? This means that the plant will have to either produce heat alone, or co-generate – no middle-of-the-road operation.

The results of the bypass scenarios were interesting – especially in relation to the consequences of increased wind penetration. It was proved that, in windy periods, applying BPO to all extraction units can reduce the amount of critically low prices (from 69 % to 48 %), and increase the average electricity price without significantly reducing the average duration of these critical periods significantly. Additionally, the average heat price is reduced.

When analysing the total system economy, calculations of the full-scale BPO scenario shows a decrease in total costs of 13 % (in windy periods) compared to the reference scenario. That is a potential socio-economic gain of at least 1.4 million Euros a week, all things being equal. However, the crucial part of the economic aspect is whether the implicated central units would have prospects of economic improvements or deteriorations by applying the bypass opportunity. The modelled results generally indicate an improved economy for bypassed extraction units. In the full-scale BPO scenario, their income is averagely improved by at least[35] 6 %, the number of weekly start-ups is reduced to approximately one third, and the annual commitment factor increased to 91 %. That the total income is not worsened is an important finding as the BPO concept then not only is an economically good idea for the individual plant economy, but for society as well. The reduced number of start-ups is another significant finding as this might improve the operating conditions, considering the reluctance to frequent start-ups and shut-downs, and thereby reduces the amount of electrical overflow further. Finally, an interesting consequence of all units having BPO options is an equalizing effect in terms of annual load factors. When compared to the reference system, where three units have improved load factors and income due to the reserve capacity restriction, these numbers are more equalized in the full-scale BPO scenario.

In relation to the fulfilling of the political target of an increased renewable energy share of the final Danish heat and electricity consumption, the full-scale BPO system offers an increased RE share compared to the reference system, which mainly comes from an improved utilization of wind capacity based on the reduced central power generation. But the increased share of coal-related heat production has a slight back-side in that, the CO2 factor is greater for coal than Natural Gas, thus the total CO2 emission increases by ~2 %.

When subjected to the windy profile (~3000 MW mean), it was shown that extraction units operated with bypass most of the time in January and April, approximately half the time in November, but not at all in July. During the non-windy profile (~1000 MW mean) however, no BPO were selected at all. The results show that the right conditions for extraction units to produce heat alone is a combination of a low electricity prices and

[35]By *at least* 6 % is understood that, given the solution GABs of around 10 % (see appendix 11.4), the final solution might be more optimal.

a heat demand that is not too low. In fact, when the electricity price is critically low, it is often more convenient to operate in BPO mode while *oversupplying* the heat demand, than *balancing* it in normal mode (as a lesser of two evils).

The benefit of BPO does not require extreme wind conditions. In the single-unit bypass scenario it was seen how bypass mode is a convenient alternative to CHP given the current wind penetration level as well. During the 2008 profile, the extraction unit with optional BPO applied chose to “avoid” power generation the entire December and February, as well as most of November and April.

The quite frequent use of bypass as the most optimal solution prompts one to think of it as a suitable solution for an improved integration of wind power, thereby reducing constrained power generation. Despite of this, an improved utilization of wind power is not reflected in the results, due to the complete down-regulation of central production (see Figure 6.32). However, since it was ascertained that the model is more inclined to lower the central production (in favour of boilers) than what is seen in West-DK, the bypass concept may have a much greater wind-integration potential than immediately seen.

In a real steam plant there might be some technical issues associated with “switching” between BPO- and normal mode. For example, a problem to address is how much extra steam input the heat exchangers can handle, when considering the high energy-content of the steam that is normally used for driving the power generation (via the turbines). In practice (when looking at Figure 3.13), the steam plant will have to lower the boiler output to a level, that does not exceed the maximum heat capacity of the exchanger producing the district heating. In connection with the necessary large drop in production before entering BPO mode, a more detailed model could take the hourly ramp-down gradient of the boiler into account, thus generating a more accurate result. Another thing to consider is the possibility of a *partial bypass*, understood as an adjustable valve on the bypassing cycle, which might increase the flexibility further by instead, slightly changing the heat-electricity ratio.

As laid out many times, the results of the bypass is inhibited by the design of the heat distribution system of the model in that, the minimum boiler capacity of the central unit momentarily exceeds the local demand if operating in bypass. I strongly believe that if the model had included heat-storage mechanism (corresponding to the heat-accumulation tanks often seen in the real system), the value of bypass would increase further, due to an improved utilization in warmer months. However, further modelling and greater analysis are to be done in order to conclude further on the possibilities of PBO. Analyses, which in my opinion are of greatest interest in relation to further examination of this subject.

The most interesting aspects of alternately switching between CHP-operation and pure heat production, respectively, is that the shown economic improvements only reflects an improved central heat supply, while decentralized heat supply is unaffected. The results therefore indicate a further motivation for finding new ways to occasionally separate heat and power in decentralized areas as well.

8.3.2. Heat pumps

The heat pumps used in the model are all of the geothermal type with an estimated COP factor of 300 %. However, other heat pumps such as the air-to-air types (which are cheaper but with a lower COP factor of approximately 200 %), could also have been considered, as these can be installed in households – something which might help increasing the capacity more rapidly (Energinet.dk 2009). However, as the heat pump capacity in the model corresponds to a type of heat pump that responds to the market, the (large) geothermal type are the ones the model tries to capture the effects of. Feeding market signals to consumers on household level is nevertheless a relevant subject in this relation.

Compared to the bypass scenario, the inclusion of heat pumps in the modeled is a much more drastic modification of the system characteristics (given the selected capacities), when seen from a market- and investment point of view. The results showed that heat from decentralized CHP units cannot compete with the production costs of heat pumps at any time, while in the central heat-supply areas, heat pumps being in a more equal competition with extraction units as consumer-related electricity demand increases (see Figure 6.42). As a result of the strong competition from heat pumps within the heat supply areas, the total system cost is reduced by approximately 50 % in 2017 and further by 57 % in 2025, when compared to the reference system, indicating a potentially large socio-economic improvement from installation of heat pumps. Because of the variable costs of earth-heat being proportional to the corresponding electricity price, the increased wind penetration has a positive impact on the heat supply, contrary to the reference scenario, where the positive effects on the electricity price (from the increased wind power), is directly counterbalanced by an increasing shadow price on heat. As a consequence of the heat pumps introducing renewable energy to the heat supply, combined with the positive impacts from decreasing electricity prices towards 2025, the total share of RE goes from the 32 % and 35 % in 2017 and 2025, respectively, in the reference system, to 75 % and 81 % (Figure 7.13) in the heat pumps system. One of the reasons for this is the full utilization of internal wind production. Finally, the CO2 emission is reduced by almost half in 2025 compared to the reference system.

The different types of CHP units are affected differently by the heat pumps. While the income of decentralized backpressure units is completely reduced to a great extent, the income of extraction units is relatively unaffected, and due to the increase of heat pump-related consumption, condensing units are in this scenarios committed regularly. A negative consequence of this is a worsening of the total net efficiency from central production.

Normally, heat pumps are regarded an instrument for improved wind integration that can increase the internal electricity consumption, and an alternative to extending the external transmission capacity – a purpose which they (as the results clearly shows) manage to fulfill effectively by reducing the export significantly (see Figure 6.29). However, even with increased wind capacities corresponding to the 2017 and 2025 wind scenarios, windless days and nights occur, by which the wind production occasionally drops to a very low level, and as the heat pumps are still connected, the consequence is a maximum import within these periods, causing frequent congestions. The extent of these congestions is indicated by a very high bottleneck income from constrained *import* as seen during all three wind profiles (Figure 7.9). Ironically, heat pumps will thus not reduce the need for external capacities, but contrary expand it (given wet seasons in the Nordic hydro area).

Including a greater shortage on the water reservoirs in the model, could very well affect the costs of hydro, and thereby the results of the optimization – especially when recalling the large import rates in the heat pump scenario. Since the model includes a fixed, low costs on hydro generation (assuming sufficient water supply at all time), it is of concern, that the demand for coal-based electricity could increase intensively during more dry seasons, which then could affect the share of renewable energy and the CO2 emission significantly. A further analysis – that includes the impacts of increased heat pump-related electricity consumption on the costs of hydro – would therefore be of great interest in order to analyze if heat pumps as a consequence revives coal-based steam units. Besides from that, the results of heat pump scenarios clearly suggest that heat pumps (rightly) should play an important role in order to achieve the political target of 50 % wind power, as well as an effective utilization of the increased wind capacity. It has been shown, that the main reason for this is due to their ability to transform (renewable-based) power into renewable heat, making the CHP-based energy systems much more flexible.

8.3.3. Flexible production versus flexible consumption

As shown in this thesis, there is no doubt that some kind of means is necessary if the advantages of increased wind penetration are to exceed the disadvantages. In this section the advantages of flexible production versus flexible consumption is discussed.

In this project, flexible production (or flexible power generation) is understood as a way to lower the power generation while maintaining the heat production, thereby reducing the constrained power and thus increasing the utilization of wind power along with its value.

In a report published in 2009 on effective utilization of wind-based electricity, the Danish TSO finds it necessary to develop a more intelligent and flexible power system (Energinet.dk 2009) in order to cope with the increasing electrical spillover as well as to increase the value of wind power. In the report, the suggested means are primarily based on creating *new* large flexible electricity *consumption*, mainly in the form of heat pumps and intelligent charging of electrical cars. In this project, flexible consumption has not particularly been examined – except (of course) from the heat pump consumption. It is my persuasion however, that flexible *production* contains greater potential and it does not directly depend on involving consumer behavior as a flexible factor.

As described earlier, extraction units have a tendency of down-regulating production much more in the optimized model, than experienced in West-DK (particularly in critical hours). In addition, we saw how extraction units by 2017 and 2025 often would operate at a their minimum production limit for several hours, and sometimes even de-commit, without compromising the physical gradients and other constraints – something which is only possible via the sufficient amount of boiling capacity, naturally. Due to this flexibility already present in the reference scenario, the utilization of wind power in the bypass scenario was not improved as much as expected, given the rather limited optimization potential. The model results therefore indicate a potential of increased flexibility, already contained by the present system.

In the resent years, much has been said about the necessity of heat pumps, electrical cars, and other tools for increased flexibility. While planning large investments into a more advanced network of the future, this project suggests a simultaneously conduction of further studies of the different obstructions causing the inflexibility behind the heat-constrained power, based on the flexibility of extraction units seen in the modelled reference scenario of the project – obstructions which could be market-related as well as technically founded. And then, as a further step, a study into the concept of turbine-bypass is suggested based on the positive economic results found in this project – especially when seen from a plant-owner's perspective. The results of this project fundamentally support the thesis that heat pumps should play a large role in the future energy system due to their ability of producing *renewable heat,* and even today, steps in this direction should be taken before changing the entire system (which to some extent is required in order to incorporate electrical cars for example). However, as the results obtained from the modelled heat pumps scenarios indicate, an increased demand for coal-based power by might develop in this system, and the report stresses the importance of further studies into the corresponding role of central units in the future in relation to CO2 emissions. However, flexible *production* is easy to implement and does not rely so much on change of attitude among the general consumer.

8.4. Validity of the results

8.4.1. Statistical data

Data used for the analysis is first and foremost data from the Danish TSO on the West Danish energy market, ranging from 2004 to 2009 (the corresponding heat data covered only 2001), and data on the power units from 2006 (see section 4.1 and 5.4.1). By using five-year data for the analyses, the variations from year to year in for example temperature and rainfall are evened out, and extreme data are included but are not critical to the results. Furthermore, the five-year data provide an excessive amount of data – more than 40,000 observations – which provide a better data basis for the calculations. The accuracy of the estimates of the relation between critically low prices and the explanatory variables (section 4.5) increases as the number of observations increases, and the mean values used to demonstrate the impact of wind power on price formation (section 4.2), are less affected by outliers than with a lower number of observations.

8.4.2. The unit commitment model

As mentioned at the beginning, several simplifications has been made in order to be able to model the impacts of wind power today as well as in a future scenario with increased wind capacity.

It has been stressed earlier on that the model optimizes the energy system as if there were only one producer (owning all the utilities) trying to minimize the total system costs. The results, however, apply to a market system where an infinite number of producers are price takers with no ability to manipulate the market (for further elaborations on this see section 5.2.4). As these ideal market conditions do not characterize the West-DK system (where a large part of the production is owned by two companies), the results are expected to deviate a bit from a real system, in that the total cost of the system is a bit underestimated. Although this may add a level of uncertainty in relation to a real market system, the results are still a good approximating when regarding this. In relation to this, another market characteristic of the modeled system, distinguishing it from the real, is the ability to "perfect foresight" – weeks and months ahead. A perfect example of this is the wind production. Where the exact quantities in the model are known for the entire sequence, the real system will have to rely on uncertain prognoses. This affects the analyses based on the more fine distinctions of the result. This however, does not mean that the results are not applicable to a real market and power system, but just that relatively small variations in the modeled results (of a few percentages) are not that reliable to base the final conclusions on. When it comes to the modeling of external capacities, simplifications have been made too, so that only the interplay with the Norwegian (and Swedish) hydro production is reflected. In West-DK, export to Germany normally accounts for at large share of the annual rates of import and export and West-DK often plays the role as "transit country", transmitting power from Norway to Germany in times with abundance of hydro (and sometimes the other way around during windy hours in North Germany). This simplification was also made in order to regard the frequently lack of ability of the German power system (EEX) to receive power in windy times (see Figure 4.19). An action which may reduce central productions on an annual basis, but which was made, as the one of the greater focus areas of this project is critically low prices. Furthermore, the Danish coal power plants are quite competitive in a European perspective; hence it can be argued that the modeled results reflect a lower demand for cogenerated power than expected in the West-DK system. Therefore, when concluding on the basis on the total values in relation to West-DK, the actual thermal power production, plus imported amount, may be larger due to a regularly large export to North Germany (Table 3.2).

A strong simplification has been made within the heat markets as biomass as a source for heat has been neglected. In the Danish district heating-systems, Biomass normally constitutes around one third of the heat production (Energinet.dk 2009). As a fuel, Biomass approximately costs the same as Natural gas but the production is more than seven times higher (Ea Energianalyse 2006). In the model, the variable costs of biomass have been assumed identical with Natural Gas, and the biomass-facilities are included as boilers in both central- and decentralized areas. Environmentally, the results of this simplification may differ from the real system, by disregard the CO2 neutral bio fuels, but the market characteristics are (roughly) maintained. Heat from waste incineration is excluded too due to being relatively insignificant in relation to production size as well as lack of market impacts.

When it comes to the bypass scenario, we saw how the complexity of the full-scale bypass scenario resulted in gaps on the final solution of around 6-10 % (see Table 6.2). However, this relatively high uncertainty of the modeled result, may not be not be much different from the earlier mentioned uncertainties, from comparing the optimization model (with perfect foresight a week ahead etc.) to a real system based on limited forecasts.

8.4.3. The importance of optimization modeling

The model is based on the West-Danish energy system. Although many simplifications have been made on various parameters, ranging from energy prices to physical and environmental characteristics, the modeled approximation of the impacts are of great relevance to the evaluation of a future Danish power system with 50 % wind power, in that the results reflects the fundamental dynamics of the current system. The formulated unit commitment model has been a good tool for answering the stated objectives.

Despite of a few suggested modifications, the unit commitment model of this project has been successfully designed with the ability to provide results that highlight the problems contained by the 50 % wind power, as well as to assess the potentials of turbine bypass and heat pumps (economically as well as environmental). Meanwhile, by focusing mainly on significant system characteristics (e.g. technical properties of large central units), the final detail-level of the model has been well balanced between, on one hand, being highly accurate (and compute heavy), and on the other, being very simple and less accurate.

Chapter 9.
Conclusion

By year 2025, 50 % of the Danish power generation is to be supplied by wind power as a result of the commitment of the Danish government to a target of 30 % of energy from renewable sources by 2025. In an energy system like the Danish heat and power system, the amount of wind power is not further increased without causing some difficulties, as the rather inflexible interplay between wind power and thermal power generation already today causes electrical overflow. The primary objective of the present thesis has therefore been to examine the economic and environmental impacts of wind power on a CHP based energy system similar to the West Danish, under the influence of the wind capacity of today, as well as under influence from increased wind capacity from approaching the 2025 target. In order to do so, knowledge on the Danish energy system was required, and the objective has been reached through a review of the Danish energy system, a statistical analysis of the impact of wind power on price formation and production patterns today, and finally; through modeling of the effects of 50 % wind power by formulating and optimizing a unit commitment model designed for fulfilling the project objectives.

When defining the input parameters of the model, the characteristics of the West Danish energy system were used. Furthermore, two instruments for advancing the flexibility of the interplay between heat and power production – heat pumps and turbine bypass – have been examined in order to discuss possible initiatives to cope with the challenges of the 50 % wind power. This has been done through comparison of the modeled reference scenario (the system as it is today), the bypass scenario (similar to the reference system except that all extraction units have optional bypass) and the heat pump scenario (similar to the reference system but with heat pumps), all subjected to three different wind production levels: a 2008-level, a "halfway"-level corresponding to 2017, and finally a 2025 wind production level, marking the political target.

Regarding the impacts of wind power on the West Danish energy system of *today*, it has been shown that the probability of electrical spillover increases as the wind production increases. However, wind power is not the only factor causing electrical overflow. Other factors such as waning electricity demand, cold nights, Nordic rain, and reduced interconnection capacity all increases the probability of critically low electricity prices – especially when combined. Furthermore, as CHP units do not seem to respond to critically low prices (by down-regulating the production) a significant amount of heat-constrained power generation contributes even further to the probability of critically low electricity prices – hence the electrical spill over.

When analysing the modelled impacts of *increased* wind penetration the following were found: In the reference system, it was seen that both the *amount* of critically low prices (from electrical spill over) and the *duration* of these low-price periods increases significant as a result of expanding the wind capacity towards 2025. Simultaneously, the marginal heat-costs of CHP-units increase as a result of the economic loss from the increasing occurrence of constrained power generation. However, from the optimization of the system with turbine-bypass it was seen that the applied optional bypass to some extend reduces the electrical spillover, and it can generally be said that the BPO-option helps balancing the falling electricity prices and the increasing heat prices. In the heat pump scenario, it was found that including the heat pumps also has a balancing effect on the formation of heat and electricity prices, while leveling out the price differences observed in the reference scenario. When comparing the two flexible instruments, heat pumps had the largest impact on the shadow prices of heat- and electricity.

Regarding *power generation*, one of the main findings of the reference scenario was that the extraction units down-regulates, and to some extend even de-commit, as a result of the increasing wind capacity. The modeled system however, seemed more flexible regarding integration of wind power than the West Danish when comparing the two. It was thus concluded, that the current West-Danish system already contains a potential for increased flexibility in form of a more optimal scheduling of production. Furthermore, the quantity of exported power as well as the surplus wind capacity increases concurrently with increased wind production, putting a pressure on the external transmission capacity, as seen from the increasing bottleneck income. It was shown that optional bypass is mostly suited for cold and windy times, while heat pumps are competitive even through non-windy periods. Heat pumps thus contain a potential of increasing the import from the hydro-areas as well as the demand for coal-based power.

For the reference scenario, the picture is almost the same regarding *heat production*, as the extraction units in this scenario down-regulates as a result of the increased wind capacity also – at least during cold periods. In the bypass scenario, it was shown that almost the entire heat production was produced on extraction units; but at the same time it was argued, that it is hard to determine the heat price on the basis of the model result, due to an error from oversupplying the heat demand causing of revenue loss from the corresponding price formation. When applying heat pumps, heat is almost solely produced on heat pumps in decentralized areas and, and as the wind increases, to a greater extent in central areas as well, showing that heat pumps often are the most economically optimal heat supplier.

When looking at the impacts from increased wind power *on single power plant economy*, it can generally be said that the economic situation of the central units is worsened as the wind capacity increases towards the 2025 wind scenario in the reference system, while the income of decentralized CHP units is relatively unharmed by the change in wind capacity. It was shown that optional bypass had a slight positive effect on the individual plant economy, as well as on longer commitment and fewer start-ups. Bypass operation (BPO) is generally assessed optimal during combined cold- and windy periods, and when applying BPO in full-scale, BPO was furthermore shown having an equalizing impact on the load factors of extraction units. In this connection it has been argued that the observed positive effects might even be greater than estimated here, due to the limitations from momentarily having to balance the heat demand, and not having any heat-storage options in the model. It has therefore been assessed that the inclusion of accumulation tanks likely could reduce the BPO-caused oversupply problem, thus improving the plant economy further. Opposite to the BPO-system, heat pumps in general have a negative impact on the individual power plant economy – except for condensing units, which are likely to experience a revival if this scenario is implemented. Units with a more heat-producing purpose however (such as backpressure- and boiler units) will be economically harmed the most, as they are being completely replaced by the heat-supply of heat pumps – this, of course, when optimizing from a system point of view.

When observing the *total system costs*, the increased wind penetration is shown having different impacts in relation to reduction in total system costs, when comparing the reference, heat pump and the bypass scenarios. Differences existing therein that the total costs of the reference system were highly insensitive to the increasing wind capacity of 2017 and 2025, while the heat pump and BPO systems experienced reduced total costs. It was found that the key factor for reducing the total costs given increased wind capacity, is increased flexibility plus the possibility of letting the electricity (and thus the RE production) gain impact on the rather constrained heat-supply of today. As both BPO and heat pumps raises the electricity price (while lowering the heat price), the two instruments have an indirectly positive impact on the value of wind power – an economic gain indicated by a change in the shadow prices.

When it comes to the *environmental impacts* – which can be said to be of most relevance to the purpose of increased wind power – it is found that if no means are taken, the increase in wind capacity alone will only result in a slight increase in the share of renewable energy when it comes to power generation, but none, when it comes to heat production – an increase, which is higher in both the heat pump and the bypass scenario.

However, the total CHP efficiencies of the heat pump scenario will drop as a result of increased demands for condensing electricity, which ultimately worsens the CO2 factor – relatively seen. Nevertheless – as the heat pumps scenario has a significantly lower CHP-production on a total basis (due to improved wind integration and large import of hydro power), the total CO2 emission from the heat pump system still has been found lower than in the reference and BPO system. Moreover, the CO2 emission in the windy full-scale bypass scenario is slightly greater than in the reference scenario, as a result of coal-based extraction units replacing the gas-fueled boiler capacity. Finally, a further study of the environmental impacts from heat pumps was suggested since the low value of hydro assumed in this model is likely to have covered up a potential increase in coal-related power generation.

It was generally found in the results, that heat pumps have a positive effect on the environmental impacts of increased wind penetration as well as on the prices on heat and electricity and on the production patterns. So does bypass operation (except from when it comes to CO2 emission) and it has therefore been argued that flexible production, in the shape of optional bypass and heat pumps, are good instruments for meeting the challenges of 50 % wind power. Furthermore they are simple alternatives to flexible *consumption*, which depends on consumer behavior plus an advancement of the technological level of the power system.

The formulated unit commitment model is not to be regarded as a exact approximation of the West Danish energy system, but an approximation to *a system with similar characteristics*, and the results are thus to be interpreted with awareness of the dynamics of the energy system of today, as well as of the system with increased wind power, and thus not as a *forecast* of the future. However, since the model is based on the West Danish energy system and calculated on basis of data contained within here, the model provides results that highlight the problems connected to the 50 % wind power, as well as an assessment of the potentials of turbine bypass and heat pumps in the Danish energy system.

All in all it can be concluded, that if the wind power increases to 50 %, significant changes in relation to price formation, production patterns, and single power plant economy, as well as the total system costs and green accounting, will occur, and if no means are taken, the great intentions related to increasing the share of wind power will be gone with the wind.

Chapter 10.
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10.1.3. Personal contact

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Chapter 11.
Appendix

11.1. Logistic regression – validity of the regression model

In chapter 4 the relation between critically low prices and wind production, demand, decentralized production, central production, hour of the day and total allowed external transmission capacity was modeled using the logistic regression model. In this section the validity of the estimated model will be discussed.

The estimated probability model is:

$$P(Y = CLP) = \frac{\exp(5.837 + 0.228 wind + -0.494 demand + 0.221 decentralized + -0.065 central + hour + -0.089 capacity)}{1 + \exp(5.837 + 0.228 wind + -0.494 demand + 0.221 decentralized + -0.065 central + hour + -0.089 capacity)}$$

11.1.1. Likelihood ratio and Wald test

The likelihood ratio test evaluates whether or not the set of the independent variables improves prediction of the dependent variable better than chance. Testing the full model against the empty model and thereby testing whether at least one of the independent variables is statistically different from zero. The likelihood ratio is reported as -2logL(ikelihood) (since the likelihood values ordinarily are very small) and is distributed as chi square (Agresti & Finley 1997: 581-82):

$$-2\log\left(\frac{L_{full}}{L_{empty}}\right) \sim \chi^2$$ with df (degrees of freedom) = number of variables in the full model

The Likelihood ratio test is highly significant (p < 0,000) which means that our model fits significantly better than the empty model.

The Wald test provides similar evidence by testing if the estimated beta weight is significantly different from zero (for further elaboration see Agresti & Finley 1997: 581-82).

$$wald = \left(\frac{b-0}{SE(b)}\right)^2 \sim \chi^2$$ with df = number of parameters tested to be equal to zero

All weights in the model are statistically significant (different from zero).

11.1.2. Hosmer -Lemeshow test

The Hosmer-Lemeshow test is an absolute measure to assess whether the predicted probabilities match the observed probability – the goodness of fit. By partitioning the observations in ten equal sized groups according to their predicted probability it is tested if the model predict the equally well for all ten groups.

$$Hosmer - Lemeshow = \sum\left(\frac{observed - predicted}{predicted}\right)^2 \sim \chi^2$$ with df = 8

The test is highly significant which means that there is incongruence between the observed and the predicted values. This might be a result of the great number of observations in the dataset (43,848), thus being less of a problem.

11.1.3. Assumptions

Although logistic regression makes fewer assumptions than linear regression, logistic regression does require the fallowing:

1. There must be an absence of perfect multicollinearity
2. There must be no specific errors (i.e. the relevant predictors are included and irrelevant predictors are excluded)
3. The independent variables must be measured at the summative response scale, interval or ratio level (although dichotomous variables are also allowed).

   (Meyers, Gamst & Guarino 2006: 222)

To begin with the latter, all the independent variables, except for *hour* which is categorical, are either interval/ratio level.

Multicollinearity refers to a situation where two or more explanatory variables in a regression model are highly correlated, thereby affecting the estimation of the predictors. We have perfect multicollinearity if the correlation between two independent variables is equal to 1 or -1. There is absence of perfect multicollinearity in the model although some of the independent variables correlate (for example *hour* and *decentralized* or *hour* and *demand*). This is not considered a huge problem since the change in the estimates is relatively small when subtracting on of the variables from the model plus the multicollinearity is considered of the "good kind" where the variables measure something different (theoretically – and in practice in this case).

Regarding the assumption of no specific errors, it has been tested of other variables should be included in the model, or if data should have been recoded differently, by testing the distribution of the conditional means of the standardized residuals on included as well excluded variables. However, this was not the case.

11.2. How much of the heat supply from heat pumps is renewable energy?

In chapter 7 it was argued, that only two thirds of the heat supply from heat pumps (earth heat) can be regarded as pure RE sources, while the third part (electricity) cannot. In figure Figure 11.1 below the distribution of sources for the electricity used by the heat pumps is seen. It shows that when subjected to the 2008 wind capacity, two thirds of the electricity comes from RE sources (when including import). In 2017 and 2025, this share has increased to around 75 % and 81 %, of which wind production represents 44 % and 58 % of the consumed electricity, respectively. On basis of these results, it can be questioned whether the electrical part of the heat supply should be regarded as non-renewable energy.

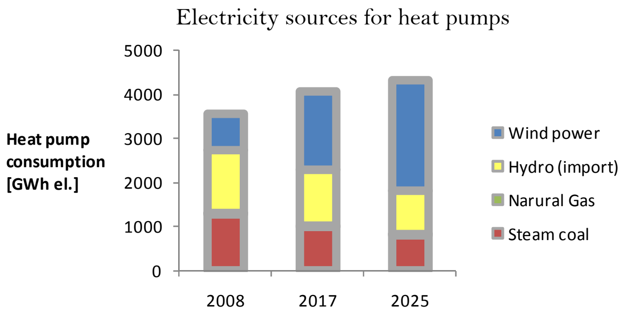

Figure 11.1, A further look into the distribution of energy sources constituting the power supply of heat pumps.

11.3. The Unit Commitment Problem

This section contains additional explanation and graphs on the solving of the unit commitment problem.

11.3.1. Optimizing the Unit Commitment Problem

The fundamental task, when optimizing the unit commitment problem, is to minimize the overall costs of the system. The overall costs are given by the stochastic objective function $C(e^t_i,h^t_i)$, where e^t_i and h^t_i refer to electricity and heat, meaning that the total cost depends on both of these parameters when modeling power systems with co-generating units (Ravn 2001). Here, the index values i and t denotes the particular *unit* and *hour* of operation, respectively.

A fundamental part of optimizing the unit commitment problems is to perform linear optimizations of the total cost function C, subjected to a set of constraints that express different conditions or boundaries. In Figure 11.2, which presents this in a very simplified way, the optimal solution x and y of $f(x,y)$ is found within the convex solution space A by maximizing function $f(x,y)$. When subjected to a constraint function – an inequality for example – the optimal solution is to be found within the convex solution space B instead. The constrained solution therefore is the equilibrium of a series of restrictions. (Bregnbæk)

The solution to a simple optimization problem can be found analytically by use of the Lagrange Multipliers. As further constraints start complicating the problem, mathematical software can usually solve this more easily through iterative processes.

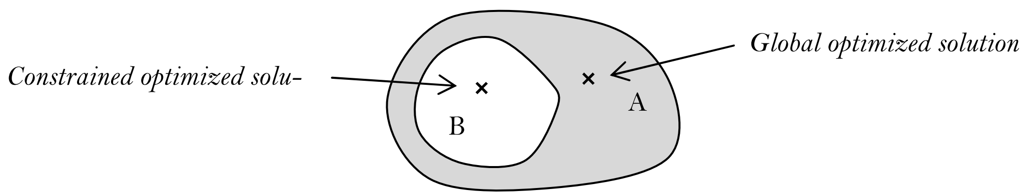

Figure 11.2, A principle sketch of the optimal solution. If the global optimized solution happens to be in A, then the solution found in B in this case represents the second best optimum. If not, the applied constraint does not affect the outcome and the 'system' in balance.

When it comes to finding the optimal combination of committed capacities, the method used for mathematically committing and de-committing production capacities, is for each time step t to introduce a set i of binary variables $x_i^t = \{0;1\}$, where x_i^t is a positive integer with the property of assuming the two values; zero and one. This way, capacity i is committed when $x_i = 1$ and de-committed when zero. Figure 11.3 shows the principle here.

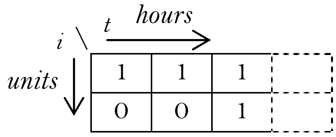

Figure 11.3, the variables: time and units forms a T x N matrix (T being the optimized period and N the number of units to commit (1) and de-commit (0), respectively.

The key task then is to figure out an optimal combinatorial solution of committed plants. Not just for the specific hour, but for the entire optimized period of operation as well, since a number of parameters can influence the optimal combination of committed capacities over time as a total. One of the big difficulties of optimizing these types of problems is that the region of feasible solutions no longer is constrained by a series of linear constraint functions alone, but additionally being subjected to a set integer constraints, which ultimately results in a solution space that no longer is convex[36] (Wikipedia, Linear programming) (see Figure 11.4).

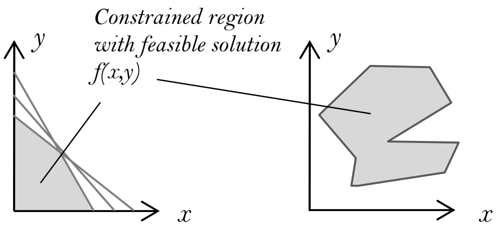

Figure 11.4, As the graph to the left illustrates a convex solution area solvable by regular linear programming, the right illustrates a linearly insolvable concave (non-convex) area which is usually produced when adding binary constraints.

Because the unit commitment problem often is mathematically stated as a combination of rational (often positive) variables on one hand, and binary integer variables on the other, which makes the optimization problem non-convex by having multiple locally optimal points, a feasible solution can sometimes be found via Mixed Integer Programming (MIP). The methods of MIP can be described as finding the best solution – linear or non-linear – of each possible 0–1 combination. Characteristic for MIP programming is the generation of a number of sub-problems which are to be solved by an additional number of linear optimizations. However, one of the biggest problems with MIP is that as the number of possible 0-1 combinations increases – so does the computations time and physical memory required for the task – exponentially (GAMS 2007).

Feasibility is yet another problem with this method. MIP problems have feasible solutions if, and only if, the constraint matrix on left hand side is fully unimodular as well as the right-hand sides of the constraint functions being integers (Wikipedia Linear Programming). In practice, this means that the decision variables of stated unit commitment problem, this being e.g. the power generation of the units, never must be constrained from assuming zero.

11.3.2. Solving the Unit Commitment Problem

In the section above, the possibility of solving the unit commitment problem by Mixed Integer Programming (MIP) was described. I this section some of the main procedures, connected to the MIP solving of the optimization problem defined in this project will be described.

---

[36] In the concave solution space, one can no longer linearly connect all points within the constraint area (Eising 1999).

It was previously mentioned that, given the available modeling tools used for this project, the solving process, which normally is considered a programming-heavy part, only will be explained in principle in this project. This section will therefore be a more or less intuitive and practical introduction to the basic principles behind the methods used by the solver applied for the optimization.

Searching, Branching and cutting

At first, when a solution space to the root problem is found by the solving algorithm to be restricted by integer-constraints, and it thereby becomes concave, the root problem is divided into two sub problems from the 0-1 variable. This process proceeds, and eventually, as seen in Figure 11.5 below, a tree structure is produced, or *branched*, according to the number of applied integer constraints causing non-convex solution spaces. The search only stops when until the optimal solution space emerges. Usually, the tree size increases dramatically along with the applied number of time steps wanted for the simulation, but the exact scope of this varies a lot[37].

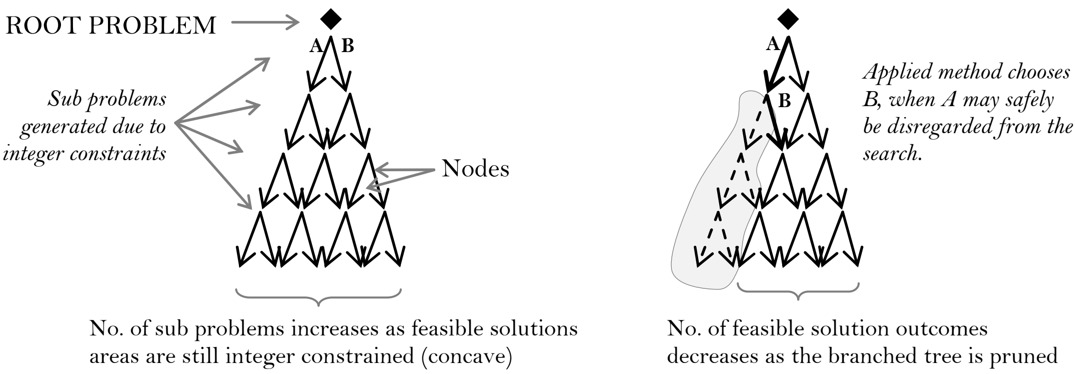

Figure 11.5, Left: Branching - a tree structure emerges from the number of 0-1 variables that still constrain the solution space. Right: Cutting: the applied algorithm cuts way possible solutions that safely can be disregarded from the search.

Now, each possible path down along the nodes of the tree structure represents a linear (or non-linear) sub-problem to be optimized. The applied MIP algorithm first finds the global optimal solution of the root problem (via standard linear or non-linear optimization methods) by *relaxing* the integer constraints (Solver 2009). When this is done, it checks to see if one or more integer variables have non-integral solutions (hence the concave solution area), and if so, sub-problems A and B are created as shown above. These sub problems are then solved and the non-satisfying solutions are cut away. This procedure continues until a solution satisfying all constraints are found. Sometimes the number of tree nodes becomes too comprehensive, and one would have to settle with a devia-

[37] The complexity, and hereof branched tree sizes, varies a lot from simulation to simulation. Sometimes, with a given set of input data, one can be lucky to have a balanced optimization with fewer created sub-problems.

tion given by the gap between best possible solution found and the overall optimal solution.

The described optimization usually starts out with a heuristic search algorithm that uses a Branch and Cut method. Branching, which means defining the tree structure and cutting, to safely "cut" away the nodes not representing an optimal solution, and thus *prune* the solution outcome. It is often the case, that a single MIT problem can generate a great amount of sub-problems, which quickly turns the modeling into a compute intensive process that requires a great amount of physical memory as well (GAMS 2007).

11.3.3. GAMS/CPLEX

As mentioned in chapter 5, the mathematical tools used in this project for solving the unit commitment problem is a combination of the modeling language GAMS and the MIP solver Cplex, respectively. Regarding the model language, GAMS operates in general with sets, indigenously and endogenously sizes which in normal terms best can be interpret as indexes, variables and scalar items, respectively. One of the greatest advantages of this particular tool, in connection with the current project, is that it from the beginning has build in different types of variables such as positive variables, integers and binary variables. Especially the use of positive variables is a factor that trims down the programming language as well as heavy computing processes. Another advantage is the rather easy use of tables and vectors in combination between indexes (for example (i,t)) and input parameters (scalars).

Since GAMS is mostly a programming language, the code is also used for "calling" the specific solver to perform the desired optimization. This way, GAMS translates the stated mathematical problem for the user into the solver's language. When it comes to picking out an appropriate solver for a specific assignment a great selection of different tools is presented - varying from simple linear programming-solvers (LP) to more advanced ones. When choosing the solver, it is important to carefully consider what particular type of problem is to be optimized, avoiding greater complexity than necessary[38] – especially since the solvers more often than not are quite expensive (although GAMS as a tool is free of charge).

The solver chosen for this project is Cplex, due to its efficient MIP optimizing, and the fact, that an academic software license for Cplex already was available through the university.

[38] Sometimes, a small simplification can mean the difference between a simple linear problem (LP), and an advanced non-linear (NLP) or a NLPEC, MPEC, MSNLP and so on.

11.4. Optimal GAB sizes from GAMS/CPLEX

In this section further tables on the necessary limitation of the solving process given by the solution gaps are presented.

Solution Gaps on the modeled reference system

GABS	2008	2017	2025
January	0	0	0.005
February	0	0.02	0.005
March	0	0	0.005
April	0	0	0
May	0.02	0.001	0.005
June	0.015	0.03	0.005
July	0.025	0.09	0.025
August	0.025	0.02	0.015
September	0.00015	0.01	0.005
October	0.005	0.01	0.005
November	0	0.01	0
December	0	0	0.005

Solution Gaps on the modeled bypass system (single unit)

GABS	2008	2017	2025
January	0.75	1.41	1.32
February	1.48	1.44	1.47
March	1.29	1.42	1.47
April	1.47	1.5	1.49
May	1.33	1.49	1.45
June	0.79	1.11	1.15
July	1.26	1.05	1.20
August	1.05	1.38	1.36
September	0.86	1.45	1.23
October	1.32	1.39	1.47
November	1.47	1.47	1.41
December	1.43	2.48	4.22

11.1, Gap sizes restraining the optimal solution in the reference and the bypass scenario.

11.5. The formulated GAMS model

In this section the code for the formulated GAMS model is presented.

11.5.1. Code for the formulated GAMS model for the Reference and bypass scenario

```
$Ontext
This script models a simple Unit Commitment (UC) problem using combined Mixed
Integer Programming (MIP) and Linear Programming (LP) programming, by dualizi»
ng
the multiple choise constraints with an integer x=[0;1] - also known as binar»
y
varible.

ifm. bpo:

1) ud(i)    for alle udtagsværker uden BPO (By-Pass Operation)
2) bp(i)    for alle BPO-værker
3) alm(i)   for ALLE værker (både ud og mt) UDEN BPO
$Offtext

sets
  i      generator /G1*G11/
    ud(i)  extraction units without bp /G8*G10/
    udh(i) extraction units with heat /G1*G7/
    mt(i)  back pressure /G11/
    bp(i)  bypass units /G1*G7/
    res(i) reserve units /G1*G9/
    alm(i) all units without bypass /G8*G11/
    cu(i)  all centralized units /G1*G10/
    dcu(i) all de-centralized units /G11/
  t      time /t1*t168/
  gchar  Gen. unit characteristics /fc,Pmin,Pmax,Pst,cv,cm,Hmax,st,RR,elv/

Binary variable
         x(i,t)          asignment of Gi at t
         st(i,t)         start-up indicator 1 only if  0-1
         b(i,t)          turbine bypass of Gi at t

Table gdata(i,gchar) unit fc and cap. limits

      fc   Pmin Pmax  Pst   cv     cm   Hmax   st    RR    elv
G1    125   80  400   450  -0.15  0.75   450 10000  200    0.47
G2    125   70  350   450  -0.15  0.75   450 10000  200    0.47
G3    125   70  350   450  -0.15  0.75   450 10000  200    0.47
G4    125   80  400   450  -0.15  0.75   500 10000  200    0.47
G5    125   50  250   450  -0.15  0.75   350 10000  200    0.47
G6    125   80  400   450  -0.15  0.75   475 10000  200    0.47
G7    125   80  400   450  -0.15  0.75   450 10000  200    0.47
G8    125   50  250   400    0     0       0 10000  200    0.50
G9    125  130  650   600    0     0       0 10000  200    0.50
G10   210   0   1000  4000   0     0       0  0     10000  0.42
G11   210   0   10000 4000   0    0.55 10000  0     10000  0.90
```

```
scalars
  Pres   min. reserve capacity demand limit       /1/
  Pdx    demand in area 2                          /3000/
  P12max max. capacity on interconnection          /1200/
  M      very large number                         /10000000000/

* Reading profiles for el, heat and wind
$include 'El_demand.inc';
$include 'Heat_demand_c.inc';
$include 'Heat_demand_dc.inc';
$include 'Wind_profile.inc';


Positive variable
  P(i,t)          Boiler power (for total fuel costs)
  Pel(i,t)        El. output at G(i)
  Ph(i,t)         Heat output at G(i)
  Pw(t)           Wind power generation
  Px(t)           Power generation in exchange area (hydro primarily)
  Php(t)          Heat pump - capable of transforming el to heat.
  Pbc(i,t)        boiler power in central area i
  Pbdc(t)         Boiler power in de-central area
  Pchp(i,t)       chp prod. in area i
  Pelc(i,t)       el from chp's in central areas

variable
  c               total costs
  c2              total costs per hour
  stt(i,t)        TEST - start-up costs of G(i)
  p12(t)          power exchange
;

Equations
  costeq            total cost calculation (both systems)
  demcon(t)         satisfy el. demand constraint
  demconh(i,t)      satisfy heat demand constraint (central units) at i
  demconhd(t)       satisfy heat demand constraint (de-central units)
  demconx(t)        satisfy el. demand in exchange erea
  wcon(t)           max. wind level
  boiler_ud(i,t)    constraint for el-heat factor of Gi's boiler (extraction)
  boiler_mt(i,t)    constraint for el-heat factor of Gi's boiler (modtryk)
*$ontext
  boiler_ud_bp(i,t) constraint for el-heat factor (bypass)
  boiler_bp(i,t)    constraint for heat from bypass of Gi
  bp_con_bp(i,t)    Back pressure constraint
  elh_conmin_bp(i,t) min. electricity-heat constraint
  bypass_el(i,t)    no el. when bypass -constraint
  bypass_min(i,t)   min. boiler power at bypass
```

```
*$offtext
  elh_conmin(i,t)    min. electricity-heat constraint
  elh_conmax(i,t)    max. electricity-heat constraint
  bp_con_ud(i,t)     udtags-constraint
  bp_con_mt(i,t)     Back pressure constraint
  bp_con_mtC(i,t)    back pressure constraint for central chp's
  st_up(i,t)         is G(i) starting ab at t Uhr?
  st_test(i,t)       TEST: how much is the fish?
  spinres(t)         eq for spinning reserve capacity
  ramp_cons(i,t)     eq. for ramp constraints
  capcon12(t)        upper exchange capacity limit
  capcon21(t)        lower exchange capacity limit
*  x_reserve          water reserve limit
 heat_up(i,t)        upper heat constraint
 heatpump(t)         max power from heat pump
 boiler_c(i,t)       boiled water for heat peak load in central
 boiler_dc(t)        boiled water for heat peak load in de-central

;


* --------------- eq. exe --------------------------- *


* El./heat constraints
boiler_ud(i,t)$ud(i)..          P(i,t)   =e= Pel(i,t)/gdata(i,"elv") - gdata(i»
,"cv")/gdata(i,"elv")*Ph(i,t);
boiler_mt(i,t)$mt(i)..          P(i,t)   =e= (Pel(i,t) + Ph(i,t))/gdata(i,"elv»
");
bp_con_ud(i,t)$ud(i)..          Pel(i,t) =g= gdata(i,"cm")*Ph(i,t) ;
elh_conmin(i,t)$alm(i)..        Pel(i,t) =g= gdata(i,"cv")*Ph(i,t) + gdata(i,"»
Pmin")*x(i,t);
elh_conmax(i,t)..               Pel(i,t) =l= gdata(i,"cv")*Ph(i,t) + gdata(i,"»
Pmax")*x(i,t);

*$ontext
* BYPASS CONSTRAINTS
boiler_ud_bp(i,t)$bp(i)..       P(i,t)   =g= Pel(i,t)/gdata(i,"elv") - gdata(i»
,"cv")/gdata(i,"elv")*Ph(i,t) - M*b(i,t);
boiler_bp(i,t)$bp(i)..          P(i,t)   =g= Ph(i,t)/0.9 - M*(1-b(i,t));
bypass_el(i,t)$bp(i)..          Pel(i,t) =l= M*(1-b(i,t));
bp_con_bp(i,t)$bp(i)..          Pel(i,t) =g= gdata(i,"cm")*Ph(i,t) - M*b(i,t);
elh_conmin_bp(i,t)$bp(i)..      Pel(i,t) =g= gdata(i,"cv")*Ph(i,t) + gdata(i,"»
Pmin")*x(i,t) - M*b(i,t);
bypass_min(i,t)$bp(i)..         Ph(i,t)  =g= gdata(i,"Pmin")/gdata(i,"elv")*x(»
i,t) - M*(1-b(i,t));

*$offtext

*"THE HEAT IS ON ... "
bp_con_mt(i,t)$mt(i)..          Pel(i,t) =e= gdata(i,"cm")*Ph(i,t);
bp_con_mtC(i,t)..               Pelc(i,t) =e= gdata("G11","cm")*Pchp(i,t);
heat_up(i,t)..                  Ph(i,t)  =l= gdata(i,"Hmax");
heatpump(t)..                   Php(t) =l= 300;
boiler_c(i,t)..                 Pbc(i,t) =l= 500;
boiler_dc(t)..                  Pbdc(t)=l= 500;
```

```
* Max wind constraint
wcon(t)..                       Pw(t) =l= Pwmax(t);

*start-up indicator
st_up(i,t)..                    st(i,t) =g= x(i,t) - x(i,t-1);

* ramp-up con
ramp_cons(i,t)..                P(i,t) - P(i,t-1) =l= gdata(i,"RR")*x(i,t-1) +»
 gdata(i,"Pst")*st(i,t);

st_test(i,t)..                  stt(i,t) =e= gdata(i,"st")*st(i,t);

* Demand constraints
*demcon(t)..                sum(i,Pel(i,t)) + Pw(t) =e= Pd(t) + Php(t) + P12(t)»
 ;

demconh(i,t)$udh(i)..           Ph(i,t) + Pbc(i,t) + Pchp(i,t)  =g= Pheat(t)*g»
data(i,"Hmax")/3125 ;


*demconhd(t)..              sum(i$dcu(i),Ph(i,t)) + 3*Php(t) =g= Phd(t) ;
demconx(t)..               Px(t) =e= Pdx - P12(t);
*x_reserve..                sum(t,Px(t)) =l= 3800*744;



* ALTERNATIVE BETINGELSER ---------------------------------------
* ---------------------------------------------------------------
* uden decentralt område
*          demconh(t)..             sum(i,Ph(i,t)) + 3*Php(t) =g= Pheat(t) + P»
hd(t);
* uden heat pump
           demconhd(t)..            sum(i$dcu(i),Ph(i,t)) + Pbdc(t) =g= Phd(t)»
 ;
           demcon(t)..              sum(i,Pel(i,t)) + sum(i$udh(i),Pelc(i,t)) »
+ Pw(t) =e= Pd(t) + P12(t) ;
* uden x-change area
*          demcon(t)..             sum(i,Pel(i,t)) + Pw(t) =e= Pd(t) + Php(t) »
;

* spinning reserve
*          spinres(t)..            sum(i$res(i),x(i,t)) + sum(i$bp(i),x(i,t) »
- b(i,t)) =g= 3;
*          spinres(t)..            Pres + Pd(t) - sum(i$res(i),gdata(i,"Pmax"»
)*x(i,t)) =l= 0;
* ---------------------------------------------------------------
* ---------------------------------------------------------------
```

```
* Spinning reserve
spinres(t)..             sum(i$res(i),x(i,t)) =g= 3;

capcon12(t)..            P12(t) =l= P12max;
capcon21(t)..            P12(t) =g= -P12max;


costeq..                 c =e= sum((i,t), gdata(i,"fc")*P(i,t) + gdata(i,"st"»
)*st(i,t)) + sum((i,t)$udh(i),210*Pelc(i,t)/0.32 + 210*Pbc(i,t)/0.9) + sum(t,»
130*Px(t) + 210*Pbdc(t)/0.9);

model UCMIP /all/;
Option MIP = Cplex;
Option Iterlim = 1000000;
Option reslim = 3600;
Option optcr = 0.0964;
solve UCMIP using MIP minimizing c;
```

11.5.2. Code for the formulated GAMS model for the heat pump scenario

```
$Ontext
This script models a simple Unit Commitment (UC) problem using combined Mixed
Integer Programming (MIP) and Linear Programming (LP) programming, by dualizi»
ng
the multiple choise constraints with an integer x=[0;1] - also known as binar»
y
varible.

ifm. bpo:

1) ud(i)    for alle udtagsværker uden BPO (By-Pass Operation)
2) bp(i)    for alle BPO-værker
3) alm(i)   for ALLE værker (både ud og mt) UDEN BPO
$Offtext

sets
  i       generator /G1*G11/
    ud(i)  extraction units without bp /G1*G10/
    udh(i) extraction units with heat /G1*G7/
    mt(i)  back pressure /G11/
*     bp(i)  bypass units /G1*G7/
    res(i) reserve units /G1*G9/
    alm(i) all units without bypass /G1*G11/
    cu(i)  all centralized units /G1*G10/
    dcu(i) all de-centralized units /G11/
  t       time /t1*t720/
  gchar   Gen. unit characteristics /fc,Pmin,Pmax,Pst,cv,cm,Hmax,st,RR,elv/
```

```
Binary variable
          x(i,t)         asignment of Gi at t
          st(i,t)        start-up indicator 1 only if  0-1
          b(i,t)         turbine bypass of Gi at t

Table gdata(i,gchar) unit fc and cap. limits

      fc   Pmin Pmax  Pst   cv     cm   Hmax   st    RR    elv
G1    125   80  400   450  -0.15  0.75  450  10000 200   0.47
G2    125   70  350   450  -0.15  0.75  450  10000 200   0.47
G3    125   70  350   450  -0.15  0.75  450  10000 200   0.47
G4    125   80  400   450  -0.15  0.75  500  10000 200   0.47
G5    125   50  250   450  -0.15  0.75  350  10000 200   0.47
G6    125   80  400   450  -0.15  0.75  475  10000 200   0.47
G7    125   80  400   450  -0.15  0.75  450  10000 200   0.47
G8    125   50  250   400    0     0      0  10000 200   0.50
G9    125  130  650   600    0     0      0  10000 200   0.50
G10   210   0   1000  4000   0     0      0   0    10000 0.42
G11   210   0   10000 4000   0    0.55 10000  0    10000 0.90


scalars
  Pres   min. reserve capacity demand limit       /1/
  Pdx    demand in area 2                         /3000/
  P12max max. capacity on interconnection         /1200/
  M      very large number                        /10000000000/

* Reading profiles for el, heat and wind
$include 'El_demand.inc';
$include 'Heat_demand_c.inc';
$include 'Heat_demand_dc.inc';
$include 'Wind_profile.inc';

Positive variable
  P(i,t)          Boiler power (for total fuel costs)
  Pel(i,t)        El. output at G(i)
  Ph(i,t)         Heat output at G(i)
  Pw(t)           Wind power generation
  Px(t)           Power generation in exchange area (hydro primarily)
  Php(i,t)        Heat pump - capable of transforming el to heat.
  Phpdc(t)        Heat pump - capable of transforming el to heat - dc area
  Pbc(i,t)        boiler power in central area i
  Pbdc(t)         Boiler power in de-central area
  Pchp(i,t)       chp prod. in area i
  Pelc(i,t)       el from chp's in central areas

variable
  c               total costs
  c2              total costs per hour
  stt(i,t)        TEST - start-up costs of G(i)
  p12(t)          power exchange
;
```

```
Equations
  costeq            total cost calculation (both systems)
  demcon(t)         satisfy el. demand constraint
  demconh(i,t)      satisfy heat demand constraint (central units) at i
  demconhd(t)       satisfy heat demand constraint (de-central units)
  demconx(t)        satisfy el. demand in exchange erea
  wcon(t)           max. wind level
  boiler_ud(i,t)    constraint for el-heat factor of Gi's boiler (extraction)
  boiler_mt(i,t)    constraint for el-heat factor of Gi's boiler (modtryk)
$ontext
  boiler_ud_bp(i,t) constraint for el-heat factor (bypass)
  boiler_bp(i,t)    constraint for heat from bypass of Gi
  bp_con_bp(i,t)    Back pressure constraint
  elh_conmin_bp(i,t) min. electricity-heat constraint
  bypass_el(i,t)    no el. when bypass -constraint
  bypass_min(i,t)   min. boiler power at bypass
$offtext
  elh_conmin(i,t)   min. electricity-heat constraint
  elh_conmax(i,t)   max. electricity-heat constraint
  bp_con_ud(i,t)    udtags-constraint
  bp_con_mt(i,t)    Back pressure constraint
  bp_con_mtC(i,t)   back pressure constraint for central chp's
  st_up(i,t)        is G(i) starting ab at t Uhr?
  st_test(i,t)      TEST: how much is the fish?
  spinres(t)        eq for spinning reserve capacity
  ramp_cons(i,t)    eq. for ramp constraints
  capcon12(t)       upper exchange capacity limit
  capcon21(t)       lower exchange capacity limit
*  x_reserve          water reserve limit
  heat_up(i,t)      upper heat constraint
  heatpump(i,t)       max power from heat pump
  heatpump_dc(t)    max power from heat pump
  boiler_c(i,t)     boiled water for heat peak load in central
  boiler_dc(t)      boiled water for heat peak load in de-central

;


* --------------- eq. exe --------------------------- *


* El./heat constraints
boiler_ud(i,t)$ud(i)..          P(i,t)    =e= Pel(i,t)/gdata(i,"elv") - gdata(i»
,"cv")/gdata(i,"elv")*Ph(i,t);
boiler_mt(i,t)$mt(i)..          P(i,t)    =e= (Pel(i,t) + Ph(i,t))/gdata(i,"elv»
");
bp_con_ud(i,t)$ud(i)..          Pel(i,t) =g= gdata(i,"cm")*Ph(i,t) ;
elh_conmin(i,t)$alm(i)..        Pel(i,t) =g= gdata(i,"cv")*Ph(i,t) + gdata(i,"»
Pmin")*x(i,t);
elh_conmax(i,t)..               Pel(i,t) =l= gdata(i,"cv")*Ph(i,t) + gdata(i,"»
Pmax")*x(i,t);
```

```
$ontext
* BYPASS CONSTRAINTS
boiler_ud_bp(i,t)$bp(i)..       P(i,t)    =g= Pel(i,t)/gdata(i,"elv") - gdata(i»
,"cv")/gdata(i,"elv")*Ph(i,t) - M*b(i,t);
boiler_bp(i,t)$bp(i)..          P(i,t)    =g= Ph(i,t)/0.9 - M*(1-b(i,t));
bypass_el(i,t)$bp(i)..          Pel(i,t) =l= M*(1-b(i,t));
bp_con_bp(i,t)$bp(i)..          Pel(i,t) =g= gdata(i,"cm")*Ph(i,t) - M*b(i,t);
elh_conmin_bp(i,t)$bp(i)..      Pel(i,t) =g= gdata(i,"cv")*Ph(i,t) + gdata(i,"»
Pmin")*x(i,t) - M*b(i,t);
bypass_min(i,t)$bp(i)..         Ph(i,t)  =g= gdata(i,"Pmin")/gdata(i,"elv")*x(»
i,t) - M*(1-b(i,t));
$offtext

*"THE HEAT IS ON ... "
bp_con_mt(i,t)$mt(i)..          Pel(i,t) =e= gdata(i,"cm")*Ph(i,t);
bp_con_mtC(i,t)..               Pelc(i,t) =e= gdata("G11","cm")*Pchp(i,t);
heat_up(i,t)..                  Ph(i,t)  =l= gdata(i,"Hmax");
heatpump(i,t)..                 Php(i,t) =l= 350*gdata(i,"Hmax")/3125;
heatpump_dc(t)..                Phpdc(t) =l= 550;
boiler_c(i,t)..                 Pbc(i,t) =l= 500;
boiler_dc(t)..                  Pbdc(t)=l= 500;

* Max wind constraint
wcon(t)..                       Pw(t) =l= Pwmax(t);

*start-up indicator
st_up(i,t)..                    st(i,t) =g= x(i,t) - x(i,t-1);

* ramp-up con
ramp_cons(i,t)..                P(i,t) - P(i,t-1) =l= gdata(i,"RR")*x(i,t-1) +»
 gdata(i,"Pst")*st(i,t);

st_test(i,t)..                  stt(i,t) =e= gdata(i,"st")*st(i,t);

* Demand constraints
*demcon(t)..                sum(i,Pel(i,t)) + Pw(t) =e= Pd(t) + Php(t) + P12(t)»
 ;

demconh(i,t)$udh(i)..           Ph(i,t) + Pbc(i,t) + Pchp(i,t) + 3*Php(i,t) =g»
= Pheat(t)*gdata(i,"Hmax")/3125 ;

*demconhd(t)..               sum(i$dcu(i),Ph(i,t)) + 3*Php(t) =g= Phd(t) ;
demconx(t)..                Px(t) =e= Pdx - P12(t);
*x_reserve..                 sum(t,Px(t)) =l= 3800*744;

* ALTERNATIVE BETINGELSER -------------------------------------------
```

```
* ---------------------------------------------------------------
* uden decentralt område
*          demconh(t)..             sum(i,Ph(i,t)) + 3*Php(t) =g= Pheat(t) + P»
hd(t);
* uden heat pump
           demconhd(t)..            sum(i$dcu(i),Ph(i,t)) + Pbdc(t) + 3*Phpdc(»
t) =g= Phd(t) ;
           demcon(t)..              sum(i,Pel(i,t)) + sum(i$udh(i),Pelc(i,t)) »
+ Pw(t) =e= Pd(t) + P12(t) + Phpdc(t) + sum(i$udh(i),Php(i,t)) ;
* uden x-change area
*          demcon(t)..              sum(i,Pel(i,t)) + Pw(t) =e= Pd(t) + Php(t) »
;

* spinning reserve
*          spinres(t)..             sum(i$res(i),x(i,t)) + sum(i$bp(i),x(i,t) »
- b(i,t)) =g= 3;
*          spinres(t)..             Pres + Pd(t) - sum(i$res(i),gdata(i,"Pmax"»
)*x(i,t)) =l= 0;
* ---------------------------------------------------------------
* ---------------------------------------------------------------


* Spinning reserve
spinres(t)..                sum(i$res(i),x(i,t)) =g= 3;

capcon12(t)..               P12(t) =l= P12max;
capcon21(t)..               P12(t) =g= -P12max;


costeq..                    c =e= sum((i,t), gdata(i,"fc")*P(i,t) + gdata(i,"st"»
)*st(i,t)) + sum((i,t)$udh(i),210*Pelc(i,t)/0.32 + 210*Pbc(i,t)/0.9 + Php(i,t»
)*37.8) + sum(t,130*Px(t) + 210*Pbdc(t)/0.9 + Phpdc(t)*37.8);


model UCMIP /all/;
Option MIP = Cplex;
Option Iterlim = 1000000;
Option reslim = 3600;
Option optcr = 0.001;
solve UCMIP using MIP minimizing c;
```